Seabrook Station

PROBABILISTIC SAFETY STUDY

SHUTDOWN
(MODES 4, 5 and 6)

May 1988

Volume 1

New Hampshire
Yankee

Seabrook Station

PROBABILISTIC SAFETY STUDY

SHUTDOWN
(MODES 4, 5 and 6)

May 1988

New Hampshire
Yankee

SEABROOK STATION PROBABILISTIC SAFETY STUDY
SHUTDOWN (MODES 4, 5, AND 6)

By

Kenneth L. Kiper
James H. Moody, Jr.
(New Hampshire Yankee)

William Doskocil
(Yankee Atomic Electric Company)

Thomas J. Casey
(T. J. Casey Consulting)

Karl N. Fleming
(Pickard, Lowe and Garrick, Inc.)

May 1988

ABSTRACT

This report documents a probabilistic safety study of potential accidents initiating during shutdown at Seabrook Station. This supplements a full scope level 3 probabilistic risk assessment of Seabrook Station operations at power. Several objectives of this new study are to:

1. Quantify risks of accident sequences with the potential for core damage and offsite consequences that could occur during shutdown.

2. Identify specific plant features, configurations, and human actions that are the most significant risk contributors during shutdown.

3. Evaluate and recommend improvements to control and reduce the risk of serious events during shutdown via accident prevention and mitigation.

4. Establish a framework to conduct future studies and aid in the decision process.

It was concluded that the mean frequency of severe core damage due to events initiated at shutdown is 4.4E-5 per year, about 6 times less than that due to events initiated at power. The risk to public health due to shutdown events was also quantified based on source terms and consequence analyses that account for the inherently smaller inventory of fission products and decay heat at shutdown.

The public health risk was found to be extremely small and somewhat less than the very small risk from power operation quantified in previous studies. The NRC safety goals for individual risk levels are met for the combined shutdown and operation risks even with the conservative assumption of no evacuation and WASH-1400 type source terms. Further, with realistic assumptions regarding source terms and evacuation, there are no early health effects within the accuracy of the calculational codes. These results reflect procedural and instrumentation enhancements that were identified to reduce risk.

ACKNOWLEDGEMENTS

This study was conducted by New Hampshire Yankee Division of Public Service Company of New Hampshire (NHY) with support from Yankee Atomic Electric Company (YAEC) and from Pickard, Lowe and Garrick, Inc. (PLG).

PROJECT MANAGER

James H. Moody, Jr.

PRINCIPAL INVESTIGATORS

Thomas J. Casey - NHY Consultant
William Doskocil - YAEC
Kenneth L. Kiper - NHY
Karl N. Fleming - PLG

OTHER TECHNICAL CONTRIBUTORS

William Bromley - PLG
David R. Buttemer - PLG
Michael DeBay - NHY
William J. Houghton - PLG
Darvin Kapitz - YAEC
Abraham Keter - PLG
Mardyros Kazarians - PLG
Jackie Lewis - PLG
Lawrence Rau - NHY
John G. Stampelos - PLG
Keith Woodard - PLG

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF FIGURES

LIST OF TABLES

LIST OF TABLES

LIST OF TABLES

LIST OF TABLES

1.0 INTRODUCTION

This report documents a probabilistic safety assessment (PSA) of potential accidents, including loss of decay heat removal events, that could occur during shutdown at Seabrook Station. The likelihood of severe core damage with various paths for offsite release was evaluated while the plant is in Mode 4 (hot shutdown), Mode 5 (cold shutdown), or Mode 6 (refueling). The potential radiological source terms and the consequences to the public health from a hypothetical accident during shutdown were also evaluated. This study supplements the existing full scope, level 3 Seabrook Station Probabilistic Safety Assessment (SSPSA, Reference 1) and its updates (References 2 and 3) of events during power operation.

The SSPSA assessed the risk of potential accidents that could be initiated during power operation or at hot standby. This was based on the judgment that was made in all previous PRAs, including the Reactor Safety Study, that the level of risk associated with accidents that could be initiated during full power operation, while small, was substantially greater than that associated with accidents that occur during shutdown. There are many reasons to support this judgment including lower decay heat levels and smaller inventory of radionuclides, with the consequence that there is generally more time available to recover from adverse situations during shutdown. There are, however, factors that influence these margins including (a) the greater need for operator actions to prevent core damage since most automatic safety systems are disabled; (b) the relatively high equipment unavailability due to planned maintenance; (c) the potential plant configurations where the

RCS coolant inventory is drained down to the hot leg mid-plane for primary system maintenance; and (d) the opening of containment penetrations and hatches, which is allowed by Technical Specifications.

A preliminary investigation (Reference 4, RAI 21) indicated that the risk during shutdown at Seabrook appeared to be small but warranted a further look. One justification for this more detailed study was the observation that, because other analyzed contributors to the frequency of early release scenarios were also found to be quite small, the relative importance of shutdown events could be significant. Another justification was the fact that, because of their omission from previous PRAs and their deemphasis in FSAR Chapter 15 safety analyses, much less is known about the nature of the initiation and progression of shutdown events in comparison to power operation events. In addition, NRC reviews, including that by Brookhaven National Laboratories (Reference 5), identified the need for more detailed plant specific assessments. This study of risk during shutdown was initiated in Janua 1987 and provides a more complete, explicit assessment of risk for Seabrook Station for use in future decision making. Specifically, for shutdown events, the key plant characteristics that contribute most significantly were identified and examined. In addition, NRC Generic Letter 87-12 has generated an increased Industry awareness of potential risks during shutdown. In response, significant analytical and procedural guidance is under development by the Westinghouse Owners Group. This information is expected to support and complement this study.

1.1 Objectives

The objectives of this study are to:

- Quantify the risks due to accidents that initiate during shutdown, including the likelihood of serious damage to the reactor core and resultant offsite consequences, with a focus on early health effects and emergency planning strategies.

- Identify those specific plant features and configurations that contribute most significantly to risks at shutdown.

- Recommend procedural and hardware improvements to reduce the risk of serious events during shutdown.

- Establish a framework to conduct future studies of shutdown to aid in decision making.

1.2 Approach and Methodology

This detailed plant specific study of shutdown events is a continuation of an earlier preliminary investigation (Reference 4, RAI 21). It is also a follow-on to the Seabrook Station Probabilistic Safety Assessment (References 1 through 3) which provided a significant technical base as summarized below:

1. Modularized and linked event trees were used to model and quantify accident sequences based on the methodology and using advanced versions of the computer codes from the SSPSA.

2. A simplified support system event tree was used in this study based on results of the SSPSA and the unique configuration of the plant at shutdown.

3. Initiating events from the SSPSA, including internal and external hazards, were reviewed and served as the starting point for the search for internal/external events that were selected and quantified in this study.

4. Data and systems analysis from the SSPSA were used and modified for shutdown conditions as necessary.

5. Source terms for shutdown events were developed from previous source term analyses and corrected for reduced fission product and decay heat events. The same consequence analyses methodology and computer codes were used as in previous studies of at power events.

In addition, the approach used to model accident sequences is similar to that used in a research project performed for the Electric

Power Research Institute where the core damage frequency of accidents at the Zion nuclear plant during plant shutdown was assessed (Reference 6). The Zion study (NSAC-84) was an in-depth study and quantification of core melt frequency (level 1 PRA). This Seabrook specific study went further to include external initiating events, consideration of containment integrity, different release categories and source terms, as well as consequence analyses. A full scope, level 3 analysis was performed to provide a full statement of risk specifically to address emergency planning considerations.

The following summarizes the approach and methods used to conduct this evaluation of shutdown events:

1. PWR industry experience with residual heat removal (RHR) systems was reviewed to obtain insights into what could happen during shutdown. Industry shutdown events from 1977 through 1981, summarized in NSAC-52 (Reference 7), were considered. In addition, this experience base which includes 251 events was updated through 1986 in this study. As a result, this study benefited from experience gained in a total of 345 events indicating actual problems that occurred during shutdown. This experience was helpful both in identifying key accident sequences and in estimating their frequency of occurrence.

2. Seabrook Station operations and maintenance procedures used in shutdown, refueling, and startup evolutions were reviewed in detail and discussed with plant operations.

3. Items 1 and 2 guided the development of event tree models of the procedures. These event tree models were used to identify the most likely ways to initiate a loss of cooling event due to procedural errors and/or equipment failures that are appropriate for Seabrook specific procedures and design and in consideration of RHR event experience. Six event trees were developed, one for each of the following six major procedural evolutions during shutdown and startup:

   - Cold Shutdown
   - Drain RCS
   - Fill Refueling Cavity
   - Empty Refueling Cavity
   - Fill RCS
   - Startup

Event trees for the above procedures were linked and quantified to identify initiating events for separate accident response trees. The event tree models consider a range of possibilities for the configuration and status of the plant when these transients initiate (i.e., drained maintenance, refueling, or maintenance with the RCS filled).

4. Other initiating events were identified including LOCAs, loss of support systems, internal hazards (such as fires and floods), and external hazards (such as earthquakes). These events, initially identified in the SSPSA (References 1 through 3), were reviewed for applicability to shutdown. The plant configuration during shutdown was also considered with regard to potential new initiators and several of these were analyzed. Additional data analyses was performed to quantify the frequency of fires and floods unique to plant shutdown.

5. A separate set of accident event trees was developed to model plant response (operator response and recovery actions and equipment availability) to the initiating events. The accident event trees consist of an integrated set of three linked event trees that are briefly described below.

   o Support System Event Tree - A simplified support system event tree, based on the SSPSA results, was used. Initiating events first pass through this tree where the tree endstates track unique support system availability states needed to quantify the frequency of sequences in the subsequent event trees.

   o Transient Initiator Response Event Tree - Response to loss of RHR cooling and/or overpressure initiators were modeled, where event tree endstates include successful recovery, core damage endstates, or transfer to the LOCA response tree.

   o LOCA Initiator Response Event Tree - Response to LOCA initiators and LOCAs that occur in the transient response tree were modeled. Event tree endstates include successful recovery or core damage endstates.

6. A point estimate quantification of the event trees was then performed. Each event tree top event models human (operator) actions and/or systems (equipment availability). These supporting top event models were developed and quantified as conditional on the different initiating events, support systems available, and previous top event success or failure. Data and systems analysis in the SSPSA was used, modified and supplemented where possible. New data required to determine time in various shutdown conditions was derived from Zion experience in NSAC-84 (Reference 6). A large number of operator actions were identified which

are new for this study. The transient and LOCA event trees were quantified for each unique combination of support system states and initiating event.

7. The site model and consequence analyses was based on the SSPSA but was modified to account for differences in containment isolation, fission product inventory, and slower progression of releases due to reduced decay heat at shutdown. The following three offsite consequence measures are provided:

   - Exceedance frequency of 200 rem whole body dose versus distance from the containment assuming no immediate (24 hrs) protective actions. This is provided to address emergency planning considerations.

   - Exceedance frequency of acute fatalities, assuming no credit for immediate protective actions and then assuming a 2-mile evacuation.

   - Individual risk for comparison to the safety goal assuming no credit for immediate protective actions and 2-mile evacuation cases, i.e., the average risk of early fatality to individuals residing within 1-mile of the site boundary.

8. Procedure, instrument and training improvements and new administrative controls were identified during the study and the effect of these are included in the final results.

9. The final point estimate quantification was used to identify the dominant sequences, human errors, and equipment failures. An uncertainty analysis of the results was performed to quantify the range of possible results due to specific sources of uncertainty. The following key sources of uncertainty were included:

   - Variation in frequency and duration of outages.

   - Variation in fraction of time spent in each shutdown procedure.

   - Variation in time of accident initiation within the outage.

   - Variation in time to core uncovery after initiation.

   - Source term uncertainty.

   - Uncertainty due to binning different sequences in the same release category.

- Initiating event frequency uncertainty.

- Uncertainty in frequency estimation of human error rates.

- Uncertainty in component failure rates, maintenance unavailability and common cause failure rates.

- Uncertainty in the configuration of the plant: (a) the coolant level in the RCS and (b) frequency and duration of containment penetration and equipment hatch opening.

10. Sensitivity analyses were used to investigate importance of specific modeling assumptions and benefits of potential improvements.

2.0 RESULTS AND CONCLUSIONS

The purpose of this section is to summarize the results and conclusions of this study. These results include insights into the sources of risk of potential accidents during shutdown, ways to control or reduce this risk, the quantitative risk levels, and a plant and site specific risk model which will allow evaluations of the risk impact of future changes. The results of shutdown events are compared with the results from previous assessments for power operation events at Seabrook Station, with the NUREG-0396 "Dose vs Distance" curve, with the NRC Safety Goals, and with actual loss of RHR industry experience. The results and insights from this study illustrate the importance of an *a priori* examination of risk factors. Despite the large uncertainties associated with such an examination, this is preferable to waiting for the occurrence of incidents or accidents.

The risks from shutdown events described in this study assume that specific plant improvements (or their equivalent) identified during the study will be implemented. These improvements were identified by a detailed review of Seabrook systems and procedures used during shutdown and a comparison with approximately 350 reports of actual shutdown events in the nuclear industry over the past 10 years. The risk importance of these improvements became clear during the early phases of this study of shutdown events. Therefore, the final risk quantification was made assuming that they would be implemented. Sensitivity studies were then added to the final results to bound the risk impact of the improvements. The improvements include:

- Instrumentation and alarms to improve operator action and to alert the operator to incipient loss of RHR during the time when the RCS is drained to the hot leg midplane;

- o Procedures and training to cover the possible abnormal plant conditions and alternative cooling schemes;
- o Administrative controls to minimize the time in the mid-loop drained configuration, to assure that alternative cooling methods are available, and to assure control of containment integrity.

The improvements are described more fully in Section 2.7. The results of this study will be updated during development of and/or after implementation of improvements.

2.1 Core Damage Frequency

The frequency of core damage from shutdown (this study) and operation (SSPSA) is shown in Figure 2-1 in terms of a probability distribution that quantifies the uncertainties in the estimates. The parameters of the distribution are as follows:

CORE DAMAGE FREQUENCY (per calendar year)			
PARAMETER	SHUTDOWN	OPERATION	TOTAL
o 95th Percentile	1.3E-4	6.3E-4	7.2E-4
o Mean	4.5E-5	2.5E-4	2.9E-4
o 50th Percentile	1.9E-5	1.9E-4	2.3E-4
o 5th Percentile	5.8E-6	5.7E-5	7.9E-5

The mean core damage frequency at shutdown is smaller (by about a factor of 6) than that for power operation while the relative uncertainty at shutdown is larger, as illustrated in Figure 2-1. The mean to median ratio, a measure of the logarithmic uncertainty, is 2.4 for the shutdown case; 1.3 for the power operation case. Another measure of uncertainty is the percentile at which the mean falls. In the shutdown case, the mean is at about the 80th percentile; for power operation the mean is at about the 60th percentile. The relatively large uncertainty in the shutdown case is the result of large uncertainties in the operator action model and in the possible plant configurations while shutdown. Operator action is important in the model because of the absence of automatic system response.

Table 2-1 lists the contributors to core damage by initiator groups and their percent contribution. From this table, it can be seen that loss of RHR initiators make up most of the risk (82%). The highest frequency initiator of loss of RHR is hardware failure of the operating RHR pump train. This is a reflection of the long mission for which the pump must operate rather than a high failure rate of the RHR. The second highest frequency contributor is loss of RHR suction. This initiator results from inadvertent closure of the RHR suction valves or from low level cavitation when the RCS is drained down to the vessel hot legs. The initiating event frequencies from the model for these two initiators are compared to actual failures in Section 2.4.

Loss of coolant accidents make up the remainder of the risk (18%). About half of this frequency (8%) is due to LOCAs resulting from overpressure events. Overpressurization as modeled is not important from a reactor vessel or piping integrity concern per se but is a LOCA contributor because of the potential for the RHR relief valve to stick open or the RHR pump seal to rupture. The rest of the LOCA-initiator frequency is due to check valve failure during containment sump valve testing, reactor refueling cavity seal failure, and other very low frequency events.

Table 2-2 lists contributors to core damage by RCS configuration at the time of the accident. Loss of RHR events initiated when the RCS is vented and partially drained (X) and LOCAs (including LOCAs due to overpressurization) make up about 90% of the core damage frequency. This illustrates the importance of the "time to core uncovery" which is a function of the decay heat load (time after shutdown), the amount of coolant inventory above the core, and the availability of steam generator cooling. As shown in Table 2-2, the time to core uncovery is much shorter for RCS drained down (X) and for LOCAs. Thus, an important factor in determining core damage frequency is the time in the drained down mode which reduces the time for operator action to begin alternate decay heat removal methods at a given decay heat level. An effective way to reduce risk is to limit the time in draindown and, when in this mode, to strictly control containment integrity.

2.2 Public Risk

2.2.1 Early Health Risk

The mean early fatality risk curve with the "best estimate" source term and consequence model (assuming 2 mile evacuation) is illustrated in Figure 2-2. As shown, the risk from shutdown events (this study) is about an order of magnitude less than from power operation events as determined in References 2 and 3. As shown in these references, most of the early fatality risk is within two miles of the plant. Thus, modeling a 2-mile evacuation distance provides nearly as much risk reduction as a 10-mile evacuation. For that reason, the best estimate consequence analysis was done assuming a 2-mile evacuation.

The total risk assuming a 2-mile evacuation distance is more than an order of magnitude less than WASH-1400 which modeled a 25-mile evacuation distance. The WASH-1400 PWR mean is based on a mean to median ratio of 2.66 (the PWR-2 median frequency, assuming a lognormal distribution and range factor of 10). A sensitivity case with all weight on the conservative (WASH-1400 methodology) source term is illustrated in Figure 2-3. Again the risks of shutdown and operation are both low and the total mean (frequency of release) results are less than WASH-1400.

Additional sensitivities and comparisons were made with no immediate protective actions modeled. These results are provided in Figures 2-4 and 2-5 where Figure 2-5 has all weight on the conservative WASH-1400 methodology source terms. The results for shutdown events are about an order of magnitude less than power operation events as shown in Figures 2-4 and 2-5. The total mean risk in Figure 2-4 is comparable to WASH-1400. In Figure 2-5, the shutdown mean risk is comparable to WASH-1400 and operation risk is greater than WASH-1400.

Because the risk due to power operation events is so small, the relative importance of the additional small risks during shutdown is significant. However, the bottom line is not changed, that is, that the total risk is still very small. The significant factors that determine public health risk at shutdown are the absence of automatic containment isolation and the possibility of the equipment hatch being off. The equipment hatch is important because of the size of the opening, the time required to replace the hatch, and the necessity of offsite power. Table 2-3 lists the contributors to core damage by release type. As shown, important contributors to early risks occur from accidents when the RCS is drained down (X) and intact (W). A more detailed discussion of dominant core damage sequences is provided in Section 2.5.

The early fatality risk (Figure 2-2) at shutdown is dominated by release categories SR2H and SR6H with small contributions by SR2P and SR6P, as described in Section 10. The release categories SR2H and SR6H contain core damage sequences with containment open - either the equipment hatch off or the large containment air purge valves open. The model includes credit for administrative controls which minimize the time the hatch is off during shutdown and prohibit removing the hatch when the RCS is drained down. The estimated time required to replace the hatch, if it is off, helps determine the operator failure likelihood. With loss of offsite power, if the hatch is off, it cannot be replaced because of lack of power to the crane.

Table 2-4 lists the initiating event contributors to each release category and Table 2-5 shows the percent contribution of release categories to core damage frequency. For important categories contributing to early fatalities, SR2H is dominated by LOCA events - due to overpressurization or sump valve failure; SR6H is dominated by loss of RHR due to hardware failure of the pump or due to loss of support systems. These SR6H events are modeled only when the RCS is full (W) and, thus the equipment hatch could be removed. Also important are losses of RHR due to hardware failures or losses of suction with the RCS drained down (X). In this condition, the equipment hatch is modeled as being on due to administrative controls so the release is due to unisolated containment air purge valves. Hence, the final results are quite sensitive to the assumptions that these controls and other modifications are in place. The risk sensitivity of these modifications is estimated in Section 2.6.

2.2.2 Safety Goal Risk

The safety goal risk is the mean average risk of early fatality to individuals within 1 mile of the site boundary. The safety goal results for shutdown (this study), operation, and total are provided below:

	With Probabilistically Weighted Source Terms		With All Weight Given To Conservative Source Terms	
	No Evac	2-Mile Evac*	No Evac	2-Mile Evac
Operation	3.5E-8	1.1E-11	3.5E-7	1.1E-10
Shutdown	1.0E-9	4.1E-14	9.8E-9	4.1E-13
Total	3.6E-8	1.2E-11	3.6E-7	1.2E-10
Risk to Safety Goal Ratio	.07	.00002	.72	.0002
Fraction of Total Risk Due to Shutdown	.03	.004	.03	.003

Even with the conservative assumptions of no evacuation and WASH-1400 methodology source terms, the safety goal is met. The risk is more than three orders of magnitude less than the safety goal regardless of source term assumptions when evacuation out to 2 miles is modeled. This is not surprising because the 2 mile evacuation zone includes the entire population over which the safety goal risk is averaged. The small contribution made by shutdown events to the safety goal is due to several factors. These include the reduction of source terms due to radioactive decay after plant shutdown, slower evolution of accidents due to reduced decay heat, the relatively small time (37% of the year) spent in the shutdown mode, and the fact that a relatively large fraction of the shutdown risk is outside the assumed 2-mile evacuation zone.

2.2.3 200 REM Dose Vs Distance

The 200 REM whole body dose vs distance results are shown in Figure 2-6 with power operation results (Reference 3), the total (shutdown and operation), and NUREG-0396. The results shown are based

* Best estimate source term/consequence model.

on conservative source terms (WASH-1400 methodology), median frequencies, and no evacuation, consistent with the original NUREG-0396 presentation. As shown in Figure 2-6, there is a small contribution to the total 200 REM risk from shutdown. The shutdown risk alone is just visible on the scale. If the best estimate source terms were used rather than the conservative source terms, the 200 REM results for Seabrook would be off scale (low) for power operation. For shutdown, with best estimate source terms, no meteorological scenarios were found where 200 REM was achieved offsite. Previous conclusions in References 2 and 3, that the risk at 1-mile is less than the risk at 10-miles presented in NUREG-0396, are still valid even with the added risk at shutdown.

2.3 RAI 21 Comparison

An initial estimate of the risk from shutdown at Seabrook Station was documented in RAI 21 (Reference 4) in response to the NRC. The results of this study show that the RAI 21 analysis was a reasonable estimate of the shutdown risk. A comparison of the results is provided below:

	Mean Annual Frequency	
	RAI 21	This Study
Total Core Damage	1.8E-5	4.5E-5
Small Containment Opening (given Core Damage)	.03	.04
Large Containment Opening (given Core Damage)	.004 to .3	.02
Exceedence of 200 REM at 1 Mile (given Core Damage)	.003 to .02	.001

The frequency of core damage in this study is a factor of 2.5 greater than estimated in RAI 21. The conditional mean frequency of a small opening is in good agreement. The conditional frequency of a large containment opening in this study is bounded by the range estimated in RAI 21. However, with regard to consequences, RAI 21 was clearly conservative in comparison to this study. This can be seen by the much lower frequency of exceeding 200 REM at 1 mile (given core melt) for this study. The explanation for this is that RAI 21 did not incorporate a source term appropriate for shutdown conditions as was performed in this study.

2.4 Loss of RHR Data Comparison

An intermediate result from the core damage model is the frequency of loss of RHR initiating events. The frequency calculated from the model can be compared to the frequency based on actual RHR failures in PWRs to help validate this study. The results of this data review are described in Section 9.3 and are compared to the model results as follows:

- Loss of RHR - hardware failures:

  FREQ (Model) = 0.112 events/year

  FREQ (Data Review) = 0.088 events/year

- Loss of RHR - pump suction lost:

  FREQ (Model) = 0.084 events/year

  FREQ (Data Review) = 0.242 events/year

This shows good agreement for hardware failures of the model with the data from event reports. This is expected since the data used in the model (dominated by pump failure to run) is based on generic industry data.

For loss of pump suction, the model is about a factor of three below the data review. This can be explained by the Seabrook design which has two independent suction lines and the suction valve cross train depowering alignment which together reduce the likelihood of inadvertent suction line isolation. Most PWR plants have only a single RHR suction line. Also, as a result of the data review, the importance of low level pump cavitation was identified. Several improvements were identified (see Section 2.7) to aid in operator monitoring and response and are included in the model. Thus, the difference in the frequency of loss of suction is reasonable in view of the design differences and assumed modifications to be in place at Seabrook.

2.5 Dominant Core Damage Contributors

Table 2-6 lists the contributors to core damage frequency by RCS condition and initiator groups. Examination of the contributors and their relative importance yields insights into the composition of the risk and how the risk can be reduced.

Accidents with the RCS at the refueling level (RCS Configuration Y) make up less than 0.5% of the total core melt frequency. About half of this is hardware failure of the operating RHR pump and the other half, a LOCA through the refueling cavity seal ring. The low contribution of loss of RHR events and the absence of "external events" is due to the short duration in refueling and the very long time available with no active heat removal before core uncovery. The refueling cavity seal ring is a substantial metal ring with a rubber gasket seal which is tested in place before use. In the unlikely event of seal failure, the water would not drain below the vessel flange and normal RHR cooling would be unaffected.

With the RCS filled and secondary cooling available (RCS Configuration W), the time to core uncovery without active heat removal is very long except for the case of unisolated LOCAs. The LOCAs, which contribute 18% of the 29% of the core damage risk in Configuration W, are assumed to cause loss of secondary cooling ability as well as loss of primary inventory down to the hot legs. Thus, unisolated LOCAs are modeled like events in the RCS Configuration X (RCS drained down) with regard to time available for operator actions.

In the W configuration, the risk is based primarily on the relatively high unavailability of the standby train of RHR and support systems which is due in part to the relatively high unavailability due to planned maintenance. The Technical Specifications allow one train of RHR to be inoperable in this condition (with two steam generators available). Thus, it is assumed that annual or 18 month interval planned maintenance or surveillance will contribute to high unavailability of the standby train of RHR.

Loss of RHR in the W configuration makes up the remaining 11% of core damage frequency. Of this, about half is due to a scenario initiated by a seismic event which causes loss of offsite power with the subsequent hardware failure (or maintenance unavailability) of the diesel generators. Because of the possible confusion resulting from the seismic event, no credit is given to operator actions to initiate alternate cooling. Most of the rest of the core damage frequency is due to hardware failures of RHR or its support systems. The long "mission time" in this condition also contributes to the hardware failures.

The core damage frequency is dominated by accidents occurring when the RCS is drained down (RCS Configuration X). This occurs during infrequent maintenance outages or following refueling when performing steam generator inspection or maintenance and other primary system maintenance. This condition is important because of the relatively short time available for operator action when no active heat removal is available and because of the long "mission time" modeled.

Of the 71% of core damage frequency in this RCS condition, most of it (57%) is due to hardware failures and loss of suction resulting in loss of RHR. These failures are modeled as simple linear-time dependent models and are significant because of the long mission time. Of the "external events", the contributors are divided among loss of offsite power, fires, floods, seismic events, and loss of support systems (Service Water, PCC).

Core Damage Sequences

Further insights into the risk can be gained by examining the dominant (higher frequency) sequences resulting in core damage. The top 20 core damage sequences are listed in Table 2-7 in order of core melt frequency contribution. These sequences are explained and discussed below. Note that the product of the terms in each sequence is slightly greater than the sequence frequency listed. This is because of the absence of success terms in the sequences which are included in the formal quantification described in Section 5.

Sequence 1: X5N * OR2

(6.2E-2) * (1.7E-4) = 1.0E-5/yr (22.8%)

This sequence is initiated by a hardware loss of the operating RHR train with the plant drained to the vessel flange or hot leg midplane (X5N). This loss of an RHR train is assumed to be unrecoverable within 24 hours; the standby train of RHR and both trains of support system are available. The initiator category X5N includes losses of the operating RHR train anytime during a drained maintenance outage or during drained maintenance following refueling.

Following the initiating event, the operator (OR2) must recognize the loss of the operating train, must determine that the pump train is unrecoverable and must decide on the most appropriate action for continued decay heat removal. Top event OR fails if the operator fails to initiate alternate cooling prior to primary inventory boil off and core heatup. This time for heatup can be as short as 2 hours early in an outage. The operator action model is based on a time-dependent model in the <u>Handbook of Human Reliability</u> (Reference 17) as discussed in Section 6.

<u>Sequence 2</u>: X3N * OR3

(6.2E-2) * (1.7E-4) = 1.0E-5/yr (22.8%)

This sequence is initiated by a loss of suction to the operating RHR pump with the plant drained to the vessel flange or hot leg midplane (X3N). This event is caused by low level in the RCS due to level control problems or due to inadvertent closure of the RHR suction valves. The operator successfully trips the cavitating pump so that both the operating and standby RHR trains are available.

Following the initiating event, the operator (OR3) must recognize the status of the plant (no heat removal operating) and must decide on the most appropriate action to take. This actio is similar to OR2 in Sequence 1 except that it is assumed to take additional time to trip the cavitating pump. The time available until core uncovery is slightly shorter than OR2.

Sequence 3: LS * LCC

(2.1E-5) * (1.2E-1) = 2.2E-6/yr (4.9%)

This sequence is initiated by a LOCA from the RHR suction line to the containment sump occurring when the RCS is full (LS). The LOCA is a result of failure of the isolation check valve during sump valve testing. As modeled, the failure is in the suction line with the non-operating pump which drains the RCS quickly so that the operating pump fails due to cavitation. The operator successfully diagnoses the event but long term cooling (LCC) fails. With water in the sump, the long term cooling method is low pressure recirculation with the one remaining RHR pump train.

Sequence 4: SSBOW = 2.1E-6 (4.8%)

This sequence is initiated by a seismic event which causes loss of offsite power. Subsequently the diesel generators fail to start and run due to maintenance unavailability and/or hardware failure or the diesels fail due to the seismic event. Despite the long time available to core uncovery, no credit is given for operator actions to initiate gravity drain of the RWST because of the potential confusion and added stress, resulting from the seismic event.

Sequence 5: W1A * OC1 * IR1 * LCA

(9.2E-2) * (2.[illegible]E-2) * (8.1E-3) * (1.2E-1) = 2.0E-6 (4.5%)

This sequence is initiated by an overpressurization event with RHR cooling available (W1A). Overpressurization can occur when the RCS is full due to a charging - letdown imbalance (i.e., overcharging or letdown isolation) from hardware failures or operator errors. Following the initiating event, the operator fails to control the source of overpressurization or the RHR relief valve sticks open after the pressure is relieved (OC1). Thus, the loss of primary inventory continues. The operator then fails to isolate the RHR train (IR1) in order to stop the loss of inventory. Eventually the lost RCS inventory fills the containment sump so that the only long term cooling option available is low pressure recirculation (LCA) which is unavailable due to hardware failures.

Sequence 6: X6N * LC1

(6.0E-4) * (2.3E-3) = 1.3E-6 (3.0%)

This sequence is initiated by a loss of the operating RHR train with the standby train unavailable and with the RCS drained to the vessel flange or hot leg midplane (X6N). With no RHR available, the only long term cooling method, feed and bleed using the charging pump (LC1) is unavailable due to hardware failures.

Sequence 7: X5N * RR4 * LC1

(6.2E-2) * (8.9E-3) * (2.3E-3) = 1.2E-6 (2.7%)

This sequence is similar to Sequence 6. It is initiated by a loss of the operating RHR train when the RCS is drained down (X5N). Subsequently, the standby RHR train fails to start or run (RR4). The long term cooling option, feed and bleed cooling (LC1), is unavailable due to hardware failures.

Sequence 8: LS * PBA

(2.1E-5) * (6.1E-2) = 1.2E-6 (2.7%)

This sequence is initiated by the LOCA to the containment sump (LS) as described in Sequence 3. Subsequent failure of train B of PCC makes the standby train of RHR unavailable. The operating RHR pump is assumed to have failed due to pump cavitation because of the low primary level. Thus, no long term cooling methods are available since only the RHR pumps can take suction from the sumps.

Sequence 9: W1A * PBA * OC1 * IR1

(9.2E-2) * (6.1E-2) * (2.6E-2) * (8.1E-3) = 1.1E-6 (2.4%)

This sequence is similar to Sequence 5. It is initiated by an overpressurization event (W1A) which the operator fails to control (OC1). The operator also fails to isolate the RHR suction line to prevent continued primary inventory loss (IR1). The only long term cooling option, low pressure recirculation using the standby RHR train, is unavailable due to failure of PCC train B (PBA).

Sequence 10: SSBOX = 1.1E-6 (2.4%)

This sequence is similar to Sequence 4. A seismic event causes loss of offsite power, with the plant in the drained down condition. Subsequently, the diesels fail due to hardware failures or seismic-induced failures. (Planned maintenance unavailability is not included because in the drained condition, both RHR trains and support systems are required to be operable). It is assumed that electric power is non-recoverable. No credit is given for any operator actions after the seismic event.

Other Sequences

Sequence 11 (W5N * OR1) is similar to Sequence 1 (hardware failure of the operating RHR train and operator failure to diagnose the situation or failure to decide on a viable heat removal method) except that this sequence occurs when the RCS is full. Thus, much more time is available for operator action and correspondingly, OR1 is an order of magnitude less than OR2.

Sequences 12, 15, and 16 are each initiated by loss of offsite power. Sequence 12 (LOSPX * GA2 * GBD * OR5) is a station blackout due to failure of both diesel generators. Successful heat removal is still available via gravity feed and bleed. However, the operator fails to diagnose the situation or fails to decide on a viable heat removal method before core uncovery. No credit is given for recovering electric power because of the operator failure OR5. Sequence 15 (LOSPX * WA4 * WBI * LC4) is a station blackout due to failure of both trains of service water (no credit given for cooling towers) with subsequent failure of both diesels due to loss of cooling. The operator successfully diagnoses the situation but the gravity feed and bleed cooling method fails due to operator failure to control the flow. Sequence 16 (LOSPX * GA2 * OR2) is a loss of the operating RHR train due to los of offsite power and subsequent failure of diesel A (train A of RHR is assumed to be the operable train). The operator then fails to diagnose or decide on a viable heat .emoval method. This sequence is similar to Sequence 1 except that the loss of the operating RHR train is due to support system failures rather than hardware failure of the pump.

Sequence 13 (X4N * OR3) is similar to Sequence 2 except that the standby RHR pump is also unavailable. The operating RHR pump is tripped due to loss of suction and the operator fails to decide on a viable heat removal method.

Sequence 14 (LPCAX * OR2) is similar to Sequence 1 except that the loss of the operating RHR pump is due to loss of train A of PCC rather than hardware failure of the pump.

Sequences 17 (X5N * OR2 * SP2) and 18 (X3N * OR3 SP2) are the same as Sequences 1 and 2 (respectively) with the additional failure to isolate the containment before core damage (SP2). Sequences 1 and 2 are core damage with contained releases while Sequences 17 and 18 are core damage with offsite releases.

Sequence 19 (FSGAX * OR2) is similar to Sequence 1 except that the loss of the operating RHR pump is due to a fire in switchgear room A rather than hardware failure of the pump.

Sequence 20 (SLL) is a seismic event which causes a large LOCA due to steam generator and reactor coolant pump support failures. No credit is given for subsequent operator actions because of the confusion caused by the seismic event.

Additional station blackout sequences were initially in the top 20 sequences prior to electric power recovery. These sequences were initiated by loss of offsite power and subsequent failure of both diesels or one diesel and the opposite train of service water or PCC. The recovered sequences were assumed to be stable sequences because at least one train of cooling would be available. The first sequence now with ac power recovery failed is Sequence 43 (8.8E-8 per year). This sequence involves loss of offsite power while drained down (LOSPX) and failure of both diesels (GA2 * GBD) and failure to recover electric power before core uncovery (ER8). Also, the operator fails to control gravity draining of the RWST (LC4) which is being attempted in parallel with efforts to restore electric power.

2.6 Uncertainty and Sensitivity Analyses

2.6.1 Uncertainty Analysis

An uncertainty analysis was performed to quantify the range of possible results due to specific sources of uncertainty. This analysis involved assigning a distribution for each source of uncertainty in the model and then combining the distributions based on the logic from the model using a Monte Carlo simulation. The important sources of uncertainty and the Monte Carlo model for combining uncertainties are discussed in detail in Sections 5.6 and 10.

The basic sources of uncertainty that were quantified include the following:

(1) human error rates (in Section 6),

(2) component failure rates, maintenance unavailability, and common cause (Beta factors) (in Sections 7 and 9.1),

(3) initiating event frequencies for internal and external hazards (in Section 8),

(4) duration and frequency of each type of outage - Case A (non-drained maintenance), Case B (drained maintenance), and Case C (refueling) - (in Section 9.2),

(5) duration of each procedural evolution within each type of outage - Procedure trees 1 through 6 - (in Section 9.2),

(6) time available for operator action and recovery (in Section 10),

(7) configuration of the RCS - RCS filled and intact, RCS open and drained to the vessel flange or hot leg mid-plane, or RCS open and filled for refueling (in Section 9.2),

(8) frequency and duration containment penetration and equipment hatch open (in Section 10), and

(9) source term release fractions (in Section 10).

(10) source term release times and warning times for evacuation (in Section 10).

The quantification of the above sources of uncertainty gives rise to the uncertainty distributions in core damage frequency and release category frequency as listed in Table 2-5.

2.6.2 Sensitivity Analysis

In addition to the uncertainty analysis, an analysis was done of the sensitivities of the model to specific parameters and assumptions thought to be important. This analysis is summarized in Table 2-8. This helps to determine the importance of certain assumptions made in the model.

Case 1 minimizes the time in a drained down condition (X) by decreasing the frequency of drained outages (frequency of A outages from 0.45 to 0.05 per year), and decreasing the time in post-refueling drained maintenance (time in procedure tree C4 from 1440 to 144 hours per outage). The hours taken away from tree C4 were added to procedure tree C5 (time in filled condition after refueling from 193 to 1440 hours per outage) in order to preserve to total hours in refueling per outage. This factor of 10 decrease in time in drained down resulted in a factor of 2 decrease in core melt frequency. Plant damage states R2P and R2H are low pressure states so the frequency of these states decreased as expected (drained down is guaranteed to be low pressure). Plant damage state R6P increased in frequency due to the increased number of hours in postrefueling non-drained outages.

Case 2, minimizing the time in the relatively short, non-drained maintenance outages (type A outages), reduced the high pressure plant damage state R6P by about a factor of two. Total core melt was reduced by 12%. The frequency of core melt with the equipment hatch off increased because of the assumption that the hatch is off a fixed time (48 hours per year) while in the nondrained condition (W). Thus, when the fraction of time in W per year decreases, the fractional time the hatch is off in W increases. The conclusion from Case 4 is that the type A outages are not highly significant risk-wise. This is because of the presence of secondary cooling which provides at least 12 hours for recovery without active decay heat removal.

Case 3 increases the time when the RCS inventory level is at the hot leg mid-plane. This would be the case if the nozzle dams were not used during steam generator inspection and maintenance. Use of nozzle dams allows refilling to the vessel flange and provides several hours additional boil-off time. The fraction of time was increased so that almost all (.966) of the time in drained maintenance is in mid-loop operation. The results show an increase of about 22% in core damage frequency. This sensitivity modeled only the effect of the additional time for operator actions and recovery and not the increased likelihood of loss of suction to the RHR pump due to operating on the "edge" with regard to level. This case shows that reducing the time for operator action by one to two hours has some effect but does not dramatically increase risk.

Cases 4 and 5 examine the sensitivity of assumptions regarding the operator action model. Operator action OR (operator fails to diagnose the situation or fails to decide on a viable cooling method in the available time) is a time dependent model based on a curve provided in the Handbook of Human Reliability Analysis (Reference 17) as discussed in Sections 6.1 and 6.2. Case 6 shows the importance of the large uncertainty assigned to OR. When the error factor is decreased from 30 to 3 (which has the effect of decreasing the mean, for a fixed median, by a factor of about 7) the total core damage frequency decreased by a factor of 2. Increasing the mean value by a factor of 10 (Case 5) increases the core damage frequency by more than a factor of 6. These two cases show the importance of operator action during shutdown. As OR increases, it begins to dominate so that increasing OR is more significant to core damage frequency than decreasing OR. Operator action OR is less important for the plant damage states with the hatch off.

Case 6 shows the importance of gravity feed and bleed which is modeled only for low pressure sequences with loss of all support systems. Decreasing the reliability of LC4 by a factor of 40 (from 0.018 to 0.5) increases total core damage frequency by a factor of 2. Thus, the availability of gravity feed and bleed is important but minor changes to the value of the split fraction LC4 (e.g., by a factor 2) is not critical.

Case 7 increases the fraction of time the hatch is off in condition W (RCS full) but maintains the hatch on in the drained condition (X). As expected the core damage frequency is unaffected but the frequencies of R2H and R6H are increased by factors of 7 and 10, respectively. The low pressure plant damage state (R2H) increase reflects the importance of LOCAs to the likelihood of the hatch off during a core damage sequence.

Case 8 zeros out the effect of LOCAs. The effect is not too significant for total core damage frequency (20% decrease) but is very significant for plant damage states with the hatch off - R2H (factor of 4 decrease) and R6H (factor of 8 decrease). This again reflects the importance of LOCAs to the likelihood of the hatch off during a core damage sequence.

Case 9 examines the sensitivity of two pump operation, which may occur early in the outage. Clearly, the effect is minimal to core damage frequency and to plant damage states. The only potentially significant effect of 2 pump operation is that both pumps may fail due to a common loss of suction cavitation event. However, if the cross train suction depowering is correctly aligned, it is very unlikely that suction valves in both lines would be inadvertently closed.

Case 10 examines the effect of removing the autoclosure signal to the RHR suction valves. The result of removing the autoclosure is that the loss of suction events due to inadvertent valve closure are removed as potential initiators. As shown in the table, this change results in only a small reduction in risk. The risk-dominate loss of suction initiator, operator failure to control level when drained which results in low level cavitation, is not affected by this change. Even if loss of suction were completely eliminated as an initiating event, the core damage frequency would be reduced by only about 26% (see Table 2-6).

Case 11 examines the effect of removing from the model all the assumed improvements (see Section 2.7 for a discussion of the improvements included in the model). This results in the following: increased frequency of loss of suction initiating events due to low level when drained (due to inadequate level monitor and absence of low level alarms); lower reliability of operator actions (top events TP, OR, OL) in response to the initiating event (due to lack of training and procedures); and increased time with the RCS at mid-loop and with the equipment hatch off (due to lack of administrative controls). From Table 2-8 it is clear that the effect of the improvements is very significant. The core damage frequency increases by a factor of 35. Even more significant is the effect on plant damage states R2P and R2H which increase in frequency by a factor of more than 700. This is due to the combined effects of increased time in mid-loop (see Case 3), increased probability of error in operator action OR (see Case 5), no credit for gravity feed and bleed cooling (see Case 6), and increased time the equipment hatch is off (see Case 7). Hence, it is clear from this sensitivity case that without these important, yet low cost modifications, that shutdown events would fully dominate both core damage and early health risk.

2.7 Plant Improvements

Based on this study, a number of improvements were identified which improve the operator awareness and response and minimize time in higher risk plant configurations and thereby reduce potential risk levels. These improvements (or their equivalent), which are included in the model, are as follows:

- Instrumentation and alarms during RCS drained down

  Level Monitoring - A delta pressure sensing device or equivalent such that positive, reliable level monitoring is available in the control room during all shutdown conditions.

  Alarm Instrumentation - High priority (audible and visual) alarms in the control room for low RHR flow (< 1000 gpm) and low vessel level (slightly above vortexing level) during draindown. These alarms would alert the operator of the need for immediate action to prevent vortexing pump failure.

- Shutdown Procedures

  Additional guidance and precautions to reduce the likelihood of loss of RHR (i.e., preventive).

- Abnormal Operating Procedures

  Alternative Cooling - Procedure which would identify possible alternative cooling available for loss of RHR events for different RCS configurations. This would include guidance for secondary cooling options, feed and bleed cooling with steam generator manways open, gravity feed and bleed cooling from RWST, etc.

  RCS Inventory - Additional procedures to provide information on the time to core boiling and to core uncovery as a function of time after shutdown and RCS inventory.

  Containment Isolation - Additional procedures to emphasize the importance of functionality of containment isolation during shutdown.

o **Administrative Controls**

Alternative Cooling - With the RCS intact, secondary cooling should be functional with at least two steam generators. When the RCS is drained down, the RCS should be vented sufficiently to assure the ability of gravity feed-and-bleed from the RWST.

Equipment Hatch - The hatch should be removed only when the RCS is full with secondary cooling available. When the hatch is removed, it should be replaced as soon as practical to reduce the likelihood of the hatch off during accidents. Alternatively, future evaluations may consider plant specific data on time to replace the hatch versus time to core uncovery (i.e., late in outage after refueling, replacement of hatch may be easily accomplished during draindown).

Containment Integrity - The current status of each isolation valve and penetration should be maintained to provide confidence that all penetrations are or will be closed after an abnormal event.

o **Training**

Additional operator training that specifically covers all of the above changes. The training should also emphasize the time to core uncovery (with loss of cooling) for various plant configurations, the importance of early containment isolation, and the primary instrumentation to monitor (e.g., core exit thermocouples).

The results of this study will be evaluated and revised, if necessary, based on the actual implementation of these plant improvements. The sensitivity studies in Section 2.6.2 clearly show the importance of the improvements to core damage and public risk. Including the improvements in the model obviated the need to examine some otherwise potentially important issues. For example, the assumption of a large, high point, hot leg vent (e.g., a pressurizer safety valve removed) whenever the RCS is drained down eliminated concern of the plant configuration with a cold leg open and either the hot leg intacted or nozzle dams in both hot and cold legs. In either configuration, an increase in pressure in the hot leg or region above the core would cause reactor coolant to be expelled via the cold leg opening. This increase in pressure can be the result of a loss of RHR or a gas intusion (N_2) into the RCS from the PRT. This would result in core heatup and damage in a short period of time. The cold leg opening could be a steam generator manway or a large leak due to RCP seal/impeller or check valves maintenance, etc. All of these scenarios which would result in very short time to core uncovery would be eliminated by the presence of a hot leg vent.

2.8 Conclusions

The principle conclusion is that, with the benefit of relatively low cost modifications and administrative controls identified in this study, the frequency of core damage during shutdown is small, but not negligible, in comparison to power operation (see Figure 2-1). The risk at shutdown is influenced by the fission product inventory and decay heat loads, different plant configurations unique to shutdown, and greater reliance on operator actions to assure safe plant operation. The decay heat load quickly decreases to 2% of full power (68.5 MW) just one hour after shutdown but is still at 0.2% of full power (6.9 MW) at one month and 0.15% (5.1 MW) one hundred days after shutdown. Thus, a significant heat load is present in the core many days after initial shutdown. During shutdown, the plant is placed in configurations not permitted at power but which are required for plant maintenance. These include draining the RCS to the mid-plane of the hot legs for primary system inspection; taking one train of RHR and support systems out for planned maintenance; and opening the equipment hatch for major maintenance inside containment.

The following summarizes the additional conclusions of the study:

QUANTITATIVE CONCLUSIONS

- o Core damage mean frequency when shutdown is less than during operation by about a factor of 6.

- The early fatality risk from shutdown is about an order of magnitude less than operation (Figures 2-2 through 2-5).

- With 2-mile evacuation assumptions the total (shutdown and operation) mean early fatality risk is less than WASH-1400 results which modeled 25-mile evacuation (Figures 2-2 and 2-3).

- Individual risk safety goals are met even with the conservative assumptions of no immediate protective actions and WASH-1400 methodology source terms. The risk is several orders of magnitude less than the safety goal for the best estimate model which assumes 2-mile evacuation. The longer times and reduced fission product inventory associated with accidents during shutdown result in insignificant risks within 1-mile of the site.

- The 200 REM whole body dose versus distance curve is dominated by risk from operation. The contribution from shutdown is just on scale. The total conditional frequency of 200 REM at 2-miles is about 0.001.

- Previous studies (References 2, 3) concluded that an evacuation planning zone (EPZ) of less than two miles can be justified for Seabrook Station using the same basis used in NUREG-0396 to select a 10-mile EPZ for all U.S. sites. This conclusion is still valid with the shutdown risk added to the operational risk (Figure 2-6).

PLANT IMPROVEMENTS

- Cost effective plant improvements in the form of instrumentation, controls, procedures, and training were identified to ensure low risks during shutdown.

- Sensitivity analyses clearly show that without the relatively low cost modifications and new administrative controls identified and incorporated into the study, shutdown events would dominate both core damage frequency and early health risk.

  Hence, this study is expected to have a major impact in terms of risk management.

- The results show that risk is very sensitive to the reliability of the operators and to the controls on containment integrity (Table 2-8). This is expected since the plant is in a manual mode during shutdown. The results are based on plant enhancements to improve operator awareness and response and to minimize time in high risk plant configurations such as the RCS drained down or having the equipment hatch removed.

LOCA INITIATORS

- The results also show that LOCAs are the important contributors to early health risks. Table 2-3 shows that the "large containment opening" release type, which accounts for the majority of public risk, is dominated by RCS configuration W, RCS full. This configuration is, in turn, dominated by LOCA initiating events as shown in Table 2-6. The explanation is that if a LOCA occurs, which is modeled to occur only when the RCS is pressurized (Configuration W), the equipment hatch is permitted to be off. However, because of the loss of primary coolant inventory, the time for operator action to restore core cooling is relatively short. Also, because of this short time to core uncovery, it is very unlikely that the hatch could be restored before the containment is uninhabitable.

Because of the importance of LOCAs, the potential sources of LOCA were carefully investigated. A number of LOCA initiators were included in the model, such as a stuck-open relief valve (see Section 3.2.3). Other LOCAs were considered but not included in the model, such as random pipe breaks (see Section 3.2.5) and LOCAs through low pressure piping outside containment (see Section 7.6.1). Also, in particular, LOCA L3 (LOCA to the RWST through RH-V33) would be much higher in frequency if the crosstie valves (RH-V21, V22) were left open when initiating RHR cooling, that is, if the RHR were required to be in the ECCS "injection mode" in Mode 4. Because of the importance of LOCAs, they deserve special attention in training and emergency response procedures.

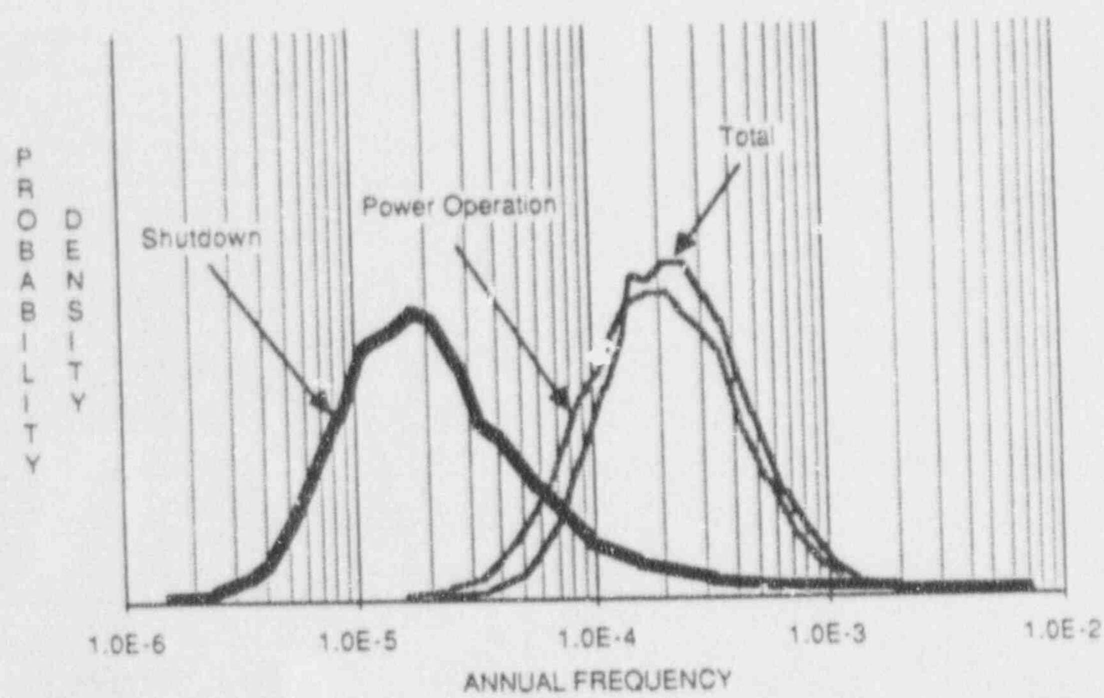


FIGURE 2-1

CORE DAMAGE FREQUENCY

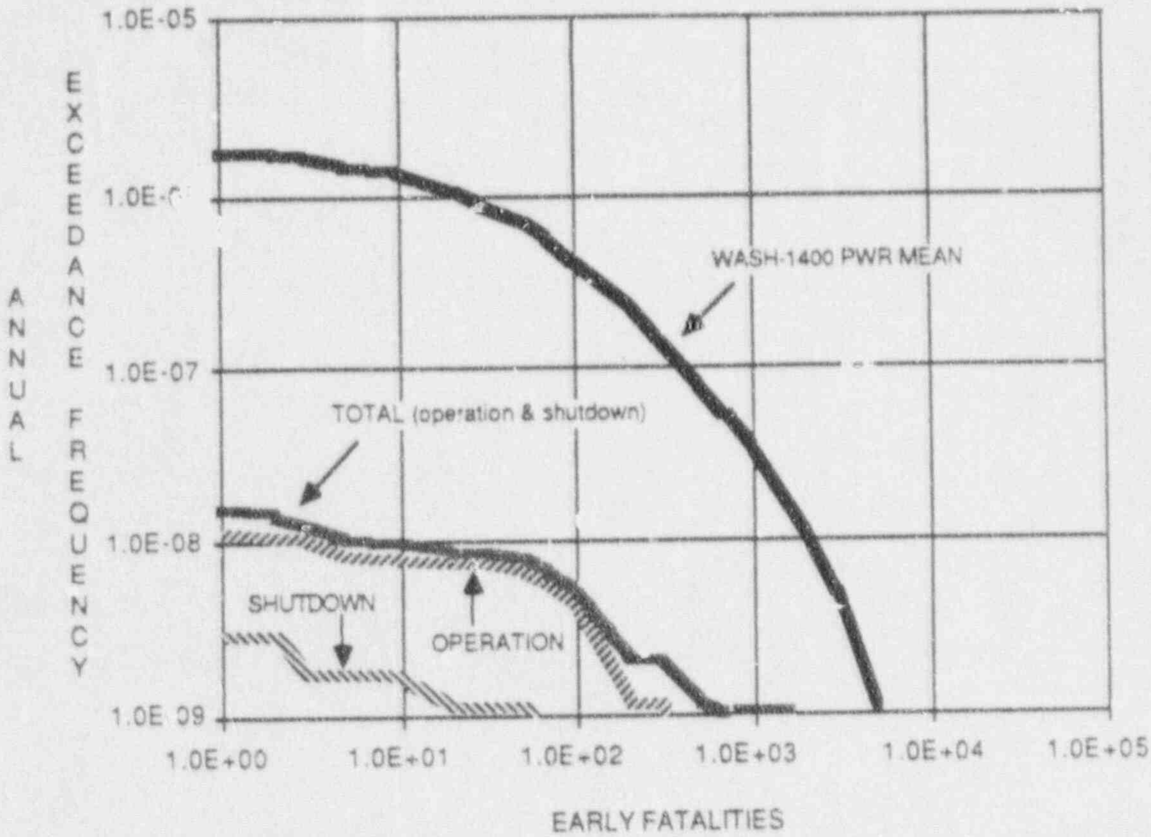


FIGURE 2-2

EARLY FATALITY RISK (Mean Frequency) with 2 MILE EVACUATION and PROBABILISTICALLY WEIGHTED SOURCE TERMS

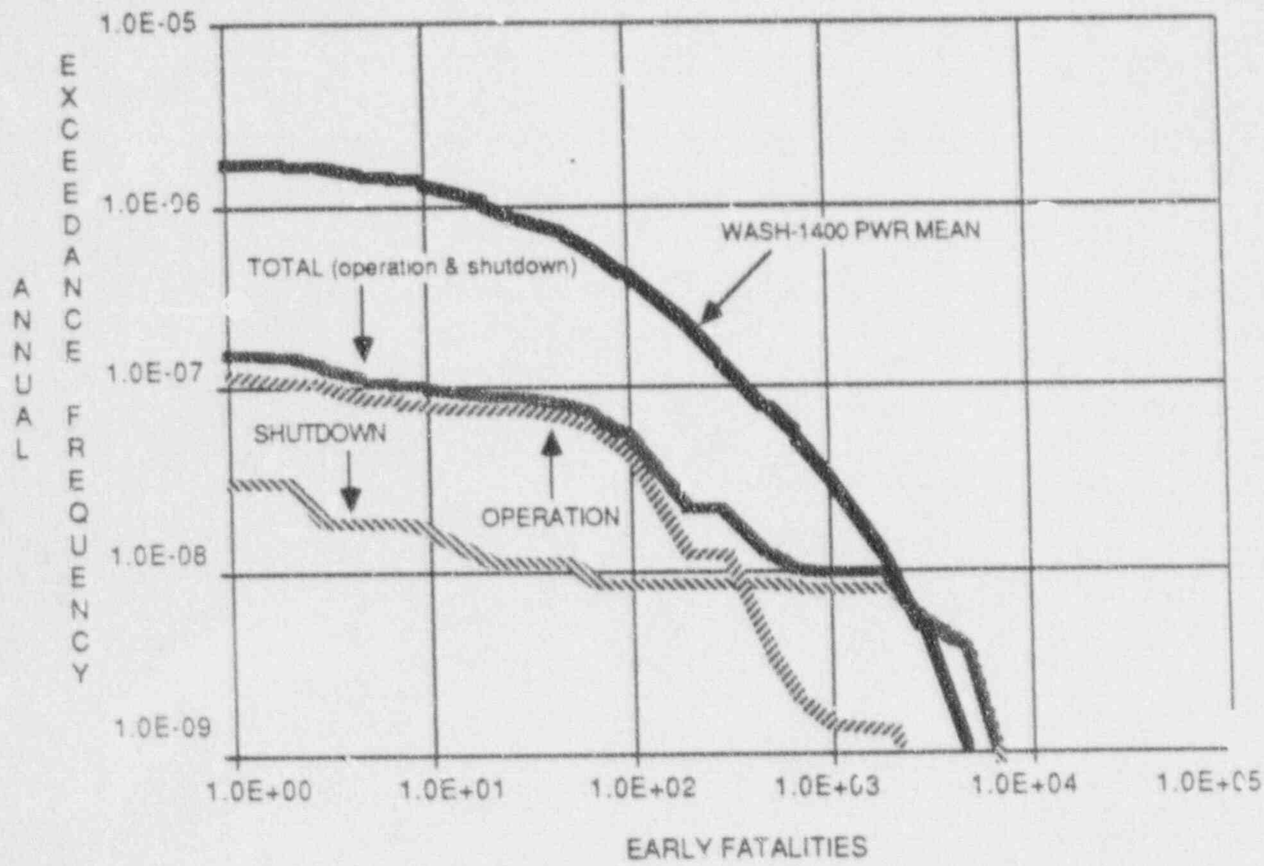


FIGURE 2-3

EARLY FATALITY RISK (Mean Frequency) with 2 MILE EVACUATION and ALL WEIGHT ON CONSERVATIVE SOURCE TERMS

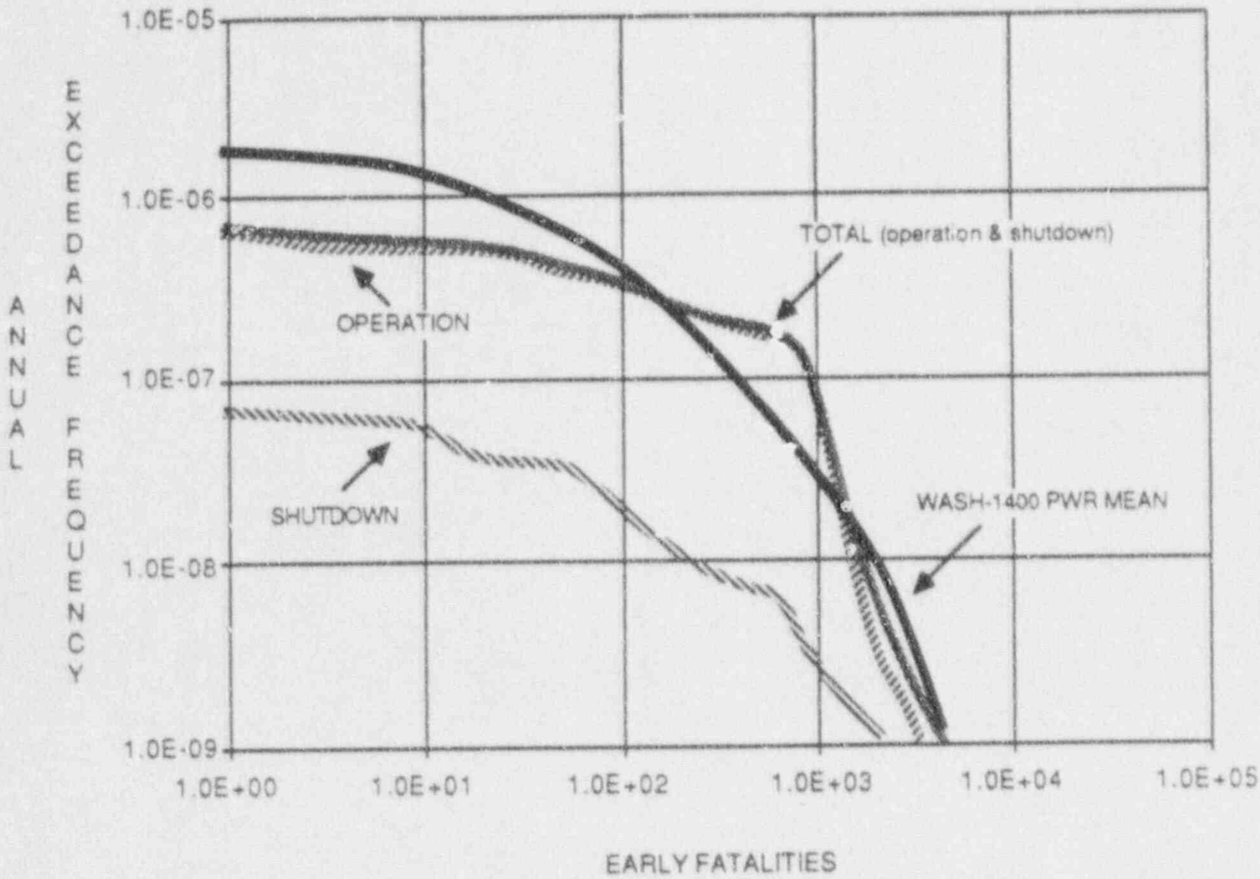


FIGURE 2-4

EARLY FATALITY RISK (Mean Frequency) with NO IMMEDIATE PROTECTIVE ACTIONS and PROBABILISTICALLY WEIGHTED SOURCE TERMS

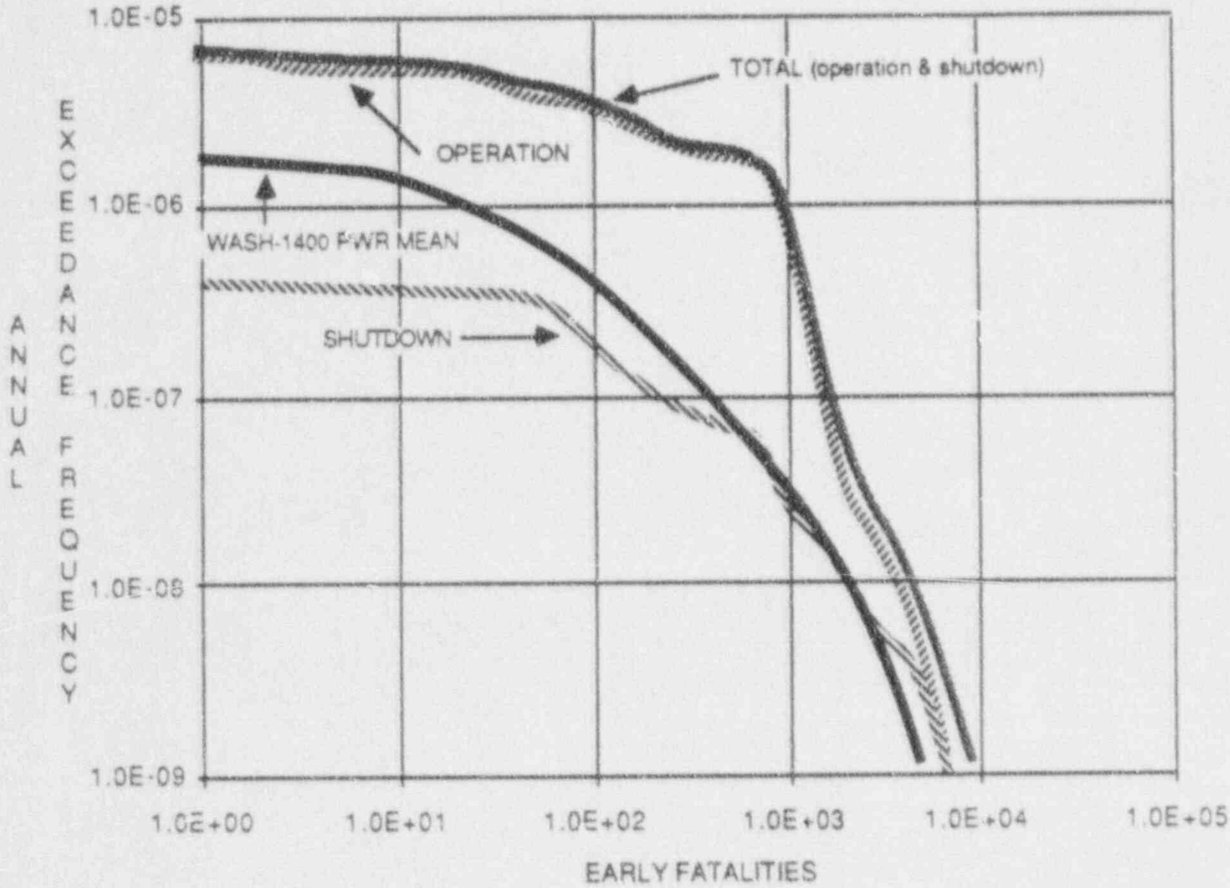


FIGURE 2-5

EARLY FATALITY RISK (Mean Frequency) with
NO IMMEDIATE PROTECTIVE ACTIONS and
ALL WEIGHT ON CONSERVATIVE SOURCE TERMS

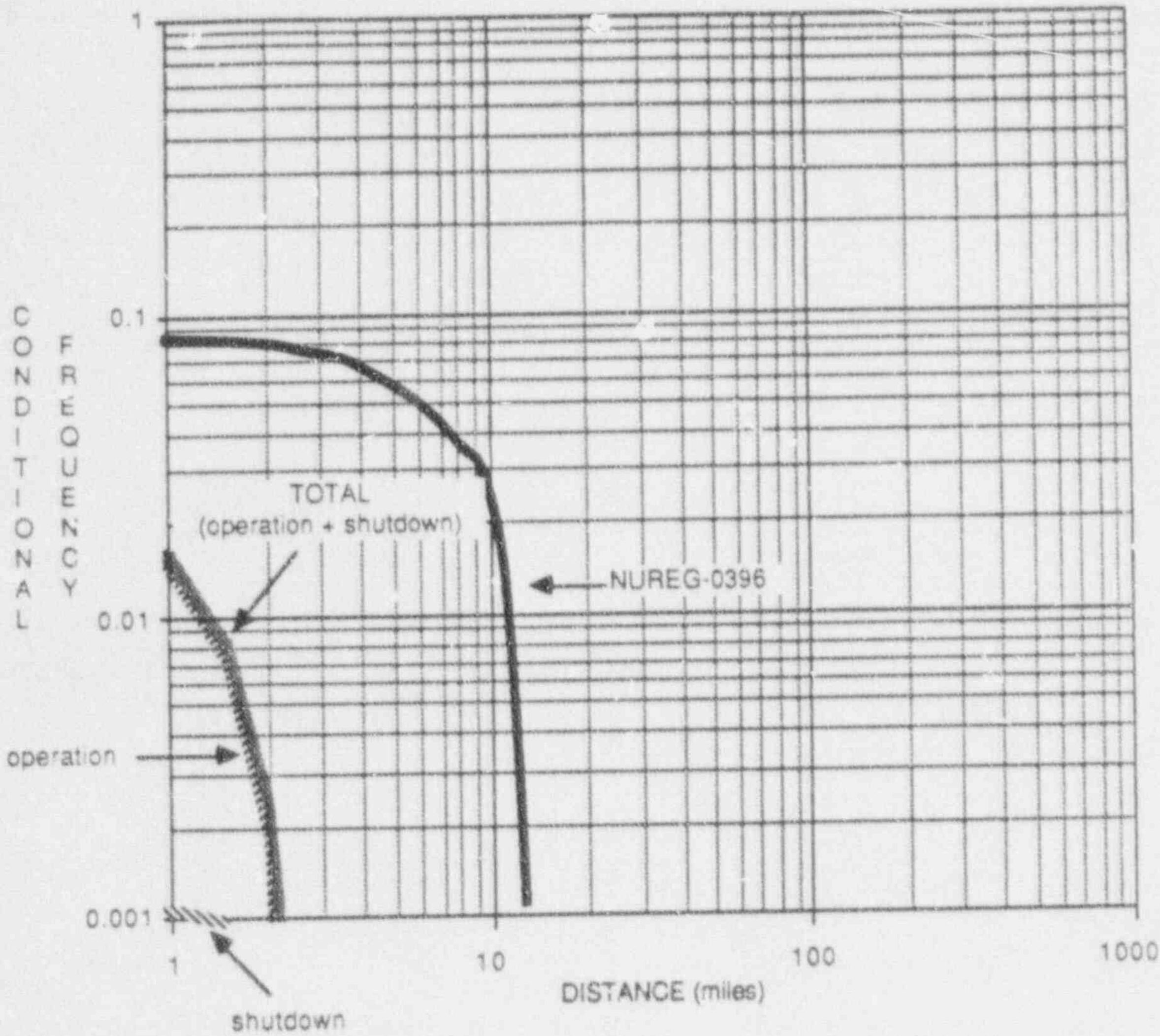


FIGURE 2-6

200 REM WHOLE BODY DOSE vs. DISTANCE
for MEDIAN FREQUENCIES
NO IMMEDIATE PROTECTIVE ACTIONS
WASH-1400 METHODOLOGY SOURCE TERMS

TABLE 2-1

CONTRIBUTORS TO CORE DAMAGE BY INITIATING GROUP

INITIATOR GROUP	PERCENT CONTRIBUTION	CONTRIBUTORS	PERCENT CONTRIBUTION
Loss of RHR - Internal Events	61	Hardware failures of RHR or Support systems	35
		Loss of RHR Suction from RCS	26
Loss of RHR - External Events	21	Seismic Event	8
		Loss of Offsite Power	6
		Loss of Other Support Systems	3
		Fires and Floods	4
LOCA	18	LOCA due to Sump Valve Failure	9
		LOCA due to RCS/RHR Overpressure	8
		Other Events	1
TOTAL	100		100

TABLE 2-2

CONTRIBUTORS TO CORE DAMAGE BY RCS CONFIGURATION

RCS CONFIGURATION	TIME IN RCS CONFIGURATION (Mean)	TIME TO CORE UNCOVERY (Range)	PERCENT CORE DAMAGE CONTRIBUTION: TOTAL	SEQUENCE TYPE (b)	
W - RCS Filled with Secondary Cooling Available.	1455 hours per year	10 hours to 36 hours (a)	29	Loss of RHR	11
				Overpressure	8
				LOCA	10
X - RCS Drained to Vessel Flange or to Hot Leg Mid-plane.	1627 hours per year	2 hours to 12 hours	71	Loss of RHR	71
				Overpressure	----
				LOCA	----
Y - RCS Filled to Refueling Level.	134 hours per year	72 hours to 160 hours (a)	0.5	Loss of RHR	0.3
				Overpressure	----
				LOCA	0.2

(a) The time for core uncovery for unisolated LOCAs is assumed to be equal to the X RCS configuration time.

(b) The entries with a dash (-) indicate sequence types that are not possible under the given RCS configuration (e.g., overpressurization can occur only when the RCS is filled and intact - W).

(c) The range in times is due to a corresponding range in times after shutdown at which RHR is lost.

TABLE 2-3

CONTRIBUTORS TO CORE DAMAGE BY RELEASE TYPE

RELEASE TYPES	RELATIVE RISK SIGNIFICANCE		PERCENT CONTRIBUTION	
	EARLY FATALITIES	LATENT FATALITIES	TOTAL	RCS CONFIGURATION
Large Containment Opening	Major	Major	1.5	W - 1.2 X - 0.3 Y - < 0.1
Small Containment Opening	Minor	Major	3.8	W - 1.0 X - 2.8 Y - < 0.1
Intact Containment	None	None	95	W - 27 X - 68 Y - 0.4

TABLE 2-4

CONTRIBUTORS TO RELEASE CATEGORIES BY INITIATING GROUP/RCS CONDITION
(events per year)

Initial RCS Configuration/ Initiating Event	Release Categories SR2D	SR2P	SR2H	SR6D	SR6P	SR6H	TOTAL
RCS Condition X (Drained):							
Hardware Failure of RHR	1.3E-5	5.4E-7	7.0E-8	-------	-------	-------	
Loss of Suction Failure	1.1E-5	4.5E-7	5.8E-8	-------	-------	-------	
Loss of Offsite Power	2.5E-6	1.0E-7	2.8E-10	-------	-------	-------	
Loss of Support Systems	8.6E-7	3.6E-8	4.6E-9	-------	-------	-------	
Fire/Flood	1.4E-6	5.8E-8	6.6E-9				
Seismic Event	1.1E-6	4.4E-8	1.2E-10				
							3.1E-5
RCS Condition W (Filled):							
Hardware Failure of RHR	-------	-------	-------	1.4E-6	3.6E-8	2.1E-8	
Loss of Suction Failure	-------	-------	-------	3.7E-7	6.4E-9	1.1E-9	
Loss of Offsite Power	-------	-------	-------	1.5E-7	2.6E-9	5.3E-9	
Loss of Support Systems	-------	-------	-------	2.5E-7	4.3E-9	1.6E-10	
Fire/Flood	-------	-------	-------	2.3E-7	4.7E-9	3.1E-9	
Seismic Event	-------	-------	-------	2.1E-6	8.9E-8	7.6E-8	
Seismic LOCA	3.5E-7	1.5E-8	1.3E-8	-------	-------	-------	
Overpressurization LOCA	3.4E-6	1.4E-7	1.4E-7	-------	-------	-------	
LOCA - Sump Valve Failure	3.5E-6	1.4E-7	1.4E-7	-------	-------	-------	
							1.3E-5
RCS Condition Y (Refueling):							
Failure of RHR	1.2E-7	2.0E-9	2.5E-10	-------	-------	-------	
Refueling Cavity Seal Failure	5.4E-8	2.5E-9	2.9E-10	-------	-------	-------	
Other	6.6E-9	3.0E-10	3.5E-11				1.8E-7
TOTAL	3.7E-5	1.6E-6	4.4E-7	4.6E-6	1.5E-7	1.1E-7	4.4E-5

TABLE 2-5

THE CONTRIBUTIONS RELEASE CATEGORIES
MAKE TO CORE DAMAGE FREQUENCY DURING SHUTDOWN

RELEASE CATEGORIES	FREQUENCY (events/year)				PER CENT OF TOTAL (mean)
	95th	Mean	50th	5th	
SR1D		5.4E-8*			< 0.1
SR1P		2.5E-9*			< 0.1
SR1H		2.9E-10*			< 0.1
SR2D	1.2E-4	3.9E-5	1.5E-5	4.0E-6	86.7
SR2P	4.7E-6	1.5E-6	5.0E-7	9.0E-8	3.3
SR2H	1.3E-6	4.6E-7	2.5E-7	4.6E-8	1.0
SR6D	1.5E-5	4.6E-6	2.0E-6	3.6E-7	10.2
SR6P	5.4E-7	1.3E-7	5.1E-8	7.1E-9	0.3
SR6H	4.7E-7	1.1E-7	5.1E-8	6.4E-9	0.2
TOTAL CORE DAMAGE	1.3E-4	4.5E-5	1.9E-5	5.8E-6	100

* point estimates - no uncertainty calculations due to low frequency

TABLE 2-6

CONTRIBUTION TO CORE DAMAGE BY RCS CONFIGURATION/INITIATING GROUP

RCS CONDITION	PERCENT CORE DAMAGE CONTRIBUTION	INITIATOR GROUP	PERCENT	CONTRIBUTION	PERCENT
X - RCS Drained to Vessel Flange or to Hot Leg Midplane.	71	Loss of RHR - Internal Event	57	Hardware Failure	31
				Loss of Suction	25
		Loss of RHR - External Event	14	Loss of Offsite Power	5.9
				Loss of Support Systems	2.1
				Fire/Flood	3.4
				Seismic Event	2.5
W - RCS Filled with Secondary Cooling Available.	29	Loss of RHR - Internal Event	4	Hardware Failure	3.5
				Loss of Suction	0.9
		Loss of RHR - External Event	7	Loss of Offsite Power	0.4
				Loss of Support System	0.6
				Fire/Flood	0.5
				Seismic Event	5.2
		LOCA	18	Overpressure Event	8.3
				Containment Sump Valve	8.6
				Other	0.9
Y - RCS Filled to Refueling Level	0.5	Loss of RHR - Internal Event	0.3	Hardware Failure	0.3
				Loss of Suction	< 0.1
		LOCA	0.2	Refueling Cavity Seal Failure	0.2
				Other	< 0.1
TOTAL	100		100		100

TABLE 2-7

ACCIDENT SEQUENCES RANKED BY
CONTRIBUTION TO CORE MELT FREQUENCY

RANK	(a) INITIATING EVENT	(b) SUPPORT SYSTEM FAILURES	(c) PLANT RESPONSE FAILURES	MEAN CORE MELT FREQ	PERCENT CONTRIBUTOR
1	X5N		OR2	1.0E-5	22.8
2	X3N		OR3	1.0E-5	22.8
3	LS		LCC	2.2E-6	4.9
4	SSBOW*			2.1E-6	4.8
5	W1A		OC1 * IR1 * LCA	2.0E-6	4.5
6	X6N		LC1	1.3E-6	3.0
7	X5N		RR4 * LC1	1.2E-6	2.7
8	LS	PBA		1.2E-6	2.7
9	W1A	PBA	OC1 * IR1	1.1E-6	2.4
10	SSBOX*			1.1E-6	2.4
11	W5N		OR1	8.4E-7	1.9
12	LOSPX	GA2 * GBD	OR5	7.5E-7	1.7
13	X4N		OR3	5.0E-7	1.1
14	LPCAX		OR2	4.7E-7	1.1
15	LOSPX	WA4 *WBI	LC4	4.6E-7	1.0
16	LOSPX	GA2	OR2	4.5E-7	1.0
17	X5N		OR2 * SP2	4.2E-7	1.0
18	X3N		OR3 * SP2	4.2E-7	1.0
19	FSGAX		OR2	4.1E-7	0.9
20	SLL*			3.5E-7	0.8
OTHER				6.8E-6	15.5
TOTAL				4.4E-5	100.0

* These "initiating events" are actually complete sequences initiated by a seismic event. The sequences are discussed and quantified in Section 8.1.1.

TABLE 2-7

ACCIDENT SEQUENCES RANKED BY
CONTRIBUTION TO CORE MELT FREQUENCY

(a) Initiating Events:

ID	Description	Mean Frequency
X3N	Loss of RHR Suction - RCS Configuration X (drained)	6.2E-2
X4N	Loss of RHR Suction and Standby Pump Unavailable (X)	3.1E-3
X5N	hardware Loss of Operating RHR (X)	6.2E-2
X6N	Hardware Loss of Operating and Standby RHR (X)	6.0E-4
W1A	Overpressure Event	9.2E-2
W5N	Hardware Loss of Operating RHR (W)	5.4E-2
LOSPX	Loss of Offsite Power (X)	3.0E-2
LPCAX	Loss of PCC Train A (X)	2.9E-3
FSGAX	Fire in Switchgear Room A (X)	2.5E-3
SSBOW	Seismic Station Blackout (W)	2.3E-6
LS	LOCA to the Containment Sump	2.1E-5
SLL	Seismic Large LOCA	3.8E-7

(b) Support System Failures:

ID	Description	
GA2	D/G Train A Failure - RCS Configuration X	1.1E-1
GA2 * GBD	D/G Trains A and B Failure (X)	1.5E-2
WA4 * WBI	Service Water Trains A and B Failure given LOSP (X)	1.1E-3
PB1	PCC Train B Failure - RCS Configuration W	6.1E-2
PBA	PCC Train B Failure given Train A Successful (W)	6.1E-2

(c) Plant Response Failures:

ID	Description	
OR1	Operator Fails to Diagnose Event - RCS Configuration W	1.7E-5
OR2	Operator Fails to Diagnose Loss of RHR Event (X)	1.7E-4
OR3	Operator Fails to Diagnose Loss of RHR Suction Event (X)	1.7E-4
RR4	Standby RHR Train Failure to Start and Run (X)	8.9E-3
LC1	Long Term Cooling (feed and bleed) Failure (X)	2.3E-3
LC4	Long Term Cooling (gravity feed and bleed) Failure (X)	1.8E-2
LCA, LCC	Long Term Cooling (low pressure recirc.) Failure given Unisolated LOCA	1.2E-1
OC1	Operator Failure to Stop Overpressure Condition or Relief Valve Stuck Open	2.6E-2
IR1	Operator Failure to Isolate RHR Suction Valves given LOCA	8.1E-3
SP2	Failure to Isolate Containment - Small Penetration Open (X)	4.0E-2

TABLE 2-8

SUMMARY OF SENSITIVITY STUDIES

Case No.	Sensitivity Studies	RATIO OF SENSITIVITY CASE TO BASE CASE				
		Core Melt Total	R2P	R2H	R6P	R6H
1.	Minimize time in a drained down condition (X) by a factor of 10.	0.51	0.43	0.63	1.65	0.94
2.	Minimize frequency of type A outages - non-drained maintenance outages (mean annual frequency from 3.4 to 0.34).	0.88	0.92	1.28	0.47	1.22
3.	Increase time in mid-loop operation (fraction of time in X, drained to the hot leg mid-plane, from 0.034 to 0.966, given drained maint.).	1.22	1.26	1.09	1.00	1.00
4.	Decrease uncertainty in top event OR (error factor from 30 to 3).	0.50	0.47	0.81	0.83	0.93
5.	Increase top event OR by a factor of 10.	6.44	6.78	3.13	2.84	1.80
6.	Minimize credit for gravity feed and bleed cooling (LC4 from 0.018 to 0.5).	1.93	2.06	1.00	1.00	1.00
7.	Increase time equipment hatch is off in condition W - RCS full (fraction of time in W with equipment hatch off from 0.033 to 0.33).	1.00	1.00	7.00	1.00	9.70
8.	Zero out effect of LOCAs.	0.80	0.78	0.25	0.86	0.13
9.	Two pump RHR operation.	1.0	1.0	1.0	1.0	1.0
10.	Remove autoclosure of RHR suction valves.	0.95	1.0	0.91	1.0	0.95
11.	Zero out effect of assumed improvements.	35	746	725	31.7	10.6
	Base Case (mean annual frequency)	4.5E-5	1.5E-6	4.6E-7	1.3E-7	1.1E-7

3.0 PLANT MODEL

3.1 Overview of the Model

The plant model defines the progression of accident sequences from initiating events to plant damage states. This model provides the basic framework for estimating the frequencies of accidents and it sets the stage for performing the containment and source term analysis. It is comprised of a logical combination of initiating fault and equipment operation and operator actions in response to the initiating events. The sequence of failures that are of interest are those that result in inadequate core cooling and eventual core damage. The plant model is composed of three distinct parts:

- Initiating Events

  The events that cause a plant upset condition (e.g., loss or degradation of decay heat removal, overpressurization, loss of offsite power) and which require operator and hardware response.

- Support Systems Event Tree

  The functional relation among auxiliary systems (e.g., electric power, component cooling) whose response to the initiating events directly affects the availability of front line systems (e.g., RHR, charging pump) that are needed to respond to the initiating event.

- Plant Response Event Trees

  The logical relation among operator actions and equipment and instrumentation in front line systems that must function correctly to prevent a loss of core cooling and eventual core damage. Separate trees are provided for LOCA and non-LOCA (transient) initiators. The possibility for transient-induced LOCAs is also modeled. This combination of operator and hardware successes necessary and sufficient to prevent a core damage event is dependent on the initiating event and the availability of support systems.

The end result of the plant model is a set of core damage accident sequences whose end states (plant damage states) define key conditions of the RCS and containment at the time of core damage necessary for source term/consequence determination. This allows core damage sequences to be properly related to offsite consequences. The general flow of the plant model is shown in Figure 3-1.

The initiating events can be categorized into four groups as follows:

- <u>Procedure-Initiated Transients</u>

  The plant upset conditions (loss or degradation of decay heat removal, or overpressurization) which occur during the course of plant shutdown evolutions. These events which include operator errors and equipment failures are modeled explicitly in the procedural event trees (see Section 4) and are used as initiators to the transient response event trees.

- <u>Procedure-Initiated LOCAs</u>

  Events that result in substantial losses of primary coolant inventory which occur during the course of plant shutdown evolutions. These events which include operator errors and equipment failures are also modeled explicitly in the procedural event trees and are used as initiators to the transient and LOCA response event trees.

- <u>Support System Failures</u>

  Failures of a single train or both trains of normally operating systems which support RHR decay heat removal. The support systems include Service Water, Primary Component Cooling, and Electric Power. These failure events are handled separate from the procedural event trees.

- <u>Internal/External Hazard Events</u>

  Events such as fires, floods, seismic events, which result in a degradation or loss of RHR decay heat removal.

Initiating events are described further in Section 3.2.

The Support System event tree is described in Section 3.3. The various combinations of success and failure of support systems are grouped according to the following end state descriptions:

- FO - both support trains A and B are available (none failed)
- FA - Support train B only available (train A failed)
- FB - Support train A only available (train B failed)
- FAB - No support trains available (trains A and B failed)

This grouping was achieved by conservatively modeling the loss of a support train as loss of AC electric power to the emergency bus. The effect on decay heat removal and makeup is essentially the same for loss of power or loss of component cooling. However, the effect on the plant is in general much less severe for loss of component cooling versus loss of AC power. The support system event tree is quantified once for each unique impact of the initiating events on the support systems. The transient response event trees are then quantified for each of the four support system states for each initiating event.

There are two plant response event trees which model the response of the front line systems to the various initiators. The shutdown transient tree models the plant response to loss or degradation of decay heat removal and/or primary system overpressurization. The shutdown LOCA tree models the response to LOCAs that may occur as a result of an operator error during shutdown or due to overpressurization events in the shutdown transient tree where the pressure relief valves have failed. These trees are described in more detail in Section 3.4 (Transient tree) and Section 3.5 (LOCA tree).

The end states of the transient and LOCA tree sequences are either stable states with no damage or severe core damage plant damage states. Table 3-1 provides a definition of each plant damage state in terms of RCS pressure at the time of core melt (high or low), reactor cavity condition (wet or dry) and status of containment (isolated, penetrations open, hatch open). All the accident sequences ending in a core damage condition are mapped to one of the nine plant damage states. These states are then used in the determination of offsite consequences. See Section 10.1.2 for the basis for the plant damage states.

3.2 Initiating Events

Table 3-2 summarizes all the initiating events quantified in the plant model. A much larger list of initiating events was considered, but many were screened out based on comparisons of frequency and impact. The point estimate frequency and description is provided for each initiating event. The frequency distribution for each event is presented in the report section where the quantification is documented, as listed on Tabl 3-2. As discussed previously, four categories of initiating events are included in the plant model:

- o Support system failures
- o Internal/external hazards events
- o Procedure-initiated LOCAs
- o Procedure-initiated transients

The modeling of each initiating event is discussed in Sections 3.2.1 through 3.2.4. Section 3.2.5 discusses initiating events which were evaluated but not included in the plant model.

3.2.1 Support System Failure Initiating Events

Systems whose failure result in loss of decay heat removal are considered initiators in this shutdown study. The initiators in this section involve hardware failures of systems which support RHR. Hardware failures of the RHR system itself are modeled in the procedure event trees (see Sections 3.2.3 and 3.2.4).

Each initiator is divided into two groups based on the RCS condition present when the failure occurs. This is done in order to properly model the plant and operator response to the event. The RCS conditions are designated as follows:

X = RCS drained to the vessel flange or hot leg mid-plane and RCS vented.

W = RCS filled and closed with secondary cooling available via at least two steam generators.

The other possible RCS condition during shutdown, with the vessel head off and flooded to the fueling level (Y), is not included here because loss of RHR with the water level at refueling leve' would have to persist for on the order of days to result in core damage.

The following support system failures are modeled as initiators:

LOSP - Loss of offsite power. This initiator requires the diesel generators to start and the normally operating systems to restart and run. While loss of offsite power by itself does not cause loss of decay heat removal, it does put the plant in a somewhat degraded configuration with regard to core cooling.

LPCCA - Loss of primary component cooling water train A. The plant is modeled with RHR train A as the normally operating train. Loss of PCC train A results in loss of RHR pump cooling and loss of cooling to the RHR heat exchanger. This requires the operator to shift to the standby train (B) of RHR if available or to go to an alternate means of long term cooling - steam generator cooling (for RCS Condition W) or feed a-d bleed (for RCS Condition X).

LSWA - Loss of service water train A. This event includes the unavailability of train A of the cooling towers. This event results in loss of cooling to the train A PCC heat exchanger and thus is modeled as initiator LPCCA above. Service water train A also cools the diesel generator heat exchanger. However, offsite power is assumed to be available for this event and, thus, the diesels are not required to operate.

LPCC - Loss of both primary component cooling water trains. This results in loss of both trains of RHR and requires an alternate means of long term cooling that does not require PCC. For RCS Condition W, long term cooling involves steam generator cooling. For RCS Condition X, gravity draining of the RWST is modeled to provide core cooling.

LOSW - Loss of both trains of service water. This initiator includes unavailability of both trains of the cooling tower. Loss of service water results in loss of PCC and, thus, is modeled as initiator LPCC.

3.2.2 Internal/External Hazards Events

Loss of decay heat removal due to hazards internal or external the plant are described below. As with support system failure initiators, these events are also divided into two groups, based on the RCS Condition: X - RCS drained, W - RCS filled.

FLSW - External flood causing loss of all service water. This flood, due to low probability meteorological conditions, results in failure of equipment in the service water pump house and cooling tower. The accompanying storm is assumed to result in loss of offsite power. This causes loss of all RHR and requires alternate means of long term cooling.

TCTL - Truck crash into the SF_6 transmission lines. This event causes loss of offsite power which would be unrecoverable (within the 24 hour mission time). This initiator is modeled the same as LOSP except for the electric power recovery model.

FSGA - Fire in switchgear room A. This event causes loss of the essential 4160 Vac Bus E5, which results in loss of the operating RHR train. The operator must start the standby RHR train if operable or begin some alternate means of cooling.

FCRAC - Fire in the control room causing loss of all AC power. In addition to the fire in the control room, this event includes the failure of the operators to maintain core cooling from outside the control room. This event results in loss of RHR and loss of alternate cooling options due to operator error.

FETC - Fire in the electrical tunnel above the RHR vault. This fire causes loss of both trains of RHR and loss of one train of PCC and Service Water.

FETB - Fire in the electrical tunnel train B, causing loss of suction to the operating RHR train A (hot short) and loss of train B of Service Water. This results in loss of both RHR trains and requires an alternate cooling method.

FPCC - Fire in the PAB causing loss of both trains of PCC. This results in loss of both trains of RHR and is modeled like initiator LPCC.

FT''P - Fire in the turbine building causing loss of offsite power. This loss in unrecoverable (within 24 hours) and is modeled like initiator TCTL.

FPAB - Fire in the PAB causing loss of both trains of Service Water and one train of PCC. This results in loss of all RHR and requires alternate cooling methods.

FLRHR - Flood in the RHR vault due to a leak in an RHR train. This event results in the failure of both RHR trains and requires alternate cooling methods.

FLISG - Flood in the turbine hall due to circulating water pipe break. This results in loss of offsite power and leaks into switchgear room A causing failure of essential bus E5. The offsite power loss is assumed to be unrecoverable. The operator must start the standby RHR train (B) or use some alternate cooling method.

SSBO - Seismic station blackout. This event is a seismic event which causes loss of offsite power with subsequent seismic or hardware failure of the diesel generators. No alternate cooling method is modeled because of the difficulty of operator action.

SLL - Seismic large LOCA and loss of offsite power. This seismic event causes large displacements of the RCS components (e.g., steam generators) resulting in a large LOCA. This event is assumed to be a core melt because no credit is taken for manual initiation of low pressure injection. This event is modeled only with the RCS in Condition W (full). When the RCS is drained (X), the LOCA is not important because only a small amount of primary inventory would be lost.

3.2.3 Procedure-Initiated LOCAs

Six initiating events were identified (in addition to SLL above) which result in substantial loss of primary inventory. These events can occur only in RCS Condition W (full) or Y (refueling). As described above, LOCAs are not modeled in RCS Condition X (drained).

Li(W) - LOCA through a stuck-open RHR relief valve. This event is due to an overpressurization of the RCS-RHR systems and the operator failing to terminate the overpressure condition or the relief valve sticking open. The overpressure event is initiated in the Procedure event trees (1, 5, and 6) and the operator response is modeled in the Transient tree. This LOCA initiator is quantified as a sequence through the procedural trees and then through the Transient tree.

This LOCA is small (3" diameter relief valve) and can occur only with RCS Condition W (overpressure can occur only when the RCS is closed). The RHR relief valve discharges to the PRT and from there to the containment sumps. The LOCA is assumed to make the operating RHR train inoperable because of the stuck-open relief. The decay heat removal options available are:

(1) if the LOCA is isolated, standby RHR train or steam generator cooling or feed and bleed;

(2) if the LOCA is not isolated, low pressure injection/recirculation.

LP(W) - LOCA through the RHR pump seal. This event is similar to LOCA Li except that in response to an overpressure condition the RHR relief valves failed to open. The RHR pump seals rupture as a result of the continued overpressurization. The LOCA is small (possibly very small depending on how the seal ruptures).

The leakage is into the RHR vault and thus is not available for recirculation. The LOCA is assumed to make the operating RHR train inoperable because of the seal leak. The decay heat removal options available are:

(1) if the LOCA is isolated, standby RHR train or steam generator cooling or feed and bleed;

(2) if the LOCA is not isolated, feed and bleed.

L3(W) - LOCA through RH-V33, the cavity discharge valve back to the RWST. This event is modeled to occur during the initial cooldown in Mode 4 when the operator switches to RHR. The event results from multiple operator errors and causes the RCS to depressurize into the RWST. If the LOCA is immediately isolated, the operator can remain on secondary cooling or go to feed and bleed cooling. If the LOCA is unisolated, feed and bleed cooling can be used for long term decay heat removal.

This initiator is the result of shutdown procedural errors but is handled outside of the procedure trees for simplicity.

L5(Y) - LOCA through refueling cavity seal ring. This event results in the refueling pool draining to the RCS vessel flange. The water from this LOCA goes to the containment floor and then to the sumps. Decay heat removal options include normal RHR cooling or feed and bleed cooling. This event occurs in procedural tree 3 during a refueling outage.

L6(Y) - LOCA through the cavity drain valve. This LOCA occurs during the fill of the refueling pool and occurs through a 2" diameter valve (SF-V81) inadvertently left open. If unisolated, the LOCA drains the RCS inventory down to the top of the vessel flange. The water from this LOCA goes to the containment floor and then to the sumps. The decay heat removal options available are: 2 of 2 trains normal RHR cooling or feed and bleed cooling.

LS(W) - LOCA through the sump isolation valves. This is a large LOCA (16" diameter sump valves) and results in depressurizing the RCS to the containment sumps. This LOCA involves failure of the check valve (CBS-V25 or V26), between the RHR suction and the containment sump, with the containment sump valve open for testing. This results in a LOCA through the standby RHR suction line (12" diameter) to the containment sump. If the leak is not isolated, the inventory could drain to or below the bottom of the RCS hot legs. The only decay heat removal option available is low pressure recirculation.

This event is also analyzed outside the procedure trees because it is independent of the other procedural events.

3.2.4 Procedure-Initiated Transients

Procedure-initiated transient initiators are end states of th procedure event trees, as shown in Section 4 and quantified in Section 5.5. These events include degradation or loss of RHR cooling and concurrent or independent overpressurization.

The procedure-initiated events are listed in Table 3-2 and the designators are defined in Table 3-3. The designators are a three letter code where:

- o the first letter defines the RCS condition present when the event occurs:

  W - RCS filled and closed; secondary cooling available using steam generators.

  X - RCS drained to the vessel flange or hot leg center line.

  Y - RCS open and filled for refueling.

- o the second letter defines the status of the RHR system:

  1 - operating RHR train and standby train are available;

  2 - operating RHR train available; standby train unavailable;

  3 - operating RHR train suction lost; standby train available,

  4 - operating RHR train suction lost; standby train unavailable;

  5 - operating RHR train unavailable; standby train available;

  6 - operating and standby RHR trains are unavailable.

- o the third letter defines the overpressure condition occurring in the procedural event:

  A - overpressurization with at least two relief paths;

  B - overpressurization with one relief path;

  C - overpressurization with no relief paths;

N - no overpressurization.

Note, with regard to RHR status, that the procedure trees model specific failure modes for each train. For the operating train (A), the procedure trees model hardware failure to start (in tree 1), hardware failure to run (in all 6 trees), and loss of pump suction (in all 6 trees). For the standby RHR train (B), the procedure trees model only hardware failure to start (in tree 1) and failure to realign after refueling (in tree 4). Other possible failure modes are handled as follows:

- o failure of either RHR train due to support systems is modeled in the Support Systems event tree and in the support systems failure initiating events;
- o planned maintenance of the B train is modeled in top event RR in the Transient and LOCA event trees;
- o failure for either train to continue to run during the transient and failure to restart and run following LOSP are also modeled in top event RR.

3.2.5 Initiating Events Excluded From Shutdown Study

The following initiating events were evaluated and were determined to be not applicable (i.e., cannot occur during shutdown) or were not explicitly included because of their estimated low frequency.

LOCAs

LOCAs are modeled at shutdown explicitly rather than implicitly as random initiated events. These LOCAs include those due to overpressurization events with either failure of relief valves to open (RHR pump seal leak) or failure of relief valves to reseat (relief valve LOCA). Overpressure events as well as other LOCAs are identified in the procedure initiated event model (Section 4). In addition, other internal/external causes of LOCA initiators are explicitly included in the model.

The "Mode 4 LOCA" issue (random RCS pipe breaks during hot shutdown), being addresses generically by the Westinghouse Owners Group, is considered an insignificant risk contributor in this study. The conservative bounding calculations below, assuming the same frequency of random large and small LOCAs as at power, indicate that the Mode 4 LOCA is not a significant risk issue.

The LOCA initiator can be divided into two general scenarios: pipe breaks inside containment (I/C) and outside containment (O/C). Inside containment the primary loop is RCS piping, the leak is (likely) not isolable, and the coolant lost out the break is collected in the containment sump for recirculation. Outside containment, the primary loop is RHR piping, the leak can be isolated from the primary loop by closing the RHR suction isolation valves and if the leak is not isolated the coolant is not available for recirculation. Thus, frequency of large LOCA initiated core damage scenario during Mode 4 can be estimated as follows:

$LL_{I/C}$ = FR(M4) * FR(LL) * [OP1 + INJ + REC1 [illegible]]

$LL_{O/C}$ = FR(M4) * FR(LL) * [OP1' + LC]

Where

FR(M4) = frequency of the plant in Mode 4 (per year)
= 5 shutdowns per year * 30 hours in Mode 4 per shutdown

= 150 hours per year in Mode 4

= 0.017 years in Mode 4 per year

FR(LL) = frequency of large LOCA due to random pipe break (assumed to be the same frequency as at power; assumed to be the same for RCS and RHR piping)

$\simeq 10^{-4}$ per year

OP1 = operator fails to diagnose LOCA and stop RHR pump(s)

$\simeq 10^{-2}$

INJ = failure of high pressure and low pre sure injection

$< 10^{-4}$

RECIRC = failure of both trains of low pressure recirculation

$\simeq 10^{-3}$

OP1' = operator fails to diagnose LOCA and isolate the leak (close RHR suction valves) and trip the RHR pump

$\simeq 10^{-2}$

LC = failure of low term cooling (secondary cooling, normal RHR cooling, feed and bleed)

$< 10^{-4}$

Thus the frequency of large LOCA is on the order of 10^{-8} per year.

Similarly for small LOCA the frequency of a core damage scenario during Mode 4 can be estimated as follows:

$SL_{I/C}$ = FR(M4) * FR(SL) * [OP2 + INJ + RECIRC]

$SL_{O/C}$ = FR(M4) * FR(SL) * [OP2' + LC)

Where

FR(SL) = frequency of small LOCA (same as at power)

$\simeq$ 6.0E-3

OP2 = operator fails to diagnose small LOCA and stop RHR pump(s) - more time available than for OP1 (LL)

$\simeq 10^{-3}$

OP2' = operator fails to diagnose small LOCA and isolate leak and trip the RHR pump

$\simeq 10^{-3}$

Thus, the frequency of small LOCA is on the order of 10^{-7} per year. These scenarios are clearly dominated by operator action to diagnose the LOCA and initiate corrective action. The operator failure estimates assume considerable improvements in procedures and training due to NRC and Westinghouse Owner's Group efforts and consistent with the recommendations made in this study for the explicitly identified LOCAs.

Steam Generator Tube Rupture

Although steam generator leaks could conceivably occur during shutdown, they would not cause a transient condition while operating on RHR due to impossibility of reactor trip and reduction or reversal of pressure differentials.

Reactor Trip and Turbine Trip

These events cannot occur during shutdown by definition.

Loss/Excess Feedwater, Loss of Condenser Vacuum, Closure of MSIVs, Steam Line Breaks, Loss of Primary Flow

These events are not applicable during shutdown because the primary system is at low pressure, reactor coolant pumps are stopped, MSIVs are closed, etc.

Inadvertent Safety Injection

During shutdown, it is possible to get an inadvertent safety injection which could cause a cold overpressurization condition in the RCS. This inadvertent SI can be of two general types. (1) The more likely event consists of one charging pump injecting at maximum flow with isolation of letdown. This event requires only an inadvertent SI signal which can occur either during initial shutdown, if the SI signals are not blocked, or during the outage due to a maintenance error. The inadvertent safety injection due to SI not blocked can occur only in Mode 3 at 1875 psig, with full ECCS available. This event is modeled conservatively by inadvertent SI during power operation. The inadvertent safety injection due to maintenance error is considered a source of excess charging and is included in Top Event NC in procedure tree. (2) The less likely event consists of several high pressure pumps (SI or charging pumps) injecting and results in a more severe challenge to the RCS. However, the operators have explicit procedures and Technical Specification requirements to disable both SI pumps and one charging pump when in Modes 5 and 6. For several high pressure pumps to inadvertently inject and challenge the RCS requires the following very unlikely series of failures (with estimated frequency of each):

(a) Inadvertent SI signal received during shutdown (assume 1/year).

(b) Operators fail to put switches for the three pumps in "pull to lock" per shutdown procedure (3 * 0.001).

(c) Operators fail to remove power to pumps by racking out breakers in switchgear rooms per procedure. Technical Specifications require action within 4 hours of entering Mode 4. Verified once per 31 days (3 * 0.01).

(d) Next operating crew fails to observe the pump control switch light on (0.1) or light burns out (small).

(e) Multiple (two or more) relief valves fail (assume common cause beta factor = 0.125) (0.125 * 4E-3).

The frequency of this initiating event (inadvertent full SI and failure of relief) is estimated at approximately 5E-9/yr, which is negligible.

Instrument Tube LOCA

Incore instrument tubes were considered as potential sources of loss of coolant accidents. The instrument tubes are welded to the vessel and are run to the seal table, which is at the level of the vessel flange. The tubes are an RCS boundary and are designed and supported as such, including considerations of Seismic I/II analyses. Based on this design, the frequency of tube rupture is considered to be negligible.

A leak of the swage lock connection in the seal table would result in a very small leak (0.35" I.D.) which would be alarmed via radiation monitors. If the leak was unattended or if a number of connections failed, the RCS level could not drain below the vessel flange. This is judged to be low in frequency and relatively insignificant in consequences.

Reactor Coolant Pump Seal LOCA

Significant leakage out the reactor coolant pump seals occurs only in the presence of high temperature reactor coolant, which degrades the elastomer seals, and high primary pressure, which forces fluid past the degraded seals. During shutdown, the reactor coolant temperature is normally less than 300°F with low (< 50 psig) primary pressure. Thus, conditions are not normally present during shutdown which would result in a pump seal LOCA. During a loss of heat removal scenario, the coolant temperature will increase until the coolant boils. When the temperature is high enough to threaten the seals, the primary inventory will have boiled away to just above the top of the core. Thus, a seal failure would have no effect in the course of the accident.

Boron Dilution and Recriticality

Recriticality was judged to be an insignificant contributor to risk during shutdown because of the controls that prevent boron dilution, the possibility of operator action to terminate recriticality early, and the minor consequences of recriticality.

Boron dilution is prevented by limiting the maximum inadvertent addition of unborated water. Technical Specifications require: the Boron Thermal Regeneration System (BTRS) to be isolated from the RCS; the Reactor Makeup Systems to be inoperable except for one pump; and the primary coolant boron concentration to be monitored daily.

If boron dilution were to occur, the onset to recriticality would be detected (and alarmed) by either of the redundant shutdown monitor channels and/or by one or more of the redundant source range neutron detectors. Operators have emergency procedures and are trained to respond to this condition. Technical Specifications require that a boration path (RWST - charging pump or BAST - transfer pump) be available. At the point of the alarms, the operator has at least 15 minutes (based on conservative licensing assumptions) to increase the RCS boron concentration.

If there were no operator actions to terminate this event, reactor power would increase slowly. This would increase both fuel and moderator temperature until boiling in the core is reached. Boiling would increase until there is sufficient neutron leakage to prevent any additional power increase.

Thus, equilibrium power level reached in the core will depend on and be limited by the heat removal capability of the RHR. Heat fluxes developed in the core will be small. The core will continue to be cooled for an even longer period of time.

Because of the very slow rates of reactivity addition possible via dilution and the long periods of time needed to postulate no operator actions, these events which have very low risk significance while at power, have essentially no risk significance at shutdown.

3.3 Support Systems Tree

Support system failures can affect multiple systems thereby representing a potential dependent failure mechanism. For this reason a support system event tree (Figure 3-2) is used to explicitly model support system dependencies consistent with the SSPSA (Reference 1) methodology.

Given a demand (initiating event) for plant response (plant response trees), the support system event tree model analyzes the status of key plant support systems that are necessary to support operation of the front line systems. Three key support systems, AC power, service water, and primary component cooling, are modeled. These support systems were the most important in the SSPSA as well as this study. Four support system endstates are defined in the event tree:

Support State	Description
FO	All support systems available
FA	Train A support systems unavailable
FB	Train B support systems unavailable
FAB	Both trains of support systems unavailable

The FABR1 and FABR2 endstates in Figure 3-2 denote AC power configurations which are potentially recoverable. Electric power recovery is considered on a sequence by sequence basis as discussed in Section 2.

As shown in Figure 3-2, failure of any single system train is modeled as a complete loss of support systems in the same train. This simplifies the number of endstates and is not overly conservative because the important "mainline" systems in the shutdown transient tree and the shutdown LOCA tree require both service water and primary component cooling for success. These mainline systems are RHR (top event RR) and charging pumps (top event LC).

When the initiating event includes a loss of offsite power, emergency AC power (top events GA and GB) dominates the unavailability of a support train. Therefore, the simplified endstates are not overly conservative, even though PCC failure is modeled as loss of a support train but actually does not fail service water or emergency AC. In the case where offsite AC power is available, emergency AC power is assumed to be successful (GA and GB are not questioned). Based on results from the SSPSA, loss of offsite AC and emergency AC or emergency buses during the 24 hour mission time is unlikely.

Dependencies between support systems are explicitly modeled in the support system tree (Figure 3-2) by passing through the top event-guaranteed failure (GF). As shown, primary component cooling Train A is dependent on Service Water Train A and AC power Train A. Also Service Water Train A is dependent on AC power Train A. The same is true for Train B.

The endstate definition distinguishes between Train A and Train B failures (endstate FA and FB). In order to correctly track RHR status through the model, it is assumed that Train A RHR is always the operating train and Train B is in standby. This assumption is made to simplify the modeling and is made based on the symmetry between RHR trains. Therefore, initiating events entering the support system tree will be tracking the status of the operating train and the standby train.

Dependencies between initiating events and support system tree top events are addressed in the model quantification in Section 5. The event tree top events are described below:

Top Event GA: Emergency AC Train A

This top event quantifies the frequency of failure of emergency AC power Train A (diesel generator A) for initiating events resulting in loss of offsite power. Failure of this top event guarantees failure of Train A service water and primary component cooling for loss of offsite power initiators. For initiating events which do not result in loss of offsite power, this event is not questioned (guaranteed success). Loss of offsite over 24 hour mission time and failure of a diesel or failure of the emergency bus is unlikely in comparison to other support systems.

Top Event GB: Emergency AC Train B

This top event quantifies the frequency of failure of emergency AC power Train B for initiating events resulting in loss of offsite power. The effects of failure of this top event are similar to top event GA.

Top Event WA: Service Water Train A

This top event quantifies the frequency of failure of service water Train A. Failure of this top event results in failure of Train A primary component cooling.

Top Event WB: Service Water Train B

This top event quantifies the frequency of failure of service water Train B. Failure of this top event results in failure of Train B primary component cooling.

Top Event PA: PCC Train A

This top event quantifies the frequency of failure of primary component cooling (PCC) Train A. This event is guaranteed to fail and is not asked if event GA or event WA fails.

Top Event PB: PCC Train B

This top event quantifies the frequency of failure of primary component cooling (PCC) Train B. This event is guaranteed to fail and is not asked if event GB or event WB fails.

3.4 Shutdown Transient Tree

The Shutdown Transient Tree is used to model the response of plant systems and operators to initiating events involving loss of RHR cooling, loss of RHR suction, and/or an RCS overpressure condition (non-LOCA events). Initiating events of this type include internal and external initiators as well as procedure initiated events from the Procedure Event Trees. Table 3-2 provides a summary of the initiating events quantified in this study and identifies the specific initiators for which the Shutdown Transient Tree is used to model the plant response.

Figure 3-3 shows the event sequence diagram used to assess the plant systems and operator response to a (non-LOCA) transient condition in the plant. Following a discussion of this diagram, the more detailed event tree will be described.

Briefly, the flow of events in Figure 3-3 is as follows. Given the occurrence of an initiating event, block 1 questions whether an RCS overpressure condition exists, and if it does, blocks 2 and 3 assess the response to this condition. Block 4 questions whether suction is available to the operating RHR pump and if not, block 5 questions whether the operator trips the pump before it fails. Block 6 asks whether the operator correctly assesses the plant situation (assuming RHR cooling has been lost) and what recovery action should be taken. If the operator is successful in block 6, blocks 7 and 8 are used to determine whether RHR cooling or alternate core cooling is subsequently established. If the operator fails in block 6, or if blocks 7 and 8 fail, core damage is assumed to occur. If core damage occurs, block 9 questions whether the equipment hatch is closed prior to significant release. Block 10 questions whether other smaller containment openings are closed prior to release. If block 9 fails, a R2H or R6H plant damage state (PDS) occurs and if block 10 fails, a R2P or R6P PDS occurs. If blocks 9 and 10 are both successful, a R2D or R6D PDS occurs. Table 3-1 describes plant damage states.

Additional information on the events represented by blocks 1 through 10 is provided below.

Block 1

After the initiation of a non-LOCA transient, block 1 questions whether an RCS overpressure condition exists at the start of the transient. If pressure is controlled, then no RCS overpressure condition exists. This block will either be a guaranteed success or a guaranteed failure, depending only on the procedure initiating event being analyzed. Since none of the internal or external hazard events (e.g., fires) were found to cause an overpressure condition, this block is guaranteed to be successful for all internal and external hazard events.

Blocks 2 and 3

If block 1 fails (i.e., overpressure condition exists), then blocks 2 and 3 are asked to assess the plant response to the overpressure condition. If block 1 is successful, blocks 2 and 3 are not asked because there is no overpressure condition. Block 2 asks whether the relief valves open to mitigate the overpressure condition. If block 2 fails, it is assumed that the pump seal on the operating RHR pump will rupture due to overpressurization and a LOCA results. This plant condition is then further analyzed in the LOCA Event Tree. If block 2 is successful, block 3 is used to question whether the operator corrects the cause of the overpressure condition and whether the relief valves close after opening in block 2. If block 3 fails, it is assumed that the relief valves remain open and a LOCA condition results. This plant condition is further analyzed in the LOCA Event Tree. If block 3 is successful, the overpressure condition has been corrected and the plant response continues with block 4.

Blocks 4 and 5

Block 4 questions whether suction is available to the operating RHR pump. Similar to block 1, this block will either be guaranteed to succeed or guaranteed to fail depending on the initiating event being analyzed. If suction is not available, and the RHR pump is running, it is assumed that the pump will fail unless the operator trips the pump within 30 minutes based on experience events. Block 5 is used to question whether the operator trips the pump within 30 minutes to prevent pump failure and is asked only if block 4 fails.

Block 6

Block 6 questions whether the operator is able to correctly assess conditions in the plant and identify actions to be taken to avoid core damage. If a loss of RHR cooling transient or a loss of RHR suction transient has occurred, the operator must assess what actions to take to restore core cooling. If an overpressure transient is being analyzed, no operator action is required in block 6 since blocks 1, 2, and 3 previously analyzed the possible plant/operator responses to the overpressure condition where failures transfer to the LOCA tree. If block 6 fails, it is assumed that core damage will result due to lack of core cooling. If block 6 is successful, blocks 7 and 8 are used to determine whether the operators correctly implement actions required to restore core cooling.

Blocks 7 and 8

Block 7 questions whether RHR cooling is restored. For most initiating events, the primary means of restoring core cooling is to re-establish RHR cooling using either the previously operating RHR pump or the standby pump. In some cases however, both RHR pumps may be unavailable or may fail to start or run for the required mission time. In these cases (i.e., if block 7 fails) it is assumed that the operator will attempt to initiate alternate means of core cooling. The basis for this assumption is that the prior success of block 6 (operator identifies recovery action) implies the operator has correctly assessed the plant situation and will therefore respond correctly if RHR cooling cannot be restored. If block 7 is successful RHR cooling is restored and the plant conditions are stabilized with no core damage.

Block 8 asks whether alternate means of core cooling are established if RHR cooling cannot be restored. This block is reached only if block 7 has failed. Alternate means of core cooling consist of (1) using steam generators (if available) to remove core heat, (2) using charging or SI pumps to feed the RCS and bleeding off excess inventory through RCS openings or the pressurizer PORV, or (3) draining the RWST inventory (by gravity) into the RCS if plant conditions permit (modeled only for no support systems available). If one or more of these alternate core cooling methods is successful, the plant conditions are stabilized with no core damage. If alternate core cooling is not established (block 8 fails), core damage is assumed to occur.

Blocks 9 and 10

Blocks 9 and 10 are questioned only if core damage has occurred due to loss of cooling. This condition is represented in Figure 3-3 by either failure of block 6 (operator fails to identify correct actions to restore core cooling) or failure of blocks 7 and 8 (RHR cooling and alternate core cooling is not established and maintained). Block 9 questions whether the equipment hatch is closed prior to a significant release. If this block fails, a large release results (PDS R2H or R6H). (See Section 10 for definition of release categories). If block 9 is successful, block 10 asks whether small containment penetrations are closed prior to release. If block 10 fails, a small release results (PDS R2P or R6P) and if block 10 is successful, no release results (PDS R2D or R6D). Note that if block 9 fails (i.e., equipment hatch is not closed before release) it is not necessary to question block 10 because the successful closing of small containment penetrations will be of little consequence if the containment equipment hatch is not closed.

Figure 3-4 contains the Shutdown Transient Event Tree. In this tree, the top events correspond to the blocks in Figure 3-3 as follows:

Block 1 -> Top Event PC, RCS Pressure Controlled
Block 2 -> Top Event VO, Relief Valve Opens
Block 3 -> Top Event OC, Operator Stops Overpressure
Block 4 -> Top Event SA, RHR Suction Available
Block 5 -> Top Event TP, Operator Trips RHR Pump
Block 6 -> Top Event OR, Operator Identifies Action
Block 7 -> Top Event RR, RHR Restored
Block 8 -> Top Event LC, Alternate Long Term Cooling
Block 9 -> Top Event EH, Equipment Hatch Closed

Block 10 -> Top Event SP, Containment Small Penetrations Isolated

In the event tree, sequences 1 through 8 represent transients in which no overpressure condition exists (top event PC is successful), and no loss of suction exists (top event SA is successful), so that the transient consists only of loss of RHR cooling. In sequence 1 the operator correctly identifies actions to be taken (top event OR is successful) and RHR cooling is restored (top event RR is successful) leading to a stable plant state. Sequence 2 is similar to sequence 1 except that RHR cooling is not restored (top event RR fails) but alternate core cooling is restored (top event LC is successful) leading to a stable plant state. In sequences 3 through 5 the operator correctly identifies actions to be taken to restore core cooling but top events RR and LC both fail, leading to core damage. In sequence 3 the equipment hatch is closed and small penetrations are secured prior to release (top events EH and SP are successful). In sequence 4 the equipment hatch is closed but small penetrations are not secured prior to release (top event EH is successful, top event SP fails). In sequence 5 the equipment hatch is not closed prior to release (top event EH fails, top event SP is not asked). Sequences 6 through 8 result in the same release types as sequences 3 through 5. In sequences 6 through 8 core damage results due to failure of the operator to correctly identify actions to be taken to avoid core damage (top event OR fails).

Sequences 9 through 16 are the same as sequences 1 through 8 except that in sequences 9 through 16 a loss of RHR suction resulted from the initiating event (top event SA failed) and the operator successfully tripped the RHR pump before it failed due to operating with loss of suction (top event TP was successful).

Sequences 17 through 24 are the same as sequences 9 through 16 except that in sequences 17 through 24 the operator fails to trip the RHR pump before it fails due to cavitation from loss of suction (top event TP fails).

Sequences 25 through 48 are the same as sequences 1 through 24 except that in sequences 25 through 48 an RCS overpressure condition existed due to the initiating event (top event PC failed) and was successfully mitigated (top events VO and OC were successful).

Sequences 49 and 50 represent transients in which an overpressure condition exists due to the initiating event and is not successfully mitigated, leading to a LOCA. In sequence 49 the RHR relief valves fail to open (top event VO fails) leading to a LOCA resulting from overpressurization and failure of the RHR pump seal. In sequence 50 the relief valves open but do not close, or the operator fails to correct the cause of the overpressure condition (top event OC fails) resulting in a LOCA from the RHR relief valves.

3.5 Shutdown LOCA Tree

The Shutdown LOCA Tree is used to model the response of plant systems and operators to LOCA initiating events. These events are identified in Table 3-2 which provides a summary of all initiating events considered.

Figure 3-5 shows the event sequence diagram used to assess the plant systems and operator response to a LOCA. Following a discussion of this diagram, the more detailed event tree is described.

In Figure 3-5, blocks 1 through 4 represent actions which take place in the short term (0-30 minutes) after the LOCA occurs. Blocks

5 through 9 represent long term responses (beyond 30 minutes). The division between short and long term responses is based on assuming (1) the operating RHR will fail if not tripped by the operator within 30 minutes of losing suction (short term response), and (2) early successful isolation will allow normal RHR cooling to continue. Note that blocks 5 through 9 in Figure 3-5 are similar to blocks 6 through 10 in Figure 3-3.

Briefly, the flow of events in Figure 3-5 is as follows. Given the occurrence of a LOCA, block 1 questions whether the operator detects the condition. If block 1 is successful block 2 questions whether the leak (if in the RHR cooling loop) is isolated by closing the RHR suction valves. If the leak is not in the RHR cooling loop, block 2 is assumed to fail because it is assumed that in the short term the operator will fail to identify the leak location. If block 2 is successful, block 4 questions whether the operator trips the operating RHR pump to prevent failure of the pump due to loss of suction. If block 2 fails, block 3 questions whether makeup flow is established. Success of block 3 results in additional time being available for subsequent operator actions. Whether block 3 is a success or failure, it is assumed that the operator must trip the operating RHR pump to prevent failure due to vortexing (i.e., it is assumed that even if makeup flow is established, the RHR pump will have suffered loss of suction due to initial loss of RCS inventory). If the operator fails to initially detect the LOCA (block 1 fails) it is assumed that blocks 2, 3, and 4 all fail resulting in loss of the operating RHR pump.

Block 5 asks whether the operator correctly assesses the plant situation (following any combinations of success and failure of blocks 1 through 4) and what actions should be taken to restore long term core cooling. If block 5 is successful, blocks 6 and 7 are used to determine whether RHR cooling or alternate core cooling is subsequently established. If the operator fails in block 5, or if blocks 6 and 7 fail, core damage occurs. If core damage occurs, block 8 questions whether the equipment hatch is closed prior to release and block 9 questions whether other, smaller containment openings are closed prior to release. If block 8 fails, a R1H, R2H or R6H plant damage state (PDS) occurs. If block 9 fails, a R1P, R2P or R6P PDS occurs. If blocks 8 and 9 are both successful, a R1D, R2D or R6D PDS occurs. Table 3-1 describes plant damage states.

Additional information on the events represented by blocks 1 through 9 is provided below.

Block 1

After a LOCA occurs block 1 questions whether the operator detects the condition within 30 minutes. It is assumed that failure to detect the LOCA within this short time interval will result in RCS inventory loss sufficient to cause loss of suction to the operating RHR pump. Also, failure of block 1 is assumed to result in failure to establish short term makeup flow (block 3) and failure of the operator to trip the RHR pump (block 4), thereby causing failure of the operating RHR pump. If block 1 fails, the next block questioned is block 5 (operator identifies action to establish long term cooling prior to core damage) and no oportunity for restoring RHR (block 6) is allowed. If block 1 is successful, block 2 is questioned.

Block 2

Block 2 asks whether the operator isolates the LOCA within 10 minutes after it occurs. It is assumed that this block will fail if the LOCA is not in the RHR cooling loop because LOCAs in other locations would be difficult to locate in this short time period. Given a LOCA of unknown origins, the operator would most likely initially assume it was in the RHR cooling loop and would isolate RHR. If block 2 is successful, the LOCA is in the RHR cooling loop and the leak is isolated by closing the RHR suction valves. Under this condition, suction will be lost to the operating RHR pump and the operator must trip the pump to prevent pump failure (see block 4). If block 2 fails, RCS inventory continues to be lost due to the leak and restoration of normal RHR (block 6) is guaranteed to fail.

Block 3

If the operator detects the LOCA (block 1 is successful) and the leak is not isolated (block 2 fails), block 3 questions whether the operator establishes makeup flow to the RCS within 30 minutes after the LOCA occurs. Success of this action provides the operator with additional time to complete the subsequent corrective actions represented by blocks 4 and 5. Failure of this action requires more rapid operator responses for success in blocks 4 and 5. Note in Figure 3-5 that whether block 3 is successful or failed, block 4 (operator trips RHR pump) is asked because it is assumed that initial RCS inventory loss is sufficient (with or without makeup flow) to cause loss of suction to the operating RHR pump.

Block 4

Block 4 questions whether the operator trips the operating RHR pump after suction has been lost due to loss of RCS inventory. It is assumed that whether blocks 1, 2, and 3 succeed or fail, RCS inventory loss results in loss of suction to the RHR pump, requiring action in block 4 to avoid pump failure.

If block 2 or block 3 is successful, the operator is more likely to trip the operating RHR pump than if blocks 2 and 3 both fail. If the operator fails to detect the LOCA (block 1 fails), block 4 is assumed to fail.

Block 5

Block 5 questions whether the operator is able to correctly assess conditions in the plant and identify actions to be taken to terminate the LOCA and avoid core damage. The time available for the operator to successfully complete this action is dependent on the type of LOCA initiator as well as previous success or failure of block 2 (operator isolates RHR) and block 3 (operator established makeup flow). If block 5 fails it is assumed that core damage will result due to loss of RCS inventory. If block 5 is successful, blocks 6 and 7 are used to determine whether the operators correctly implement actions required to establish long term core cooling.

Blocks 6 and 7

Blocks 6 and 7 question whether long term core cooling is established. Block 6 asks if RHR cooling is re-established, given success of blocks 1 and 2, and if successful, leads to a stable plant condition with no core damage. If RHR cooling cannot be re-established or maintained (block 6 fails) it is assumed that the operator will attempt to initiate alternate means of core cooling. The basis for this assumption is that the prior success of block 5 (operator identifies long term cooling options) implies the operator has c rrectly assessed the plant situation and will therefore respond correctly if RHR cooling cannot be restored.

Block 7 asks whether alternate means of core cooling are established if RHR cooling cannot be restored. This block is reached only if block 6 has failed. Alternate means of core cooling consists of (1) using steam generators (if available) to remove core heat, (2) using charging or SI pumps to feed the RCS and bleeding off excess inventory through the RCS or RHR relief valves, or (3) draining the RWST inventory (by gravity) into the RCS if plant conditions permit (modeled only for no support systems available). If one of these alternate core cooling methods is successful the plant conditions are stabilized with no core damage. If alternate core cooling is not established (block 7 fails), core damage is assumed to occur.

Blocks 8 and 9

Blocks 8 and 9 are reached only if core damage has occurred due to loss of long term cooling. This condition is represented in Figure 3-5 by either failure of block 5 (operator fails to identify options for long term core cooling) or failure of blocks 6 and 7 (RHR cooling and alternate core cooling is not established and maintained). Block 8 questions whether the equipment hatch is closed prior to release. If this block fails, a large release results (PDS R1H, R2H or R6H). If block 8 is successful, block 9 asks whether small containment penetrations are closed prior to release. If block 9 fails a small release results (PDS R1P, R2P or R6P) and if block 9 is successful no release results (PDS R1D, R2D or R6D). Note that if block 8 fails (i.e., equipment hatch is not closed before release), it is not necessary to question block 9 because the successful closing of small containment penetrations will be of little consequence if the containment equipment hatch is not closed.

Figure 3-6 shows the Shutdown LOCA Event Tree. In this tree, the top events correspond to the blocks in Figure 3-5 as follows:

Block 1 -> Top Event OD, Operator Detects LOCA
Block 2 -> Top Event IR, Isolate RHR
Block 3 -> Top Event MU, Makeup Flow Initiated
Block 4 -> Top Event TP, RHR Pump Tripped
Block 5 -> Top Event OL, Operator Identified Long Term Cooling Options
Block 6 -> Top Event RR, Normal RHR Restored
Block 7 -> Top Event LC, Alternate Long Term Cooling
Block 8 -> Top Event EH, Equipment Hatch Closed
Block 9 -> Top Event SP, Containment Small Penetrations Isolated

In the event tree, sequences 1 through 16 represent a LOCA in the RHR cooling loop which is detected by the operator (top event OD is successful) and isolated (top event IR is successful). In sequences 1 through 8, the RHR pump is tripped (top event TP is successful) and is therefore prevented from failing due to loss of suction while in sequences 9 through 16 top event TP fails, and the operating RHR pump is therefore assumed to fail. In sequences 1 through 16, top event MU is not asked because makeup flow is not needed when the LOCA is successfully isolated. In sequence 1 the operator successfully identifies long term cooling options (top event OL is successful) and normal RHR cooling is restored (top event RR is successful), leading to a stable plant state. Sequence 2 is similar to sequence 1 except that RHR cooling is not restored (top event RR fails) but alternate core cooling is restored (top event LC is successful) leading to a stable plant condition. In sequences 3 through 5 the operator correctly identifies long term cooling options (top event OL is successful) but top events RR and LC both subsequently fail, leading to core damage. In sequence 3 the equipment hatch is closed and small penetrations are isolated prior to release (top events EH and SP are successful). In sequence 4 the equipment hatch is closed but small penetrations are not isolated prior to release (top event EH is successful, top event SP fails). In sequence 5 the equipment hatch is not closed prior to release (top event EH fails, top event SP is not asked). Sequences 6 through 8 result in the same release types as sequences 3 through 5. In sequences 6 through 8 core damage results due to failure of the operator to correctly identify long term cooling options (top event OL fails), which guarantees failure of top events RR and LC.

Sequences 9 through 16 are identical to sequences 1 through 8, except that in sequences 9 through 16, the operating RHR pump has fail d due to failure of the operator to trip the pump after suction is lost (top event TP fails).

In sequences 17 through 30 the operator detects the LOCA (top event OD is successful), the RHR system is not isolated (top event IR fails), and makeup flow is initiated (top event MU is successful). In all of these sequences, top event RR is guaranteed to fail because failure to isolate the RHR system (failure of top event IR) is assumed to preclude restoration of a normal RHR alignment. Sequences 17 through 23 correspond to sequences 2 through 8 since the RHR pump is tripped before failure (top event TP is successful) and sequences 24 through 30 correspond to sequences 10 through 16 in which the operating RHR pump fails due to failure of top event TP.

Sequences 31 through 44 are identical to sequences 17 through 30 except that in sequences 31 through 44, makeup flow is not established (top event MU fails) after the operator detects the LOCA (top event OD is successful) and the RHR system is not isolated (top event IR fails). The failure to establish makeup flow in sequences 31 through 44 results in less time being available for the operator to be successful in completing top events TP (RHR pump tripped) and OL (operator identifies long term cooling options).

In sequences 45 through 50, the operator fails to detect the LOCA within 30 minutes after it occurs (top event OD fails). This failure is assumed to result in failure of the operator to isolate the RHR system (top event IR fails), failure to initiate makeup flow (top event MU fails), and failure to trip the RHR pump (top event TP fails). As a result of the failure of top event IR, it is assumed that restoration of normal RHR cooling is not possible, so top event RR is also guaranteed to fail. In sequences 45 through 48 the operator successfully identifies long term cooling options (top event OL is successful). In sequence 45 alternate long term cooling is established (top event LC is successful) and a stable plant condition is reached. In sequences 49 and 50 the operator fails to identify long term cooling options (top event OL fails). In these two sequences it is assumed that the operator will fail to attempt to isolate small containment penetrations (top event SP will fail), since the operator has previously failed to complete important actions (top events OD and OL have failed).

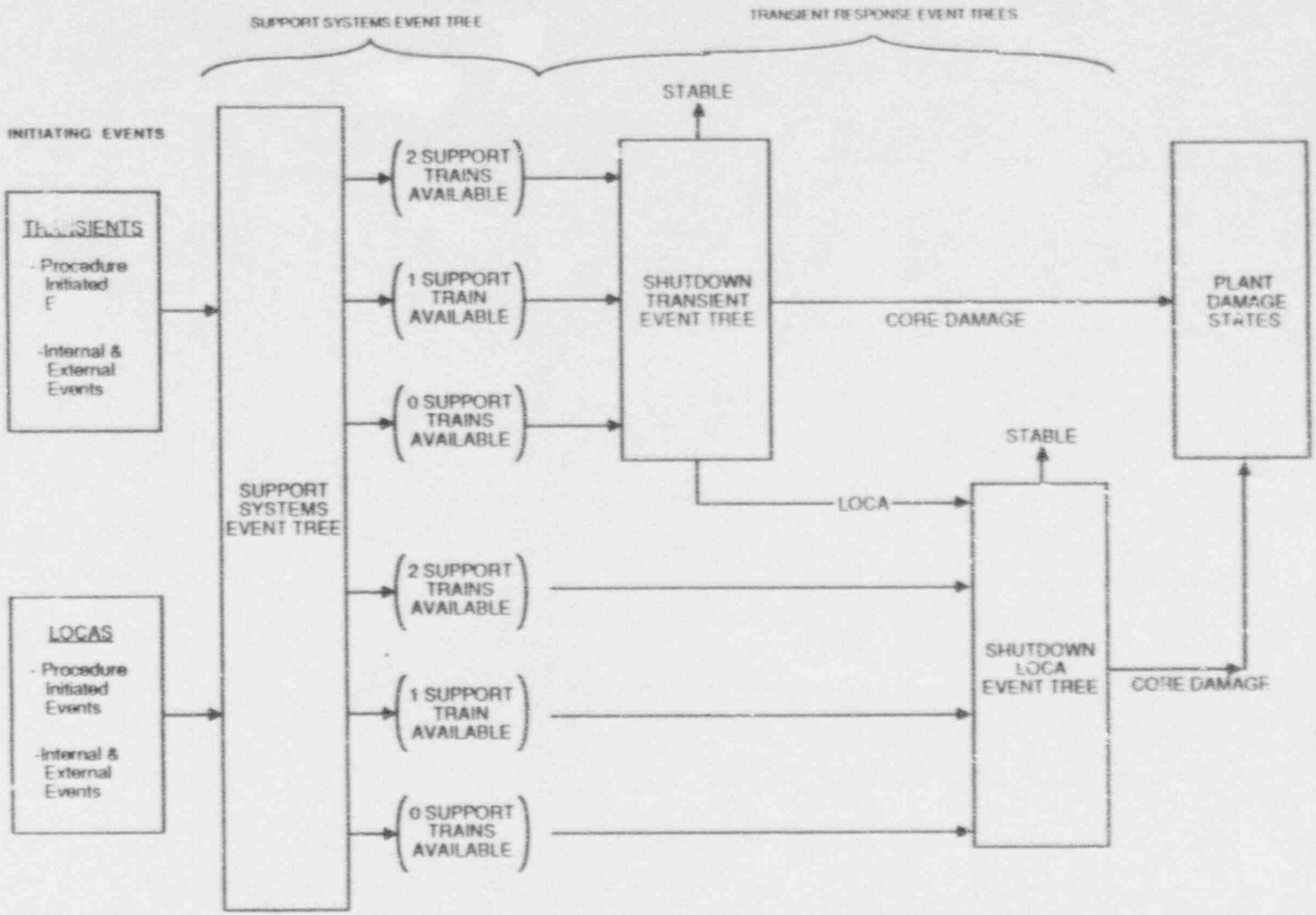
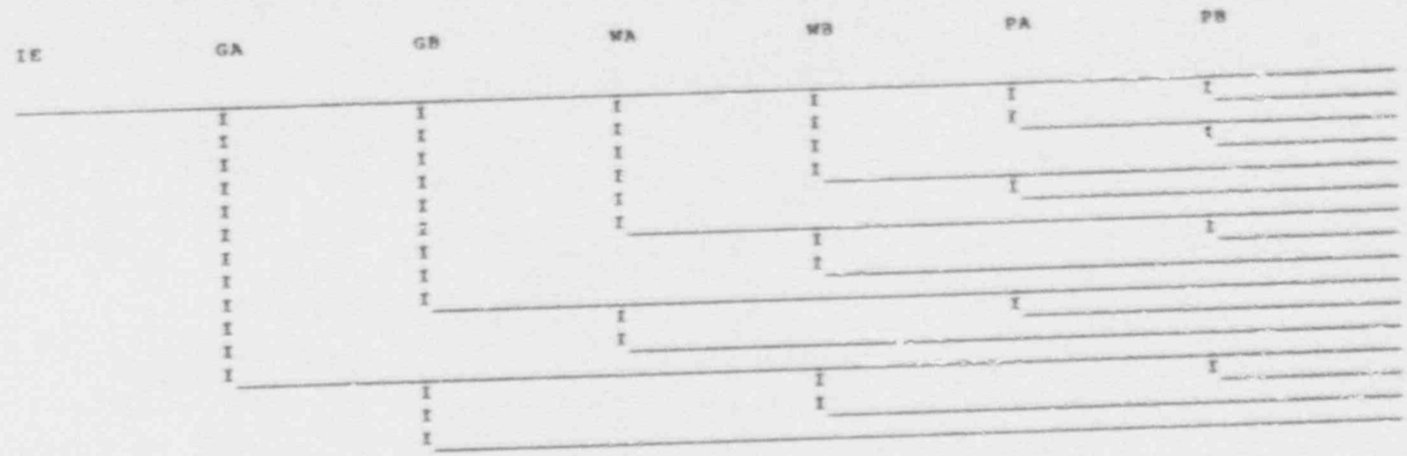


FIGURE 3-1 OVERVIEW OF PLANT EVENT SEQUENCE MODEL

FIGURE 3-2 SUPORT SYSTEMS TREE

EVENT	NAME OF EVENT
IE	INITIATING EVENT
GA	Electric Power Train A
GB	Electric Power Train B
WA	Service Water Train A
WB	Service Water Train B
PA	Primary Comp. Cooling Train A
PB	Primary Comp. Cooling Train B



SEQ	END STATE
1	0
2	FB
3	FA
4	FAB
5	FB
6	FAB
7	FA
8	FAB
9	FAB
10	FB
11	FABR1
12	FABR1
13	FA
14	FABR1
15	FABR1
16	FABR2

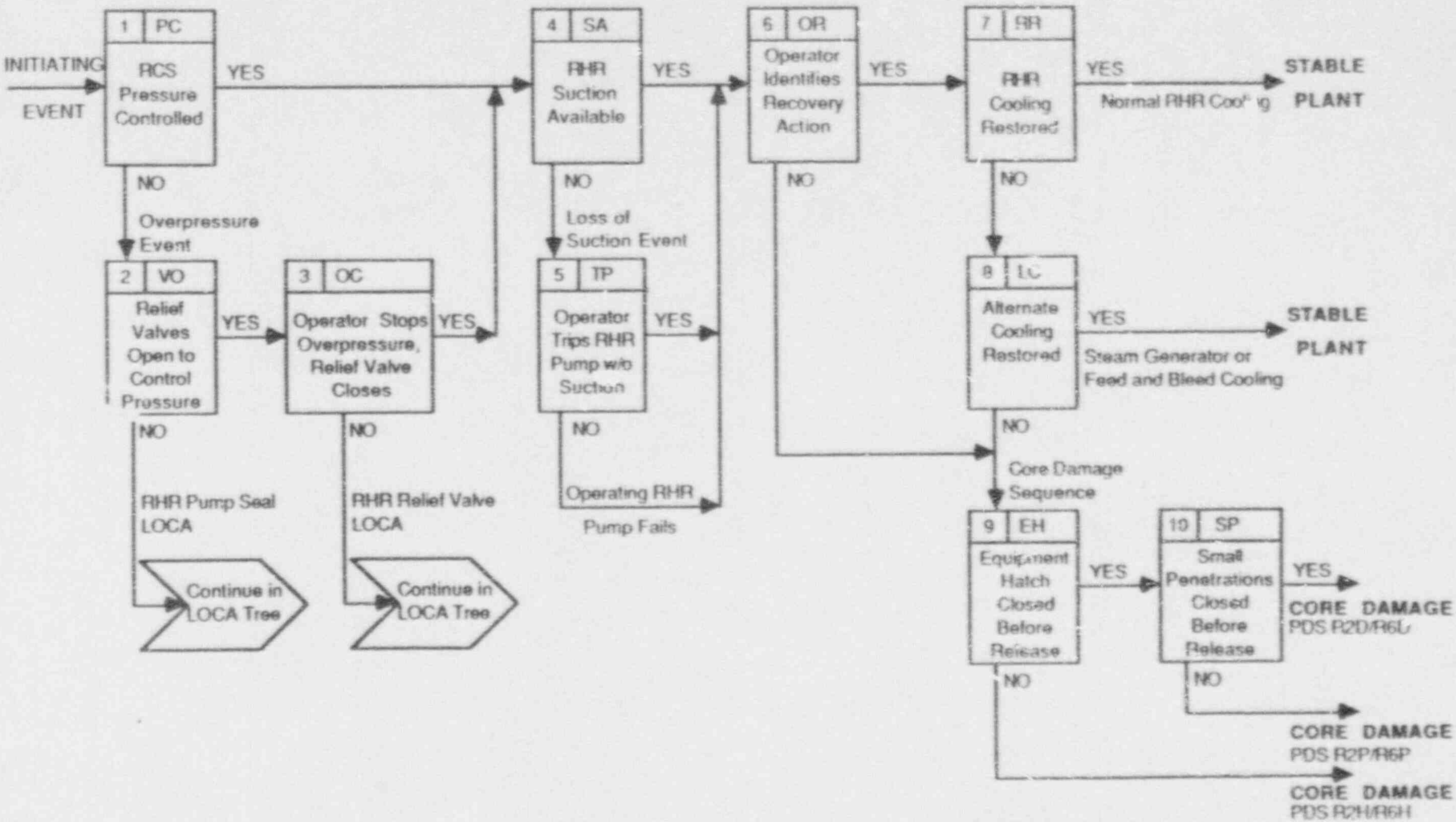


FIGURE 3-3 Event Sequence Diagram for Shutdown Transients

FIGURE 3-4 SHUTDOWN TRANSIENT TREE

EVENT	NAME OF EVENT		
IE	INITIATING EVENT	OR	Operator ID's recovery action
PC	RCS Pressure controlled	RR	RHR Heat removal restored
VO	RV Open and control pressure	LC	S.G. Cooling or Feed & Bleed
OC	RHR & Low pressure RV's close	EH	Eq. Hatch closed < release to Cmnt.
SA	RHR Suction available	SP	Small pen closed < release to Cmnt.
TP	Operator trips RHR pump		

SEQ	END STATE ~W	END STATE ~E
1	S	S
2	S	S
3	R6D	R2D
4	R6P	R2P
5	R6M	R2M
6	R6D	R2D
7	R6P	R2P
8	R6M	R2M
9	S	S
10	S	S
11	R6D	R2D
12	R6P	R2P
13	R6M	R2M
14	R6D	R2D
15	R6P	R2P
16	R6M	R2M
17	S	S
18	S	S
19	R6D	R2D
20	R6P	R2P
21	R6M	R2M
22	R6D	R2D
23	R6P	R2P
24	R6M	R2M
25	S	S
26	S	S
27	R6D	R2D
28	R6P	R2P
29	R6M	R2M
30	R6D	R2D
31	R6P	R2P
32	R6M	R2M
33	S	S
34	S	S
35	R6D	R2D
36	R6P	R2P
37	R6M	R2M
38	R6D	R2D
39	R6P	R2P
40	R6M	R2M
41	S	S
42	S	S
43	R6D	R2D
44	R6P	R2P
45	R6M	R2M
46	R6D	R2D
47	R6P	R2P
48	R6M	R2M
49	L1-ST	L1-ST
50	LP-ST	LP-ST

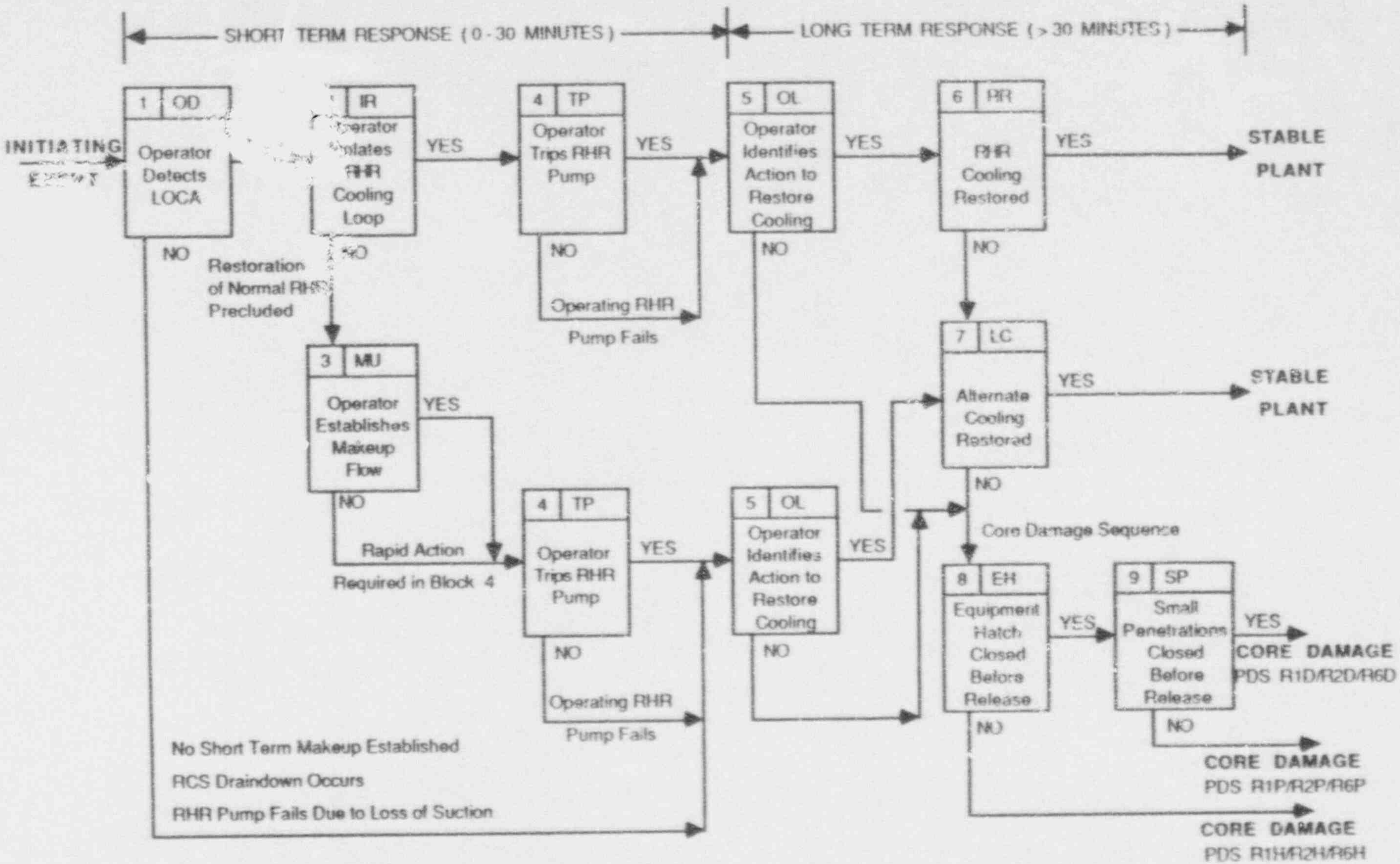
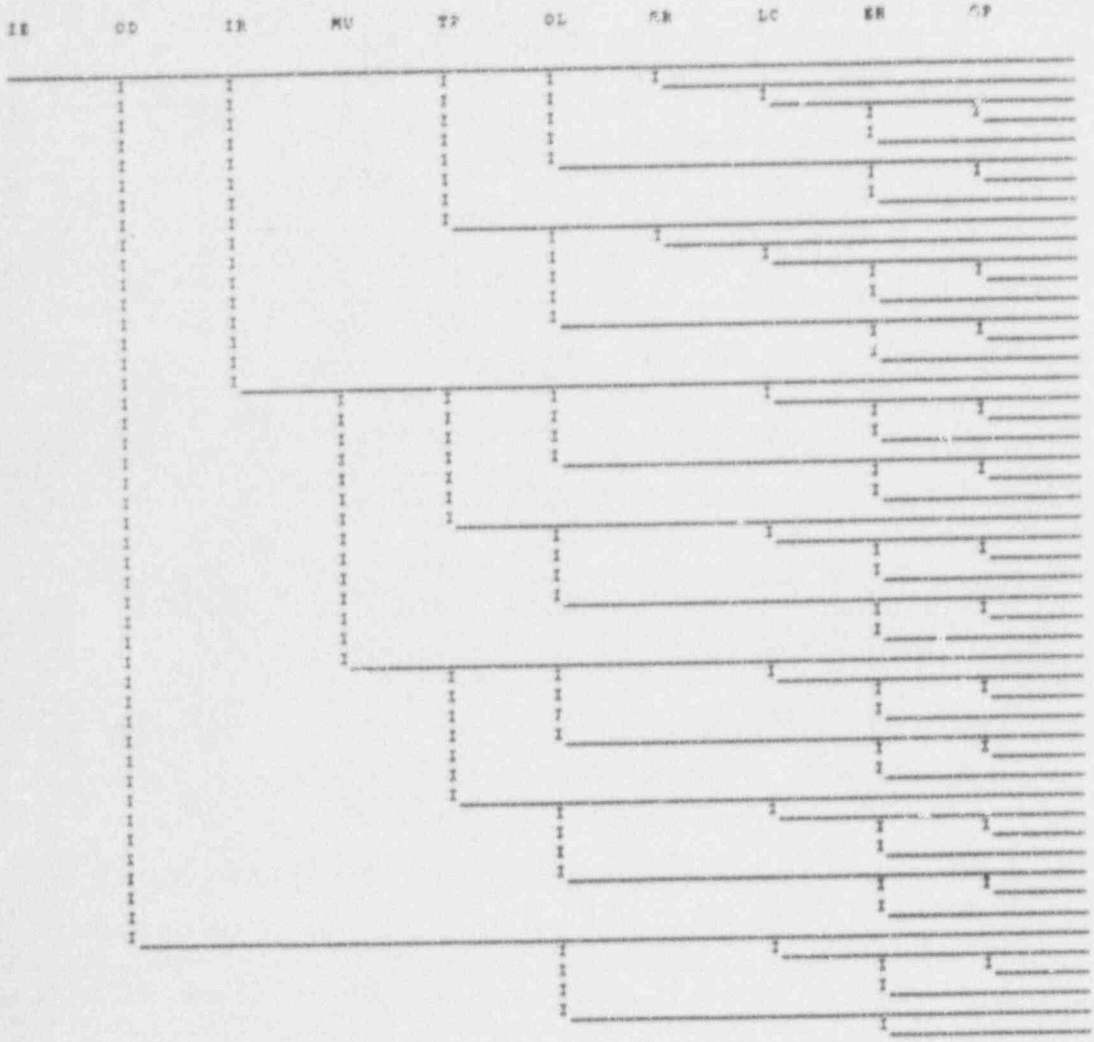


FIGURE 3-5 Event Sequence Diagram for Shutdown LOCAs

FIGURE 3-6 SHUTDOWN LOCA TREE

EVENT	NAME OF EVENT
IE	INITIATING EVENT
OD	Operator Detects LOCA
IR	Isolate RHR
MU	Makeup Flow Initiated
TP	RHR pumps tripped
OL	Operator ID's LT Cooling Options
RR	Normal RHR restored
LC	Alternate LT Cooling
EH	Containment large openings secure
SP	Containment small openings secure



SEQ	END STATE
1	S
2	S
3	R6D
4	R6P
5	R6H
6	R6D
7	R6P
8	R6H
9	S
10	S
11	R6D
12	R6P
13	R6H
14	R6D
15	R6P
16	R6H
17	S
18	R2D
19	R2P
20	R2H
21	R2D
22	R2P
23	R2H
24	S
25	R2D
26	R2P
27	R2H
28	R2D
29	R2P
30	R2H
31	S
32	R2D
33	R2P
34	R2H
35	R2D
36	R2P
37	R2H
38	S
39	R2D
40	R2P
41	R2H
42	R2D
43	R2P
44	R2H
45	S
46	R2D
47	R2P
48	R2H
49	R2P
50	R2H

TABLE 3-1

PLANT DAMAGE STATE DEFINITIONS

PDS DESIGNATOR	PDS DEFINITION	END STATE DESCRIPTION
R1D	RCS Pressure Low, Reactor Cavity Wet, Containment Isolated.	Refueling pool seal LOCA; Top Events SP and EH successful.
R1P	RCS Pressure Low, Reactor Cavity Wet, Containment Penetrations Open.	Refueling pool seal LOCA; Top Event SP failed.
R1H	RCS Pressure Low, Reactor Cavity Wet, Containment Hatch Open.	Refueling pool seal LOCA; Top Event EH failed.
R2D	RCS Pressure Low, Reactor Cavity Dry, Containment Isolated.	RCS Conditions X, Y or LOCA; Top Events SP and EH successful.
R2P	RCS Pressure Low, Reactor Cavity Dry, Containment Penetrations Open.	RCS Conditions X, Y or LOCA; Top Event SP failed.
R2H	RCS Pressure Low, Reactor Cavity Dry, Containment Hatch Open.	RCS Conditions X, Y or LOCA; Top Event EH failed.
R6D	RCS Pressure High, Reactor Cavity Dry, Containment Isolated.	RCS Condition W, Top Events SP and EH successful.
R6P	RCS Pressure High, Reactor Cavity Dry, Containment Penetrations Open.	RCS condition W; Top Event SP failed.
R6H	RCS Pressure High, Reactor Cavity Dry, Containment Hatch Open.	RCS Condition W; Top Event EH failed.

SUMMARY OF INITIATING EVENTS

INITIATING EVENT (a)	MEAN FREQUENCY (PER YEAR)	DESCRIPTION	REPORT SECTION
Support System Failures			
LOSP(X) LOSP(W)	3.0E-2 2.7E-2	Loss of offsite power.	7.2.3
LPCCA(X) LPCCA(W)	2.9E-3 2.9E-3	Loss of the operating PCC Train A.	7.3.3
LSWA(X) LSWA(W)	3.0E-4 3.1E-4	Loss of the operating Service Water Train A.	7.4.3
LPCC(X) LPCC(W)	3.5E-7 1.5E-5	Loss of both PCC trains.	7.3.4
LOSW(X) LOSW(W)	3.8E-8 1.7E-7	Loss of all Service Water.	7.4.4
Internal/External Hazards Events			
FLSW(X) FLSW(W)	3.0E-7 2.7E-7	External flood, loss of all Service Water.	8.1.3
TCTL(X) TCTL(W)	5.1E-5 4.6E-5	Truck crash into the SF_6 transmission lines, a non-recoverable loss of offsite power.	8.1.4
FSGA(X) FSGA(W)	2.5E-3 2.3E-3	Fire in Switchgear Room A.	8.2.1
FCRAC(X) FCRAC(W)	4.1E-8 3.7E-8	Fire in Control Room causing loss of all AC power.	8.2.1
FETG(X) FETG(W)	1.4E-5 1.3E-5	Fire in the electrical tunnel above the RHR vault, causing loss of both trains of RHR and loss of one train of PCC and Service Water.	8.2.1
FETB(X) FETB(W)	1.4E-5 1.3E-5	Fire in electrical tunnel train B, causing loss of suction to the operating RHR train (A) and loss of opposite train (B) of SW.	8.2.1
FTBLP(X) FTBLP(W)	3.2E-4 3.1E-4	Fire in Turbine Building causing non-recoverable loss of offsite power.	8.2.1
FPCC(X) FPCC(W)	1.2E-6 1.0E-6	Fire in PAB causing loss of PCC.	8.2.1

TABLE 3-2

SUMMARY OF INITIATING EVENTS

INITIATING EVENT (a)	MEAN FREQUENCY (PER YEAR)	DESCRIPTION	REPORT SECTION
Internal/External Hazards Events (Cont'd)			
FPAB(X) FPAB(W)	1.9E-5 1.7E-5	Fire in PAB causing loss of SW and loss of one train of PCC	8.2.1
FLRHR(X) FLRHR(W)	1.6E-6 1.4E-6	Flood in RHR vault causing loss of both trains of RHR.	8.2.2
FL1SG(X) FL1SG(W)	4.5E-6 3.9E-6	Flood in turbine hall and switchgear room A, causing a non-recoverable LOSP and failure of essential Bus E5.	8.2.2
SSBO(X) SSBO(W)	1.1E-6 2.3E-6	Seismic station blackout - loss of all AC power.	8.1.1
SLL( )	3.8E-7	Seismic large LOCA and loss of off-site power.	8.1.1
Procedure-Initiated LOCAs			
L1(W)	2.5E-3	LOCA through stuck-open RHR relief valve.	4 & 5
L3(W)	3.9E-6	LOCA through RH-V33 (cavity discharge valve back to RWST).	6.4.3
L5(Y)	1.4E-4	LOCA through refueling pool seal.	4 & 5
L6(Y)	1.7E-5	LOCA through cavity drain valve.	4 & 5
LP(W)	7.5E-6	LOCA through the RHR pump seal.	4 & 5
LS(W)	2.1E-5	LOCA through the sump isolation valves.	7.5.3
Procedure-Initiated Transients			
W1A(W)	9.2E-2	Overpressurization event, 2 relief valves available (A); both RHR trains available (1); RCS filled (W).	4 & 5
W3A(W)	2.7E-5	Overpressurization event, 2 relief valves available (A); operating RHR pump cavitating (3); RCS filled (W).	4 & 5

SUMMARY OF INITIATING EVENTS

INITIATING EVENT (s)	MEAN FREQUENCY (PER YEAR)	DESCRIPTION	REPORT SECTION
Procedure-Initiated Transients (Cont'd)			
W3B(W)	2.0E-5	Overpressurization event, 1 relief valve available (B); operating RHR pump cavitating (3); RCS filled (W).	4 & 5
W3C(W)	7.1E-6	Overpressurization event, no relief valves available (C); operating RHR pump cavitating (3); RCS filled (W).	4 & 5
W3N(W)	2.2E-2	Operating RHR pump cavitating (3); RCS filled (W).	4 & 5
X3N(X)	6.2E-2	Operating RHR pump cavitating (3); RCS drained (X).	4 & 5
Y3N(Y)	1.3E-3	Operating RHR pump cavitating (3); RCS at refueling level (Y).	4 & 5
X4N(X)	3.1E-3	Operating RHR pump cavitating, standby pump unavailable (4); RCS drained (X).	4 & 5
W5A(W)	4.6E-4	Overpressurization event, 2 relief valves available (A); operating RHR pump failed (5); RCS filled (W).	4 & 5
W5B(W)	1.2E-7	Overpressurization event, 1 relief valve available (B); operating RHR pump failed (5); RCS filled (W).	4 & 5
W5C(W)	4.8E-8	Overpressurization event, no relief valves available (C); operating RHR pump failed (5); RCS filled (W).	4 & 5
W5N(W)	5.4E-2	Operating RHR pump failed (5); RCS filled (W).	4 & 5
X5N(X)	6.2E-2	Operating RHR pump failed (5); RCS drained (X).	4 & 5
Y5N(Y)	5.2E-3	Operating RHR pump failed (5); RCS at refueling level (Y).	4 & 5

SUMMARY OF INITIATING EVENTS

INITIATING EVENT (a)	MEAN FREQUENCY (PER YEAR)	DESCRIPTION	REPORT SECTION
Procedure-Initiated Transients (Cont'd)			
W6A(W)	4.7E-3	Overpressurization event, 2 relief valves available (A); operating RHR pump failed, standby pump unavailable (6); RCS filled (W).	4 & 5
W6B(W)	9.3E-9	Overpressurization event, 1 relief valve available (B); operating RHR pump failed, standby pump unavailable (6); RCS filled (W).	4 & 5
W6C(W)	1.2E-9	Overpressurization event, no relief valves available (C); operating RHR pump failed, standby pump unavailable (6); RCS filled (W).	4 & 5
W6N(W)	2.0E-3	Operating RHR pump failed, standby pump unavailable (6); RCS filled (W).	4 & 5
X6N(X)	6.0E-4	Operating RHR pump failed, standby pump unavailable (6); RCS drained (X).	4 & 5

NOTES:

(a) The designator in parenthesis indicates the RCS condition at the time of the initiating event. RCS condition designators are defined as follows:

W - RCS filled and intact,
X - RCS drained and open,
Y - RCS at refueling level.

TABLE 3-3

PROCEDURE-INITIATED EVENTS - DESIGNATOR DEFINITIONS

RCS CONDITION			W RCS FAILED				X RCS DRAINED	Y REFUELING
RHR AVAILABILITY			OVERPRESSURE CONDITION					
			YES			NO	NO	NO
			2 RELIEF PATHS	1 RELIEF PATH	0 RELIEF PATHS	NO RELIEF REQUIRED	NO RELIEF REQUIRED	NO RELIEF REQUIRED
			A	B	C	N	N	N
Operating RHR Available	Standby Available	1	W1A	**	**	*	*	*
	Standby Unavailable	2	+	**	**	*	*	*
RHR Suction Lost	Standby Available	3	W3A	W3B	W3C	W3N	X3N	Y3N
	Standby Unavailable	4	+	+	+	+	X4N	+
Operating RHR Unavailable	Standby Available	5	W5A	W5B	W5C	W5N	X5N	Y5N
	Standby Unavailable	6	W6A	W6B	W6C	W6N	X6N	+

* 1N is the Normal (Stable) Endstate Condition where RHR cooling is available and no overpressure condition exists.

2N is also a Stable Endstate Condition where RHR cooling is available but standby pump is unavailable, and no overpressure condition exists.

** 1B and 1C are not possible because with both RHR pumps available at least the 2 RHR relief paths are available.

2C is not possible because at least the 1 RHR relief path is available with the operating RHR

2B is not possible because any single suction loss resulting in only one relief path is always assumed to occur in the operating RHR train precluding 2B.

\+ No procedure-initiated events were identified, which resulted in these conditions.

4.0 PROCEDURE INITIATED EVENTS MODEL

Procedure-initiated events represent the category of initiating events which occur due to operator errors or failures of equipment during execution of shutdown procedures. To identify such initiators, an event tree model is developed for each of the six major plant evolutions. In developing the event trees, operating experience and Seabrook-specific procedures and systems configurations were considered.

Operating experience events were reviewed to gain a perspective on how shutdown initiating events can occur due to procedural errors and/or equipment malfunctions. Appendix A summarizes loss of decay heat removal experience events from 1982 through 1986. These events supplement NSAC-52 (Reference 7) which includes events through 1981.

Seabrook-specific procedures used during shutdown were reviewed in detail including walkdowns in the plant. These procedures are described in Secti[illegible] An overview of the model is provided in Section 4.1, and the ev[illegible] are described in Section 4.3.

4.1 [illegible] of the Model

T[illegible] types of plant shutdowns are modeled:

Case A: Non-drained maintenance shutdown - outages for maintenance or inservice inspections (ISI) which do not require draining the RCS.

Case B: Drained maintenance - outages for maintenance or ISI that require draining the RCS (e.g., steam generator tube inspections).

Case C: Refueling shutdown - outages for refueling and subsequent maintenance.

These three categories envelope all types of plant shutdowns.

Event trees are used to model possible procedural errors and equipment failures, for each of the cases above. Figure 4-1 shows the major plant evolutions which are modeled in Cases A, B, and C. Event trees were developed to describe possible degraded conditions which could occur during execution of these procedures due to errors or equipment failures. The Procedural Event Trees (PETs) developed to model the major plant evolutions are:

Tree 1 - Cooldown to Cold Shutdown
Tree 2 - Drain Down RCS
Tree 3 - Fill Refueling Cavity
Tree 4 - Drain Refueling Cavity
Tree 5 - RCS Fill and Gas Evacuation
Tree 6 - Cold Startup to Hot Standby

The endstates of sequences in the event trees represent either a stable state that transfers to the next plant evolution (procedure event tree) or an initiating event that transfers to the plant response model (shutdown transient or LOCA trees).

As shown in Figure 4-1, Case A (maintenance outage with RCS loops full) models a non-drained shutdown and involves only two procedure events trees; cooldown to cold shutdown (Tree 1) and cold startup (Tree 6). Case B (maintenance outage - RCS loops drained to the vessel flange or the hot leg mid-plane) models a drained maintenance shutdown and involves four trees; cooldown (Tree 1), RCS drain down (Tree 2), RCS fill and evacuation (Tree 5), and cold startup (Tree 6). Case C (refueling outage) models a refueling shutdown and involves all six procedure event trees.

Since by definition every sequence can have a different endstate, it is necessary to group or bin these endstates into a practical number. Sequence endstates are defined according to the effect on the plant. The type of plant information that is tracked by end-state definition is availability of RHR, overpressure, RCS level, steam generator availability, and recovery time.

The annual frequency of entering the Procedure Event Trees is calculated separately for Cases A, B, and C based on the data in Section 9.2. This annual frequency for each type of shutdown (A, B, and C) is used as the initiating frequency of Tree 1 for the corresponding case. Stable sequences transfer to the subsequent procedure tree as the initiating event of the new procedure tree. The quantification process for Cases A, B, and C is discussed further in Section 5.5.

4.2 Summary of Seabrook Procedures

The shutdown Procedure Event Trees are based on Seabrook Station operating procedures for plant evolutions during shutdown. Seabrook Station operating procedures guide the plant staff through three typical shutdown types (Cases A, B, and C) as discussed in Section 4.1:

Non-drained maintenance outage (Case A),
Drained maintenance outage (Case B),
Refueling outage (Case C).

The six major plant evolutions that are accomplished in the course of these shutdowns have separate operation procedures, as follows:

	Name	Procedure No.
1.	Cooldown to cold shutdown	OS1000.04
2.	Draining down the RCS	OS1001.02
3.	Refueling cavity fill	OS1015.02
4.	Refueling cavity drain	OS1015.10
5.	RCS fill and evacuation	OS1001.01
6.	Cold startup to hot standby	OS1000.01

These six operating procedures reference additional procedures that are used to perform activities related to placing systems in standby or restoring systems to operable status after the shutdown activities are completed.

4.2.1 Reactor Cooldown To Cold Shutdown (OS1000.04)

The goal of this procedure is to place the RCS in a cold shutdown condition (i.e., in Mode 5, which requires that the average coolant temperature is less than 200°F).

The reactor is slowly cooled and depressurized from an average primary coolant temperature (T_{AVG}) of 557°F and primary pressure (P) of 2235 psig down to about 100°F and 50 psig. The cooldown rate is maintained at less than or equal to 50°F per hour. During the initial phase of the cooldown, heat is transferred to the ultimate heat sink via the steam generators.

The time after shutdown required to reach cold shutdown (i.e., T_{AVG} less than 200°F) can vary as a minimum between 7.2 hours when two RHR trains are used and 38 hours when one RHR train is used (Reference 11, Figures 5.4-5 and 5.4-6).

The Seabrook Technical Specifications require that one train of low pressure injection be available in Mode 4 (200° < T_{AVG} < 350°F). Only one RHR train is used for decay heat removal in this mode while the other remains operable and capable of taking suction from the RWST and the containment sump (i.e., operable to perform its ECCS function).

As pressure is decreased in the RCS, safety system actuation signals that are initiated on low reactor pressure, such as the SI signal, are disabled to reduce the chance of inadvertent repressurization by the charging and safety injection pumps.

Reactor coolant circulation is maintained using a main RCS pump to provide adequate mixing for heat removal and accurate temperature monitoring when the pressure is above 325 psig.

During the RCS cooldown the shutdown procedure requires that both Safety Injection pumps and one charging pump be rendered inoperable by having their control switches placed in the "pull to lock" position. Additionally, the electrical supply breakers for these pumps are racked out and the breakers secured in the racked out position.

The RHR system is placed in operation when RCS temperature is less than 350°F and RCS pressure is less than 365 psig. Opening of the RHR suction valve is precluded at pressure greater than 365 psig by a pressure interlock. Should RCS pressure exceed 660 psig, these suction valves receive an automatic close signal.

Operating procedures require that if RCS pressure decreases below 325 psig, the operating RCS pump(s) must be tripped to prevent pump damage as a result of low net positive suction head (NPSH).

The steam generators remain operable while the RHR system is placed in operation. When RCS temperature is less than 270°F, the steam generator can be placed in "wet layup" (i.e., the secondary side filled with water with a nitrogen blanket overpressure) or in "dry layup" (i.e., the secondary side water drained with a nitrogen fill) depending on the reason for the shutdown. If the shutdown is not for drained RCS maintenance and is of short duration, the steam generators are expected to remain operable.

RCS pressure is normally maintained at about 50 psig using a steam bubble in the pressurizer. However, if RCS draining is scheduled, the pressurizer bubble is collapsed and the pressurizer is brought solid prior to being drained.

Overpressure protection at RCS temperatures less than 329°F is provided by (1) the pressurizer PORV actuated by the Low Temperature Overpressure System (LTOP) or (2) the RHR suction relief valves in each train (setpoint = 450 psig), or (3) the pressurizer vent.

Low temperature overpressure protection is automatically placed in service when the cold leg temperature is below 329°F. The actuating pressure is a function of RCS temperature and is shown in Figure 3.4-4 of the Seabrook Technical Specifications (Reference 19). Upon receipt of an actuation signal, the PORVs will open to relieve pressure.

The RHR suction valves are placed in the cross-train alignment mode to minimize the chance of having both RHR relief valves isolated. The RHR suction valve "cross-train alignment" removes power from the open cross train valve in the suction line as shown in Figure 4-8. When Train A of the RHR system is operating in the RHR mode, both suction valves are opened with the suction valve powered from the B Train power source having its power removed. Both suction valves in RHR Train B are opened and the one that is normally powered from the Train A electrical power source has its motor statter racked out. The two remaining suction valves remain open. This scheme provides protection against a spurious auto isolation signal isolating both RHR suction lines which then isolates the RHR suction relief valves.

4.2.2 Draining The RCS (OS1001.02)

The RCS is degassed and drained down prior to refueling or drained maintenace using this procedure.

The RHR system is used to drain the RCS inventory to the Primary Drain Tank (PDT). The void created in the RCS during the drain down is filled with nitrogen gas (N_2).

Prior to implementing this procedure, the pressurizer bubble has been collapsed, the reactor coolant pumps (RCP) have been secured, and RCP number 1 seal leakoffs have been isolated. The RCS evacuation system is aligned to degas the RCS and provide a N_2 blanket. A temporary level monitor (Tygon tube) is installed and opened to the RCS.

As the RCS is drained down, the pressurizer level indicator LI-462 reading is compared to the indicated level in the temporary level transmitter. When level is about 5 to 10% pressurizer level, the RHR flowrate is reduced from the nominal 3000 GPM to 1000 GPM, to prevent pump cavitation.

Next, the head vent is opened when level is below the top of the reactor head. The reactor is degassed using the RCS evacuation pump. After degassing, the level is decreased to -7 feet (7 feet below the vessel flange) which is the elevation of the mid-plane of the vessel hot leg nozzle.

Reactor vessel level indicator LI-9405 is located in the RCS loop #1 crossover leg, and is placed in service by opening its isolation valves. The RCS is then vented to atmosphere.

If refueling is planned, the following procedures are implemented prior to vessel drain down.

- MS0504.01 - Reactor missile shield and CRDM shroud cooling removal and storage
- MS0504.02 - Rx head seismic support removal
- MS0504.03 - CRDM shroud cooling ductwork removal
- MS0504.04 - Rx head vent piping removal
- MS0504.30 - Rx head spool piece removal and blind flange installation
- MS0504.05 - Removal of neutron shield panels
- MS0504.06 - Removal of Rx head insulation
- MS0504.07 - Installation of cavity seal and leak test

After vessel has been drained, these additional procedures are performed:

IS1690815	-	Retraction of incore detectors
MS0504.08	-	Detensioning reactor head studs
MS0504.09	-	Removal of reactor head studs
MS0504.26	-	Installation of Rx head lifting alignment pins and stud hole plugs.

Next, the cavity is filled per Procedure OS1015.02 and the reactor head is stored per Procedure MS0504.10.

4.2.3 Cavity Fill (OS1015.02)

The reactor cavity is filled using either RHR Train A or B. Before filling starts, the cavity seal is installed and the cavity drain line valve is closed and a blank flange is installed.

An operator is stationed at the valve in the RWST to RHR suction line, CBS-V2 or V5 depending on which RHR train is operating. The valve is cracked open and suction is taken from the RWST. The fill process is controlled so that the vessel head is not wetted during the fill process.

When the desired level is reached, the RWST-RHR suction valve is closed.

4.2.4 Cavity Drain (OS1015.10)

When refueling is completed, the upper internals are installed and the control rod extension shafts are relatched.

The refueling cavity is drained via the RHR system to the RWST. Train B of the RHR system is normally used to pass flow through valve RHR-V33 to the RWST. Containment spray pump CBS-9B is made inoperable by placing its control switch in the "pull-to-lock" position and the CBS-9B suction path from RWST is isolated by closing CBS-V6. A flow path from the RHR "B" Train to the RWST is established by:

- o closing CBS-V24, RHR-V26
- o opening RHR-V33, CBS-V5, RHR-V21.

RHR B pump (RH-8B) is started and the cavity is drained down while the vessel closure head is lowered. The drain operation is halted as the vessel head and associated equipment are installed.

If drained down maintenance is planned, the level is dropped to the RCS hot leg nozzle mid-plane.

4.2.5 RCS Fill and Evacuation (OS1001.01)

The objective of the procedure is to degas the RCS, fill the RCS, and remove air pockets located in the steam generator "U" tubes.

The temporary level transmitter is installed and put in service (if not still in operation). Prior to drawing a vacuum during the degassing operation, certain RCS instrumentation is isolated. The LTOP pressure transmitters are isolated during this period and cold overpressure protection is provided by the RHR suction relief valves using the "cross train" alignment scheme.

After initial degassing is completed, the fill process is started. An operator is stationed at the tygon tube and when level reaches the head vent, the head vent valve is closed and level is increased to 40 to 45 feet (relative to the top of the vessel flange) in the pressurizer. An I&C technician restores valved-out instrumentation and verifies cold calibration of LI-462, the pressurizer level indicator. LTOP is restored and the temporary level transmitter is removed. When level reaches 50 feet in the pressurizer, an operator is stationed at the pressurizer vent "bulls eye". Pressure is controlled between 0 and 50 psig when the pressurizer is filled and vent is closed.

RCS pressure is raised to 3.5 psig and the RC pumps are started and stopped using Procedure OS1001.05, RC Pump Operation. This process sweeps air in the "U" tubes into the vessel head and pressurizer. The RCS is depressurized to 50 psig and the reactor head vent and pressurizer vent is opened. Safety injection is aligned for operation.

A bubble is formed in the pressurizer using OS1001.06 Pressurizer Bubble Formation.

4.2.6 Cold Startup (OS1000.01)

The objective of this procedure is to bring the RCS from Mode 5 to Mode 3 Hot Standby.

The steam generators (S/G) are filled and placed in operation using Procedure OS1027.01 (Fill S/G) if in dry layup or OS1027.03 (Lowering S/G Level) if in wet layup.

The RCS temperature is slowly increased by adding RC pump heat and bypassing flow around the RHR heat exchanger. Letdown is increased to maintain pressurizer level.

The Mode 4 checklist is completed prior to RCS temperature exceeding 200°F. Containment spray system is restored to operable status and containment set for Mode 4 entry.

RCS temperature is increased gradually as the circulating water system, condensate system, and feedwater system are placed in service.

At RCS temperature of less than or equal to 350°F and pressure less than or equal to 425 psig, the RHR systems are aligned for ECCS operation. The Mode 3 checklist is completed prior to reaching an RCS temperature of 350°F. Emergency feedwater system is aligned to auto initiation.

When temperature T_{AVG} is greater than 325°F, the charging pumps are restored to operable status. The SI accumulators are filled when pressure reaches 850 to 950 psig.

Pressure and temperature are increased until RCS pressure equals 2235 psig and T_{AVG} is greater than 551°F.

4.3 Procedure Event Tree Development

Each step in the procedures was analyzed with respect to operator errors or hardware failures that could lead to the following transient conditions:

Loss of coolant (LOCA)
Loss of the operating train of RHR
Overpressure condition
Overpressure following loss of RHR

Operator errors committed during execution of the procedure can be categorized as:

Failure to control a process variable.
Failure to perform an action correctly.
Failure to perform an action in the proper sequence.

This investigative analysis has both inductive and deductive aspects. The deductive process determines the causes of failure of systems that are needed during reactor shutdown. The inductive process evaluates single errors or groups of errors that can lead to abnormal conditions. Failure modes that lead to a transient or LOCA condition are identified. Failure modes that do not affect RHR cooling or pressure relieving systems are usually discarded.

Operator actions usually depend on instrumentation and/or equipment to successfully complete the procedural step. If the hardware is not available, then the operator cannot complete the procedural step in many cases. For these situations, hardware required for the procedural evolution is identified. Failure expressions include contributions for both human error and hardware failures.

4.3.1 Procedure Event Tree Endstate Definitions

This section describes the definition and assignment of sequence "endstates" in the Procedure Event Trees. Each sequence in a Procedure Event Tree terminates in either a "stable" or "non-stable" plant state. Stable states represent instances in which normal shutdown evolutions will continue and the analysis of potential procedural errors is continued on a subsequent Procedure Event Tree. Non-stable states represent instances in which a failure (human or hardware) has occurred and corrective action must be taken to recover core cooling.

Non-stable plant states are modeled as plant response model initiators. Typical non-stable plant states include loss of RHR cooling, LOCA, and overpressure condition. Endstates are assigned to each Procedure Event Tree sequence by a pre-defined convention which accounts for:

The type of non-stable state resulting from the sequence (e.g., loss of cooling, overpressure, etc.)

The status of the RCS when the sequence occurred (e.g., RCS level, vessel head on or off, steam generator availability, etc.)

This information is tracked for each Procedure Event Tree sequence to permit an accurate evaluation of the plant/operator response. The following two sections describe the convention used to define and assign sequence endstates which contain the necessary plant status information.

4.3.1.1 Transient Type Designator

A two-character designator is used to identify the type of sequence in a Procedure Event Tree. The possible transient types are:

loss of cooling
loss of cooling with overpressure
overpressure
LOCA

For non-LOCA transient initiators the first character identifies whether a loss of cooling has occurred by representing the availability of the two RHR cooling trains. The following convention is used:

RHR Suction Lost	Operating RHR Train Available	Standby RHR Train Available	First Character In Transient Type Designator (Non-LOCA)
No	Yes	Yes	1
No	Yes	No	2
Yes	*	Yes	3
Yes	*	No	4
No	No	Yes	5
No	No	No	6

* The operating train with suction lost is assumed to fail unless it is tripped. This is questioned in top event TP in the transient tree.

By this convention it can be seen that, for example, a first character of "5" represents a loss of cooling event with the standby RHR pump available.

For non-LOCA transient initiators, the second character specifies whether an overpressure event has occurred, and if so, how many RCS pressure relief paths are available to help mitigate the condition. The following convention is used:

Overpressure Condition Exists	RCS Pressure Relief Paths Available	Second Character In Transient Type Designator (Non-LOCA)
Yes	2 or more	A
Yes	1	B
Yes	0	C
No	(not necessary)	N

Using the above two characters, the following types of non-LOCA transient initiators are possible outcomes of Procedure Event Tree sequences:

RHR AVAILABILITY		OVERPRESSURE CONDITION			
		YES			NO
		2 RELIEF PATHS	1 RELIEF PATH	0 RELIEF PATHS	NO RELIEF REQUIRED
Operating RHR Available	Standby Available	1A	1B **	1C **	1N (Stable) *
	Standby Unavailable	2A +	2B **	2C **	2N (Stable) *
RHR Suction Lost	Standby Available	3A	3B	3C	3N
	Standby Unavailable	4A +	4B +	4C +	4N +
Operating RHR Unavailable	Standby Available	5A	5B	5C	5N
	Standby Unavailable	6A	6B	6C	6N

* 1N is the Normal (Stable) Endstate Condition where RHR cooling is available and no overpressure condition exists.

2N is also a Stable Endstate Condition where RHR cooling is available but standby pump is unavailable, and no overpressure condition exists.

** 1B and 1C are not possible because with both RHR pumps available at least the 2 RHR relief paths are available.

2C is not possible because at least the 1 RHR relief path is available with the operating RHR.

2B is not possible because any single suction loss resulting in only one relief path is always assumed to occur in the operating RHR train precluding 2B.

\+ No procedure-initiated events were identified which resulted in 2A, 4A, 4B, 4C, or 4N.

For Procedure Event Tree sequences which result in a LOCA condition, the sequence endstate is identified by the letter "L" followed by a number which designates the LOCA. The possible LOCAs considered in the Procedure Event Trees are:

L3 - LOCA occurs through valve RH-V-33 (operator fails to close valve) - Tree 4

L5 - LOCA occurs through the refueling cavity seal - Tree 3

L6 - LOCA occurs through valve SF-V-81 (operator fails to close valve) - Tree 3

4.3.1.2 RCS Status Designator

The "transient types" represented by the designators described above can occur at various times during a plant shutdown. Since the response of the operator and plant systems to any transient will be affected by existing conditions in the plant, (e.g., RCS level, time after shutdown, reactor vessel head on or off, etc.) these conditions must be identified and included on the complete "endstate" assigned to sequences in the Procedure Event trees. This information is then used when assessing the operator and plant response to the transient in the Shutdown Transient Event Tree.

To determine what RCS "status" information to include in the sequence endstate definition, the Shutdown Transient Event Tree was reviewed. The following top events were identified as most dependent on RCS conditions.

Top Event OR - Operator Identifies Recovery Action

Success or failure of this event is sensitive to the RCS conditions at the time of the transient because the RCS conditions determine how much time the operator has available to identify an appropriate recovery action. RCS level and availability of steam generators are critical to ensuring significant time for the operators.

Top Event LC - Alternate Long Term Cooling

Success or failure of this event is a function of the RCS conditions at the time of initiation of the transient. Availability of steam generators to provide cooling depends on RCS Conditions (i.e., level, vents such as manways, etc.). Another potential path for successful cooling is gravity feed from the RWST into the RCS. RCS conditions which affect the ability to accomplish this cooling are adequate venting and low pressures (level, manways, etc.). Forced feed and bleed with pumps are dependent on Support Systems but not RCS Conditions.

Top Events EH - and SP Equipment Hatch/Containment Isolation

The time available to recover containment isolation is affected by RCS Condition. In the case of the equipment hatch, if it is off during draindown, it would be very difficult to replace it in the unlikely event of core damage.

The plant shutdown evolutions conducted during Case A, B, and C shutdowns were reviewed to assess the possible RCS conditions existing during each Procedure Event tree (Case A, trees 1 and 6; Case B, trees 1, 2, 5, and 6; Case C, trees 1 through 6). Table 4-1 summarizes the RCS conditions considered during each Procedure Event tree. Information in this table, and assumptions made, are discussed below.

Time After Shutdown

Time after shutdown affects the decay heat load and the time to uncover the core given loss of decay heat removal. The times shown are the minimum estimated time to enter the subject procedures in the given shutdown case based on data from Section 9.2.

Vessel Head and Steam Generator Manways

Reactor vessel head and steam generator manways can be on or off. If the head or steam generator manways are off, it is assumed that steam generator cooling is not a potential success path for long term cooling. The head is modeled to be off only during Procedure Event Tree C3, Fill Refueling Cavity.

Dams

If the steam generator nozzle dams are in, steam generator cooling would be unavailable to at least the applicable generators with dams installed. With dams installed, the vessel water level is more likely to be at the vessel flange allowing more time for operator actions.

Vents

The RCS is vented during procedures 2 through 5. A large vent exists if the reactor vessel head is off or the SG manways are open. For these cases, steam generator cooling is unavailable and gravity feed from the RWST is available. RWST gravity feed with small vents open (normal vents on vessel head and pressurizer) depends on the decay heat load and as shown in Appendix B these are not very effective.

SGs

The steam generators (at least 2 of 4) can be available or unavailable depending on the type of shutdown. The steam generators are unavailable if they are in dry layup, if manways are open on any one (1) of the four (4) steam generators, or if the reactor vessel head is off.

RCS Level

The RCS level depends on the procedure and the type of maintenance planned. The level can be at the hot leg midplane, reactor vessel head flange, RCS filled, or the refueling level.

Operator Time

The time available for operator action after loss of RHR before core uncovery depends on the time after shutdown (decay heat), steam generator availability and the RCS level. Supporting thermal hydraulic calculations are provided in Appendix B.

RWST

Gravity feed from the RWST is a potential success path for operators. If the RCS is filled, gravity feed is assumed not possible. If the RCS is drained, success depends on vent size as a function of time after shutdown (see Appendix B).

RCS Status Group

Based on the combination of RCS conditions, three RCS status groups are selected and assumed for the model as shown in Table 4-1. These groups are designated as follows:

Designator	Steam Generator Available (GC)	Operator Time (OR)	RWST Gravity Feed Available (FB)
W	Yes	$\geq$ 10 hours	No
X	No	2 to 3 hours	Yes
Y	No	$\geq$ 72 hours	No

Note that for Cases B2, B5, C2, C4, and C5 (case, tree) in Table 4-1, multiple RCS conditions may occur. For each of these cases a single set of RCS conditions was selected to represent the case, based on the following:

Case B2

It is assumed that for drained maintenance the SG manways will be removed during the maintenance period. It is also assumed that nozzle dams are not used, so that the RCS level is maintained at the hot leg midplane.

These assumptions are conservative with respect to steam generator availability (not available) but permit gravity feed of the RWST which may not be possible if manways are on and dams out. In any case, two steam generators should be available as a backup for heat removal when the primary system is closed or the ability to gravity feed RWST ensured (i.e., remove pressurizer safety valve).

Case B5

It is assumed, during the RCS fill and evacuation evolution, that 2 of 4 steam generators will be available. If the steam generators are not available, the time for operator action is shorter.

Case C2

It is assumed that during refueling shutdowns the steam generator manways will be on during the draindown evolution and not removed until refueling is completed. It is also assumed that steam generators will be available (secondary side filled) since it is considered unlikely that all 4 generators would be drained within three days after shutting down. Since Case C4 models most of the shutdown time and the drained case, these assumptions are reasonable.

Case C4

Similar to Case B2, it is assumed that steam generator manways will be removed during the maintenance period and that nozzle dams will not be used, requiring that the RCS level be maintained at the hot leg midplane. Steam generators are unavailable but gravity feed of the RWST is permitted as discussed above (modeled only for no support systems available).

Case C5

Similar to Case B5, it is assumed, during the RCS fill and evacuation evolution, that 2 of 4 steam generators will be available. If steam generators are not available, the time for operator action is reduced.

As discussed above and shown in Table 4-1, the following RCS Status Designators are assigned to Procedure Event Tree transients to track availability of steam generators, RWST gravity feed and time for operator recovery.

Procedure Event Tree	RCS Status Designator	RCS Condition
A1	W	RCS Filled, Intact
A6	W	RCS Filled, Intact
B1	W	RCS Filled, Intact
B2	X	RCS Drained, Open
B5	W	RCS Filled, Intact
B6	W	RCS Filled, Intact
C1	W	RCS Filled, Intact
C2	W	RCS Filled, Intact
C3	Y	RCS Filled to Refueling Level, Open
C4	X	RCS Drained, Open
C5	W	RCS Filled, Intact
C6	W	RCS Filled, Intact

4.3.1.3 Summary of Endstate Definitions

Combining the "Transient Type Designator" applicable to each Procedure Event Tree sequence with the "RCS Status Designator", appropriate for the Procedure Event Tree, provides a complete endstate definition of each Procedure Event Tree Sequence.

Table 4-2 summarizes which endstates can occur in each Procedure Event Tree. All endstates are not possible for all shutdown case and procedure event tree combinations. For example, the RCS is drained (X) only in case/tree B2 and C4. The RCS is at the refueling pool level (Y) only in tree 3 (C3). The overpressure conditions (A, B, C) can not occur when the RCS is drained and open (B2 and C4) or when the RCS is at the refueling pool level (C3).

4.3.2 Procedure Event Tree Structure

Sections 4.3.2.1 through 4.3.2.6 describe the structure of Procedure Event Trees 1 through 6. Each description consists of a brief description of the event tree top events and a figure showing the event tree and endstates for each sequence. As described in Section 4.3.1, the endstates track the availability of RHR trains, whether or not an RCS overpressure condition exists, and availability of RCS overpressure relief paths. This information is the complete information required to identify the "Transient Type Designator" for each event tree sequence, using the convention discussed in Section 4.3.1.

4.3.2.1 Cooldown to Cold Shutdown (Tree 1)

Procedure OS1000.04 was used as the model for bringing the reactor plant from a temperature of 557°F and a pressure of 2235 psig down to a temperature less than 200°F and a pressure between 0 and 50 psig. The event tree model is shown in Figure 4-2 for this procedure and the tree top events are described below.

> Top Event RV: Operator Opens RHR Suction Valve at < 450 psig
>
> This event questions whether the operator waits to open the valve until pressure is below 450 psig. Although there is an interlock to prevent valve opening at pressures above 365 psig, failure of the interlock together with operator error (attempting to open the valve prematurely above 450 psig) results in failure of this event and an RCS overpressure transient.

Top Event CT: Operator Sets Up RHR Cross-Train Valve Alignment

This event questions whether the operator correctly removes power from the suction valves per the cross-train alignment procedure. This scheme prevents isolation of both RHR pumps following a spurious valve closure signal. If the operator fails to correctly complete this alignment, it is assumed that the suction valves have power. This results in isolation (unavailability) of both RHR pumps after a spurious valve closure signal (in top event SA).

Top Event RI: Operator Initiates RHR

This event questions whether the operator correctly aligns and starts one of two RHR pumps. It is assumed that if the first RHR pump fails to start, the operator attempts to start the second pump so that failure to complete this action results in a loss of RHR cooling transient with both RHR pumps unavailable. Failure of RI is assumed to guarantee failure of top events LT and RM. LTOP (LT) arming temperature will not be reached.

Top Event LT: LTOP Operable

This event questions whether the Low Temperature Overpressure Protection sensors and circuitry function correctly. Failure of this event is assumed to result in loss of automatic pressurizer PORV opening for low temperature overpressure relief.

Top Event RM: RHR Maintained

This event questions whether the operating RHR pump continues to operate for the mission time appropriate to the Case (A, B, or C) under consideration. Failure of this event results in a loss of cooling transient.

Top Event SA: RHR Suction Available

This event questions whether adequate suction is maintained for the operating RHR pump. Failure of this event is assumed to be caused only by spurious closure of the RHR suction valve for the operating RHR pump. If top event SA fails after failure of top event CT, it is assumed that RHR suction valves for the operating and standby RHR pumps close on a spurious signal.

Top Event NC: No Excess Charging

This event questions whether the operator properly balances charging and letdown flow during the cooldown process. Failure of this event is assumed to result in excess charging, and thus an overpressure transient.

Figure 4-2 shows Procedure Event Tree 1 with the assigned end-states. The RCS status designator (see Section 4.3.1) for initiating events in Tree 1 is "W". The detailed structure of the tree is discussed below.

Sequence 1 is a stable state (cross-train alignment completed correctly, LTOP operable, and no overpressure or loss of cooling condition) and would transfer to the appropriate event tree depending on the Shutdown Case (A, B, or C) being analyzed. In sequence 2 an overpressure condition exists due to overcharging. Both RHR relief paths, as well as the the pressurizer PORV, are available to mitigate the overpressure condition. In sequence 3 suction is lost (SA failure) to the operating RHR pump resulting in a degraded RHR transient. Loss of suction results in unavailability of the associated RHR pump suction path and relief valve path. The loss of suction is assumed to occur by spurious closure of the RHR suction valve.

In sequence 3 no overpressure condition exists (NC is successful), so the number of overpressure relief paths is not important. Sequence 4 consists of loss of RHR suction with an overpressure condition due to excess charging. Since loss of suction results in unavailability of one RHR relief valve, only one RHR relief valve, and the pressurizer PORV, are available to mitigate the overpressure condition.

Sequence 5 is a loss of RHR cooling transient (failure to maintain RHR cooling), and sequence 6 is a loss of RHR cooling transient with an overpressure condition due to excess charging. It is assumed that failure of top event RM (RHR cooling maintained) does not result in unavailability of the associated RHR overpressure relief valve since the relief valve will continue to function following failure of the RHR pump. Thus, in sequence 6 both RHR overpressure relief valves, and the pressurizer PORV, are available to mitigate the overpressure condition. For sequence 7 RHR cooling is lost and suction is lost to the RHR pump, resulting in a loss of cooling transient and loss of availability of the associated RHR overpressure relief valve. Sequence 8 contains loss of RHR cooling, loss of RHR suction, and an overpressure condition due to excess charging. Due to the loss of suction, one RHR relief valve is unavailable and only one RHR relief valve and the pressurizer PORV are available for overpressure mitigation.

Sequences 9 through 16 are identical to sequences 1 through 8 except that LTOP is not operable which affects two endstates (sequences 12 and 16). Loss of LTOP operability is assumed to result in loss of availability of the pressurizer PORV for RCS overpressure mitigation. Note that sequence 9 is a stable plant state since a loss of LTOP operability alone does not result in a transient condition. This sequence would transfer to the next procedure event tree, depending on the shutdown case (A, B, or C). The undetected failure of LTOP is included in the quantification of top event LT in trees 5 and 6.

In sequence 17 the operator fails to initiate RHR cooling (top event RI fails), resulting in a loss of RHR cooling transient. Failure of top event RI is assumed to result in unavailability of both

RHR pumps since event RI does not fail unless the operator has tried unsuccessfully to start both RHR pumps. Failure of RI does not effect availability of the RHR overpressure relief valves since the valves will continue to function if the RHR pumps fail to start. LTOP is assumed to "fail" for the sequences with RI failed because the LTOP arming temperature setpoint will not have been reached. Thus, the PORV will not open before a high pressure challenge to RHR piping and RHR pump seal. This assumption applies to sequences 17 through 20 and 37 through 40. Sequence 18 consists of a failure to initiate RHR cooling and an overpressure condition due to excess charging. For this sequence only, the two RHR relief valves are available to mitigate the overpressure condition. In sequence 19 the operator fails to initiate RHR cooling (RI fails) and RHR suction is lost (SA fails, due to closure of an RHR pump suction valve). The loss of RHR suction causes loss of availability of the associated RHR relief valve. Sequence 20 contains failure to initiate RHR cooling, loss of RHR suction, and an overpressure condition due to excess charging. In this sequence, one RHR overpressure relief valve is unavailable due to loss of RHR suction (SA failure) and the pressurizer PORV is unavailable due to assumed failure of LTOP when RI fails. Thus, only one overpressure relief path is available to mitigate the overpressure condition.

Sequences 21 through 40 are identical to sequences 1 through 20 except that the operator has failed to correctly establish the RHR suction valve cross-train alignment (top event CT fails) which affects the end-states. The importance of the failure of top event CT is that if event SA subsequently fails (spurious closure of the suction valve to the operating RHR pump) it is assumed that the same spurious signal closes the suction valve to the standby RHR pump, thus isolating both RHR overpressure relief valves. The plant conditions identified for sequences 21 through 40 are therefore identical to those identified for sequences 1 through 20 except that for sequences in which top event SA fails, no RHR relief valves are available. Note that sequences 21 and 29 are stable plant states since failures of top event CT (sequence 21), or CT and LT (sequence 29) do not result in a transient condition. These undetected failures are included in the quantification of top events in subsequent procedural event trees.

In sequence 41 the operator opens RHR suction valves when the RCS pressure is above 450 psig (top event RV fails), resulting in pressurization of the RHR piping to the relief valve setpoint. In this sequence it is assumed that one RHR relief valve is available since the overpressure condition will be present when the first suction line is opened. It is also assumed that the PORV is unavailable to open at low pressure because the LTOP arming temperature setpoint will not have been reached.

4.3.2.2 Draining The Reactor Coolant System (Tree 2)

Procedure OS1001.02 was used to model the sequences of operator actions used to drain the RCS down to a point where the RCS water level is at the mid-plane of the hot leg nozzle. When this level is reached, drained maintenance can commence such as working on the steam generators or reactor coolant pump seals.

The event tree that models the draindown is shown in Figure 4-3 and the top events are described next.

Top Event TV: Operator Installs Temporary Level Transmitter

This event questions whether the operator correctly installs the tygon tube used to obtain RCS level measurements. If this event fails it is assumed that the operator will allow the RCS level to draindown too far (due to erroneous level indications) resulting in loss of suction for the operating RHR pump.

Top Event DR: Operator Reduces RHR Flow

This event questions whether the operator correctly reduces RHR flow from 3000 GPM to 1000 GPM. If the operator fails to accomplish this step in the procedure it is assumed that vortexing occurs in the RHR suction line, resulting in loss of suction to the operating RHR pump.

Top Event LM: Operator Initially Maintains Drained Level

This event questions whether the operator successfully balances RCS charging and letdown flow to maintain a stable level in the RCS. Failure of this event is assumed to result in loss of suction to the operating RHR pump due to vortexing.

Top Event VA: Operator Vents RCS to Atmosphere

This event questions whether the operator vents the RCS to atmosphere to ensure that accurate indications of RCS level are obtained using RCS level transmitter LI-9405. Failure to vent the RCS causes the level transmitter to indicate a level approximately seven feet above the actual level and is assumed to result in loss of suction to the operating RHR pump.

Top Event IO: Vessel Level LI-9405 Operable

This event questions whether the RCS level transmitter LI-9405 remains operable during execution of the RCS draindown procedure. Failure of this event is assumed to result in loss of suction to the operating RHR pump.

Top Event SA: RHR Suction Available

This event questions whether RHR suction is available for the operating RHR pump. Suction could be lost by spurious suction valve closure or by vortexing (a continuation of top event LM). Failure of this event results in loss of suction and is also conservatively modeled to cause isolation of the RHR relief valve. It is assumed that this event fails following failure of any previous top event which results in loss of suction to the operating RHR pump (i.e., top events TV, DR, LM, VA, and IO).

Top Event RM: RHR Maintained

This event questions whether the operating RHR pump continues to operate for the mission time appropriate to the Case (B or C) under consideration. Failure of this event results in a loss of cooling transient.

Figure 4-3 shows Procedure Event Tree 2. Note that over-pressure conditions are not modeled in this tree because of the drain down condition and the most likely transient cause is a reduction in level.

Procedure Event Tree 2 is used in the modeling of Case B and C shutdowns. In Case B (drained maintenance) the majority of the shut-down time is spent in this tree since this is where maintenance is modeled to occur. For Case C (refueling) only a small amount of time is spent in this tree since the refueling occurs in tree 3 and it is assumed that drained maintenance will take place in tree 4 after refueling. Due to the different plant conditions assumed to exist during RCS draindown for Cases B and C, the RCS status designator (see Section 4.3.1) is "X" for Case B and "W" for Case C.

Sequence 1 represents successful execution of the RCS draindown procedure and terminates in a stable plant state with both RHR pumps available. In sequence 2 top event RM (RHR maintained) fails resulting in loss of the operating RHR pump and a loss of cooling transient. In sequence 3 suction loss to the operating RHR pump (failure of top event SA) results in a loss of suction transient and loss of the associated RHR relief valve. Sequence 4 consists of a loss of suction and independent failure of the operating RHR pump (failure of top events SA and RM) resulting in a loss of cooling transient and loss of one RHR relief valve.

Sequences 5 through 14 all contain a guaranteed loss of suction to the operating RHR pump due to failure of a preceding top event (TV, DR, LM, VA, or IO).

In sequence 5 a loss of suction transient is assumed to result due to failure of level transmitter LI-9405 (top event IO fails). Sequence 6 contains failure of LI-9405 (top event IO) and failure of the operating RHR pump (top event RM) resulting in a loss of pump suction with independent failure of the pump.

In sequence 7 a loss of suction transient is assumed due to operator failure to properly vent RCS (top event VA fails) causing inaccurate operation of the RCS level transmitter and loss of RCS level. Sequence 8 contains failure to vent the RCS (top event VA) and failure of the operating RHR pump (top event RM) resulting in a loss of pump suction with independent failure of the pump.

In sequence 9 a loss of suction transient is assumed due to operator failure to maintain RCS level by matching charging and letdown flows (top event LM fails). Sequence 10 contains failure to maintain RCS level (top event LM) and failure of the operating RHR pump (top event RM) resulting in a loss of pump suction with independent failure of the pump.

In sequence 11 a loss of suction transient is assumed due to operator failure to reduce RHR flow (top event DR fails) causing vortexing of the operating RHR pump. Sequence 12 contains failure to reduce RHR flow (top event DR) and failure of the operating RHR pump (top event RM) resulting in a loss of pump suction with independent failure of the pump.

In sequence 13 a loss of suction transient is assumed due to operator failure to correctly install the tygon tube used for RCS level indication (top event TV fails) causing incorrect level indication to the operator. Sequence 14 contains of a failure to correctly install the tygon tube (top event TV) and failure of the operating RHR pump (top event RM) resulting in a loss of pump suction with independent failure of the pump.

4.3.2.3 Refueling Cavity Fill (Tree 3)

This event tree (Figure 4-4) models the Cavity Fill Procedure OS1015.02. Water from the RWST is pumped via the RHR system into the RCS and then through the vessel head opening into the refueling cavity. When water reaches the refueling level, the fill procedure is terminated. The event tree top events are discussed below:

Top Event DF: Operator Closes SF-V-81

This event questions whether the cavity drain valve SF-V-81 is properly closed prior to initiating cavity fill. Failure of this top event is assumed to result in a LOCA through this valve.

Top Event CS: Cavity Seal Intact

This event questions whether the cavity seal remains intact during the time the cavity is filled. Failure of this top event is assumed to result in a LOCA through the cavity seal.

Top Event SA: RHR Suction Available

This event questions whether the suction valve in the RHR cooling loop remains open during the cavity fill and refueling evolutions. Failure of this event (spurious closure of the valve) results in a loss of suction transient.

Top Event RM: RHR Cooling Maintained

This event questions whether the RHR train which is cooling the core continues to operate for the duration of the cavity fill and refueling evolutions. Failure of this event results in a loss of cooling transient.

The structure of Procedure Event Tree 3, shown in Figure 4-4, is discussed below. Note that no overpressure conditions can exist in this tree because the primary system is open (vessel head is off). Procedure Event Tree 3 is used only in modeling Case C (refueling) shutdowns. The RCS status designator assigned to tree 3 is "Y" (see Section 4.3.1).

Sequence 1 represents successful execution of the cavity fill and refueling procedures and terminates on a stable plant state with no loss of coolant and no loss of cooling. In sequence 2, top event RM (RHR cooling maintained) fails resulting in loss of the operating RHR pump pump and a loss of cooling transient. In sequence 3 the RHR suction valve for the operating RHR pump spuriously closes (top event SA fails) resulting in a loss of suction transient. Sequence 4 consists of spurious closure of the suction valve for the operating RHR pump with independent failure of RHR pump, resulting in a loss of cooling transient.

Sequence 5 is a LOCA due to failure of the cavity seal, and sequence 6 is a LOCA due to failure of the operator to close valve SF-V-81.

4.3.2.4 Draining The Refueling Cavity (Tree 4)

The refueling cavity is drained back to the RWST using the standby RHR system. Procedure OS1015.10 (Refueling Cavity Drain) was used to model the sequence of operator actions. Water level can be drained down to just below the top of the vessel flange or down to the mid-plane of the hot leg nozzle if drained maintenance is planned. The tree is provided in Figure 4-5 with top events described below.

Top Event CD: Operator Closes RH-V33

This event questions whether the operator successfully closes RH-V21 or RH-V33 (cavity drain valve to the RWST). Failure of this event results in a LOCA through RH-V33 (LOCA L3).

Top Event BR: Operator Aligns RHR-B for Cooling

This event questions whether the operator completes realignment of the RHR B-train from the cavity drain mode to a standby RHR cooling mode. The RHR B-train is used per procedure to pump water from the refueling cavity back to the RWST. Following this evolution the B-train must be realigned if it is to be available for RHR cooling. Failure of this event does not result in a transient but results in unavailability of the standby RHR pump.

Top Event DM: Drain for Maintenance

This event questions whether the RCS will be drained to the level of the hot leg nozzle (event "success") or maintained at the level of the head flange (event "failure") after refueling.

Top Event RF: Operator Reduces RHR Flow to 1000 GPM

This event questions whether the operator successfully reduces RHR flow to 1000 GPM (when lowering RCS level to the hot leg nozzle) in order to prevent vortexing in the operating RHR pump. Failure of this event results in loss of suction to the RHR pump and guaranteed failure of event SA.

Top Event LM: Operator Maintains Desired Level

This event questions whether the operator initially achieves the desired RCS level by balancing charging and letdown flows. For a drained condition (event DM "successful") the target level is 7 feet below the head flange. For a non-drained condition (event DM "failed") the target level is 4 inches below the head flange. Failure of this event results in vortexing in the operating RHR pump and guaranteed failure of event SA.

Top Event SA: RHR Suction Available

This event questions whether RHR suction is available for the operating RHR pump. This event also includes operator maintaining the desired level (continuation of event LM). Either spurious closure of RHR suction valve or vortexing can cause the loss of RHR suction. Failure of previous top events RF and LM guarantee failure of SA.

Top Event RM: RHR Cooling Maintained

This event questions whether the operating RHR pump continues to operate for the duration of the cavity drain and post-refueling maintenance evolutions. Failure of this event results in a loss of cooling transient.

The structure of Procedure Event Tree 4, shown in Figure 4-5, is discussed below. Note that overpressure conditions are not modeled in this tree because of the reduced level conditions assumed and the most likely error or failure is assumed to cause a reduction in level. Since no overpressure conditions are identified in tree 4 the number of relief paths available does not alter the endstate assignments. Procedure Event Tree 4 is used only in modeling Case C (refueling) shutdowns. The RCS Status Designator assigned to Tree 4 is "X" (see Section 4.3.1).

Sequence 1 represents successful execution of the cavity drain and post-refueling maintenance procedures and terminates in a stable plant state with both RHR pumps available. In Sequence 2 top event RM (RHR cooling maintained) fails resulting in loss of the operating RHR pump and a loss of cooling transient. In sequence 3 the operating RHR pump suction valve spuriously closes (failure of top event SA) resulting in a loss of suction transient. Sequence 4 consists of a loss of suction with independent failure of the operating RHR pump (failure of top events SA and RM) resulting in a loss of cooling transient.

In sequence 5 the operator fails to maintain the desired RCS level (top event LM fails). Failure of top event LM is assumed to cause the RCS level to drop sufficiently to cause vortexing and loss of suction to the operating RHR pump. Top event SA is not questioned in the tree if top event LM has previously failed since suction to the operating RHR pump is already lost.

Sequence 6 consists of a failure of top event LM, as in sequence 5, and the additional independent failure of the operating RHR pump which results in a loss of cooling transient.

Sequences 7 and 8 model failure of the operator to reduce RHR flow to 1000 GPM (top event RF fails) which is required to avoid RHR pump vortexing when drained to the hot leg nozzle. This event is not questioned if the level is maintained at the head flange (if top event DM "fails") because RHR flow does not need to be reduced at this level. Top event SA is not asked if top event RF has previously failed since suction to the operating RHR pump is already lost. Top event LM is not asked in sequences 7 and 8 since the failure of top event RF causes an interruption of the cavity drain procedure. In sequence 8, top event RM (RHR cooling maintained) fails resulting in a loss of cooling transient.

Sequences 9 through 14 are identical to sequences 1 through 8 except that sequences 1 through 8 model a drained maintenance condition (top event DM "successful", level decreased to the hot leg nozzle) and sequences 9 through 14 model a maintenance condition in which the level is maintained at the head flange (top event DM "fails"). As noted above, top event RF is not questioned if top event DM fails because reduction of RHR flowrate is not required if the level is maintained at the head flange.

Sequences 15 through 28 are identical to sequences 1 through 14 except that in sequences 15 and 28 the operator has failed to realign the B-train RHR for cooling (top event BR failed) resulting in the additional unavailability of the standby RHR pump in each sequence.

Sequence 29 is a loss of suction which results from failure of the operator to properly close the cavity drain valve RH-V33 (top event CD fails). Following failure of top event CD, no further top events are questioned in the tree because execution of the cavity drain procedure will be interrupted by the need to respond to the loss of suction.

4.3.2.5 Fill The RCS (Tree 5)

The RCS is filled using Procedure OS1001.01, Reactor Coolant System Evacuation Fill and Vent. This procedure is used to determine the specific operator actions and the sequence of action in filling and removing noncondensible gases from the RCS. These procedural actions are modeled in the event tree in Figure 4-6 and the top events are described below.

Top Event TL: Operator Verifies Temporary Level Transmitters

This event questions whether the operator correctly assesses operability of the tygon tube prior to initiating RCS fill. Since the temporary level transmitter is not continuously monitored for level indication during drained maintenance, but is used during RCS fill, its operability must be checked. Operability is verified by checking the level reading against that provided by level indicator LI-9405. If this event fails, it is assumed that inaccurate level indications will cause the operator to overfill the RCS causing an overpressure transient. Top events LM and LT are guaranteed to fail given TL failure.

Top Event CT: Operator Ensures X-Train Valve Alignment

This event questions whether the operator correctly ensures that power is removed from the RHR suction valves per the cross-train alignment procedure to prevent isolation of both RHR pumps following a spurious valve closure signal. If the cross-train depowering is misaligned and the operator fails to detect and correct it, it is assumed that the suction valves have power and will isolate both RHR pumps after a spurious valve closure signal. Closure of an RHR suction valve also results in loss of the associated RHR relief valve for overpressure relief. This event includes failure of CT due to misalignment in tree 1 or misalignment following test or maintenance of the suction valves. If this misalignment is not detected and corrected in tree 5, it is assumed that CT is failed.

Top Event LM: Operator Maintains Level at 45 Feet

This event questions whether the operator successfully stabilizes and maintains the RCS level at 45 feet above the reactor vessel flange (indicated by the tygon tube) by balancing charging and letdown flow. Level must be maintained while maintenance operations are conducted. Failure of this event is assumed to result in an overpressure transient due to overfilling on the RCS. Although failure to maintain level could also result in underfilling the RCS and loss of level, it is assumed that a failure of this nature would be corrected due to the time available for corrective operator action and the number of warning signals which would alert the operator to a low RCS level condition.

Top Event CC: Operator Cross-Calibrates LT-462

This event questions whether the operator correctly calibrates pressurizer level indicator LI-462 to the level indicated by the tygon tube. Failure of this event is assumed to result in an overpressure transient due to overfill of the RCS, caused by inaccurate pressurizer level indications from LI-462.

Top Event LT: LTOP Operable

This event questions whether the Low Temperature Overpressure Protection sensors and circuitry are correctly tested for operability and restored to service after being isolated prior to RCS fill. Failure of this top event is assumed to result in failure of the LTOP system. This event is not the same as top event LT asked in Procedure Event Tree 1. In Tree 1, top event LT asked only whether LTOP sensors and circuitry function correctly. Success or failure of top event LT on Tree 1 is assumed to have no impact on success or failure of top event LT on Tree 5 since the event in Tree 5 includes an operability test of the LTOP system which, if correctly performed, will restore a failure from Tree 1.

Top Event PU: Operator Maintains Level With Pressure = 325 psig

This event questions whether the operator successfully maintains RCS level during evolutions conducted to vent noncondensible gases from the RCS. These evolutions include increasing RCS pressure to 325 psig, "bumping" the reactor coolant pumps to "sweep" noncondensible gases to vessel head or pressurizer, and reducing RCS pressure to 50 psig to vent the gases. During these evolutions, the RCS is water solid and RCS level must be maintained by balancing charging and letdown flow. Failure of this event is assumed to result in an overpressure transient due to excess charging.

Top Event SA: RHR Suction Available

This event questions whether suction is maintained for the operating RHR pump. Failure of this event (e.g., spurious closure of the suction valves) results in loss of suction to the operating RHR pump, loss of the associated RHR relief valve, and a loss of suction transient.

Top Event RM: RHR Cooling Maintained

This top event questions whether the operating RHR pump continues to operate for the duration of the RCS fill evolution. Failure of this event results in a loss of cooling transient.

RCS status indicator "W" (see Section 4.3.1) applies to all endstates in Tree 5.

Sequence 1 models successful execution of the RCS fill procedure and terminates in a stable plant state with no loss of RHR cooling, and no overpressure condition. In sequence 2 the operating RHR pump fails (top event RM fails) resulting in a loss of cooling transient. In sequence 3 RHR suction is lost for the operating RHR pump (failure of top event SA) resulting in a loss of suction transient and loss of the associated RHR relief valve. Sequence 4 consists of a loss of suction with independent failure of the operating RHR pump (failure of top events SA and RM) resulting in a loss of cooling transient and loss of one RHR relief valve.

Sequences 5 through 8 are identical to sequences 1 through 4 except that in sequences 5 through 8 the operator has failed to properly maintain RCS level while RCS pressure = 325 psig (top event PU is failed) and an overpressure condition is assumed to result on each sequence.

Sequences 9 through 16 are identical to sequences 1 through 8 except that in sequences 9 through 16 the pressurizer PORV is unavailable because top event LT (LTOP operable) has failed.

In sequence 17 the operator fails to cross-calibrate LT-462 with the level indicated by the tygon tube (top event CC fails) which is assumed to result in an overpressure condition. In this sequence top events LT (LTOP operable) is assumed unavailable and top event PU (operator maintains level at pressure = 325 psig) is not asked since the overpressure condition interrupts execution of the RCS fill procedure. Sequences 18 through 20 are similar to sequences 2 through 4 except that in sequences 18 through 20 top event CC has failed, resulting in an overpressure condition.

Sequences 21 through 24 result in identical transient conditions as sequences 17 through 2 . In sequences 21 through 24 an overpressure condition is caused by failure of the operator to maintain RCS level at 45 feet (top event LM fails). Top events CC (operator cross-calibrates LT-462) and PU (operator maintains level at pressure = 325 psig) are not asked in sequences 21 through 24 because failure of top event LM and the resulting overpressure condition interrupts execution of the RCS fill procedure.

Sequences 25 through 48 are identical to sequences 1 through 24 except that in sequences 25 through 48 the operator has failed to set up the correct cross-train depowered suction valve lineup (top event CT failed). The failure of top event CT alone does not result in a transient. However, if top event SA (RHR suction available) fails subsequent to failure of top event CT, it is assumed that both RHR re´ ›f paths are isolated. The spurious signal which causes closure of the suction valve for the operating RHR pump is assumed to also cause closure of the suction valve for the standby pump.

Sequences 49 through 52 result in overpressure conditions due to failure of the operator to verify operability of the tygon tube level indicator (top event TL fails). Failure of TL is assumed to cause the operator to fail to maintain RCS level and overpressurize the RCS (i.e., results in guaranteed failure of top event LM). In these sequences top event LT (LTOP operable) is assumed unavailable and top events CC (operator cross-calibrates LT-462) and PU (operator maintains level at pressure = 325 psig) are not asked because failure of top event LM causes interruption of the RCS fill procedure. Sequences 49 through 52 are combinations of successes and failures of top events SA (RHR suction available) and RM (RHR maintained) in combination with failure of top event TL.

Sequences 53 through 56 are the same as sequences 49 through 52 except that in sequences 53 through 56 the operator has additionally failed to set up the depowered suction valve lineup (top event CT fails). Hence, in sequences 53 through 56 the failure of top event SA (RHR suction available) results in loss of both RHR relief valves.

4.3.2.6 Cold Startup (Tree 6)

Procedure OS1000.01 is used by the operators for startup. Figure 4-7 describes the types of sequences and steps modeled from this procedure with the top events described below.

Top Event LI: Operator Controls Inventory During Heatup

This top event questions whether the operator maintains inventory control while a bubble is drawn in the pressurizer and while the RCS inventory expands during heatup. Failure of this event is assumed to result in an overpressure condition due to the ongoing RCS heatup. Although failure of this event could also result in loss of RCS inventory it is assumed that a failure of this nature would be corrected by the operator due to the extended time available for corrective operator action and the number of warning signals which would alert the operator to a low RCS level condition.

Top Event LT: LTOP Operable

This top event questions whether both channels of Low Temperature Overpressure Protection function correctly. Failure of this event is assumed to result in loss of the pressurizer PORVs for RCS overpressure relief. If the LTOP system is not operable prior to entering Tree 6 (i.e., if top event LT failed in Trees 1 or 5 it is assumed not to be recoverable.

Top Event SA: RHR Suction Available

This top event questions whether suction is maintained for the operating RHR pump. Failure of this event (e.g., spurious closure of the suction valves) results in loss of suction to the operating RHR pump, loss of the associated RHR relief valve, and a loss of suction transient. If the suction valves have not been correctly depowered prior to entering Tree 6 (i.e., if top event CT is failed as an entry condition to Tree 6), it is assumed that failure of top event SA results in loss of suction and loss of RHR overpressure relief valves in both the operating and standby RHR trains.

Top Event RM: RHR Maintained

This top event questions whether the operating RHR pump continues to operate for the portion of the cold startup procedure which requires use of RHR cooling. Failure of this event results in a loss of cooling transient.

Top Event CT: Cross-Train Valve Alignment Correct

This event questions whether the cross-train RHR suction valve alignment is correct. This event tracks failures of CT in Tree 1 or in Tree 5. It is assumed that if CT is failed coming into Tree 6, it is not recoverable.

Top Event IS: Operator Isolates RHR

This top event questions whether the operator isolates the RHR system prior to RCS pressure increasing to greater than 450 psig. Failure of this event is assumed to result in an overpressure transient since the RHR relief valves are set to lift at 450 psig.

Figure 4-7 shows Procedure Event Tree 6 and provides a listing of the endstates for four different versions.

Sequence 1 models successful execution of the Cold Startup Procedure and terminates in Mode 3 operation. In sequence 2, the operator fails to isolate the RHR system prior to RCS pressure increasing above 450 psig (top event IS fails) resulting in a overpressure transient. In sequence 3 the operating RHR pump fails resulting in a loss of cooling transient. In sequence 4, RHR suction is lost for the operating pump (failure of top event SA) resulting in a loss of suction. Sequence 5 consists of loss of suction and independent failure of the operating RHR pump (failure of top events SA and RM) resulting in a loss of cooling transient.

Sequences 6 through 10 are identical to sequences 1 through 5 except that LT is failed. However, availability of LTOP is inconsequential because overpressure occurs only in sequence 7, for which both RHR valves are available.

Sequence 11 represents a failure of the operator to control RCS inventory during the heatup evolution (top event LI fails) which is assumed to result in an overpressure transient. In sequence 12 the operating RHR pump fails (top event RM fails) in addition to the operator failing to control RCS inventory during heatup (top event LI fails). This results in a loss of cooling transient concurrent with an overpressure condition.

Sequences 13 through 16 are overpressure transients (LI failed) with a loss of suction (SA failed). If event CT fails (sequences 14 and 16) the number of relief paths is reduced by one, from one RHR relief and one PORV to just one PORV available for pressure relief. Sequences 15 and 16 also have a hardware loss of RHR in addition to overpressure and loss of suction.

Sequences 17 through 22 are identical to sequences 11 through 16 except that top event LT is failed. This results in loss of the PORVs for low temperature overpressure protection function and, thus, the available pressure relief valves is reduced by one.

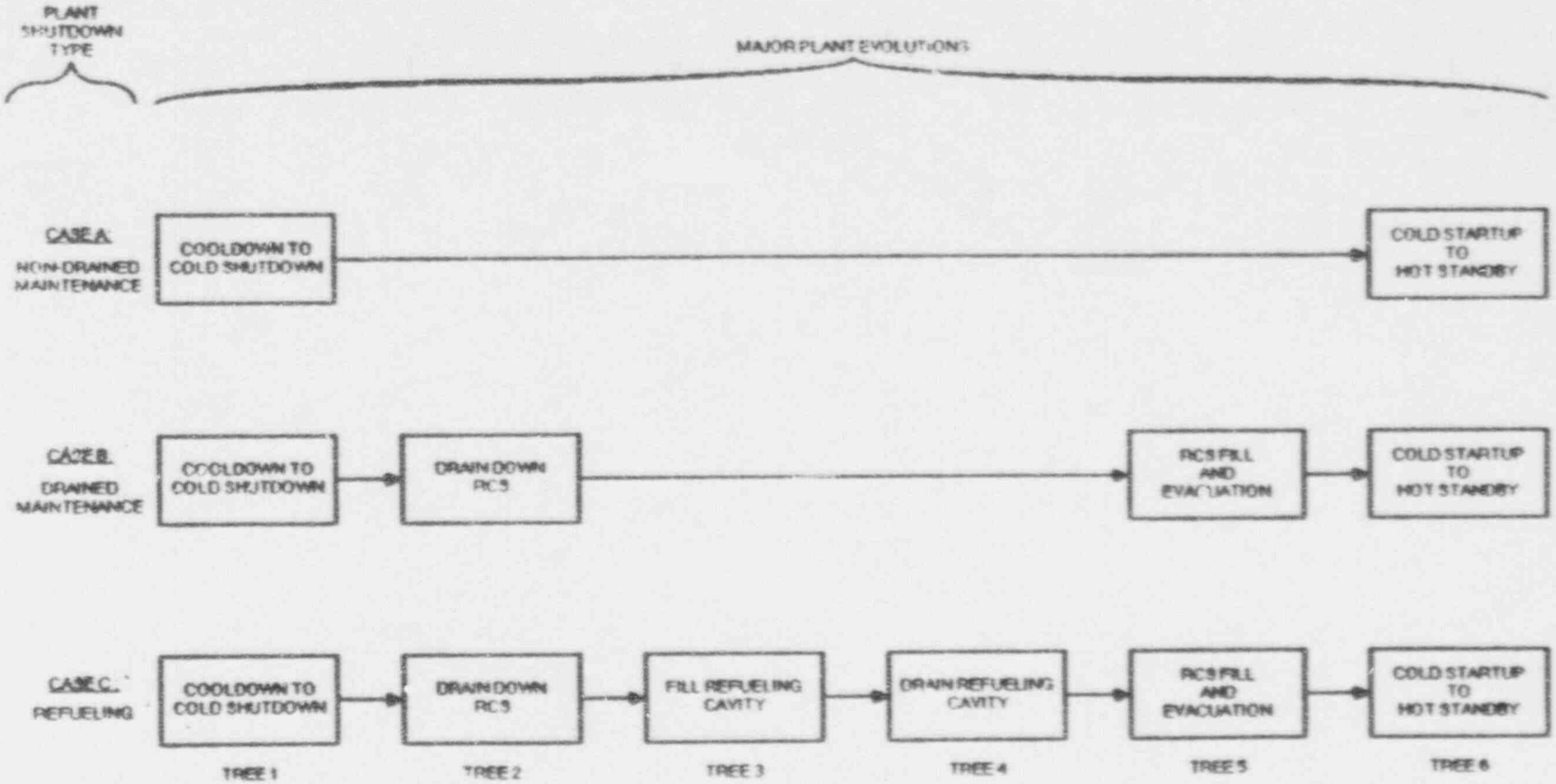
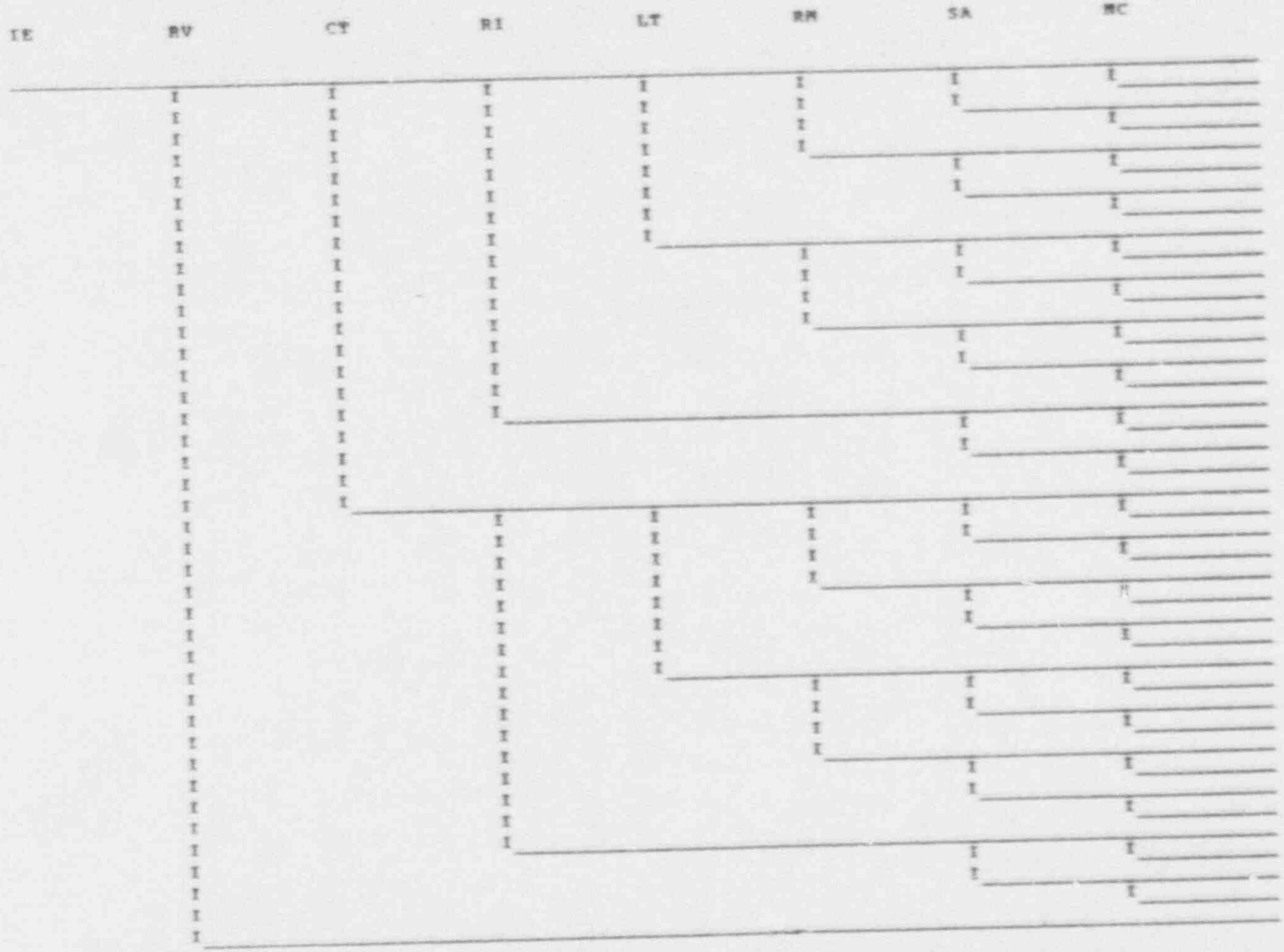


FIGURE 4-1 MAJOR EVOLUTIONS DURING PLANT SHUTDOWNS

FIGURE 4-2

Procedure Event Tree 1 - COOLDOWN

EVENT	NAME OF EVENT
IE	INITIATING EVENT
RV	RCS Press. < 365 psig
CT	Correct Cross-Train Alignment
RI	RHR Initiated
LT	LTOP Operable
RM	RHR Maintained
SA	RHR Suction Available
NC	No Excess Charging



SEQ	END STATE
1	S
2	W1A
3	W3M
4	W3A
5	W5M
6	W5A
7	W5M
8	W5A
9	S
10	W1A
11	W3M
12	W3B
13	W5M
14	W5A
15	W5M
16	W5B
17	W6M
18	W6A
19	W6M
20	W6B
21	S
22	W1A
23	W3M
24	W3B
25	W5M
26	W5A
27	W5M
28	W5B
29	S
30	W1A
31	W3M
32	W3C
33	W5M
34	W5A
35	W5M
36	W5C
37	W6M
38	W6A
39	W6M
40	W6C
41	W6A

FIGURE 4-3

Procedure Event Tree 2 - RCS DRAINDOWN

EVENT	NAME OF EVENT
IE	INITIATING EVENT
TV	Tygon tube installed
DR	Reduce RHR flow
LM	L=C
VA	RCS vented to atmosphere
IO	LI-9405 operable
SA	RHR suction available
RM	RHR maintained

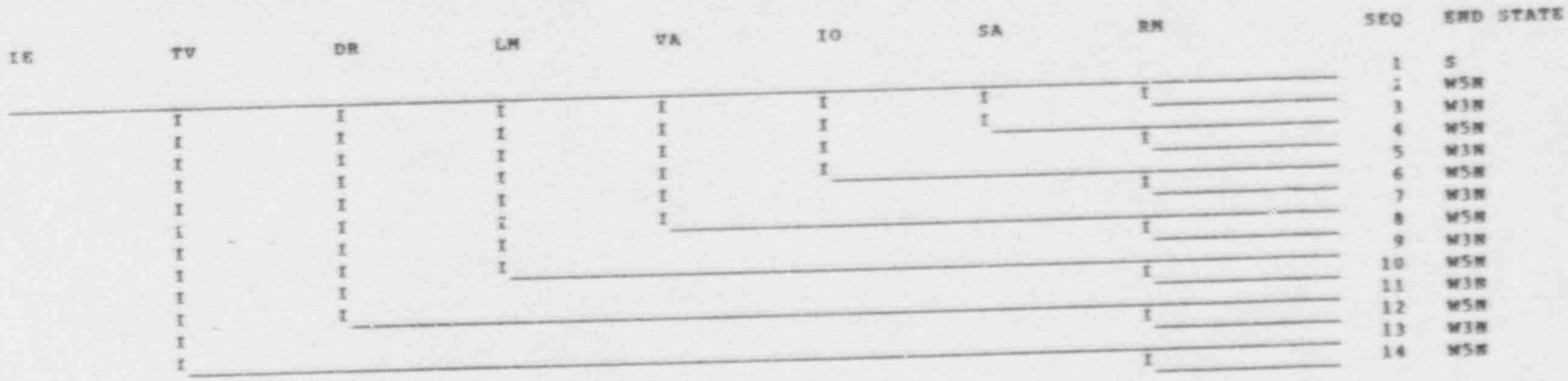


FIGURE 4-4

Procedure Event Tree 3 - REFUELING CAVITY FILL

EVENT	NAME OF EVENT
IE	INITIATING EVENT
DF	SF-V-81 Blocked
CS	Cavity Seal OK
SA	RHR suction available
RM	RHR maintained

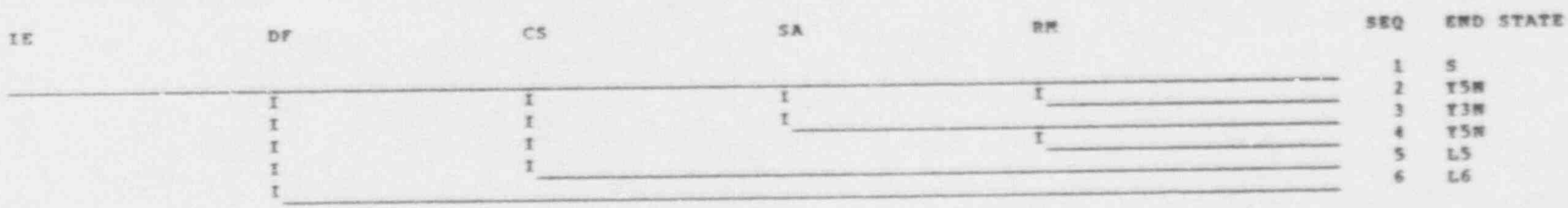
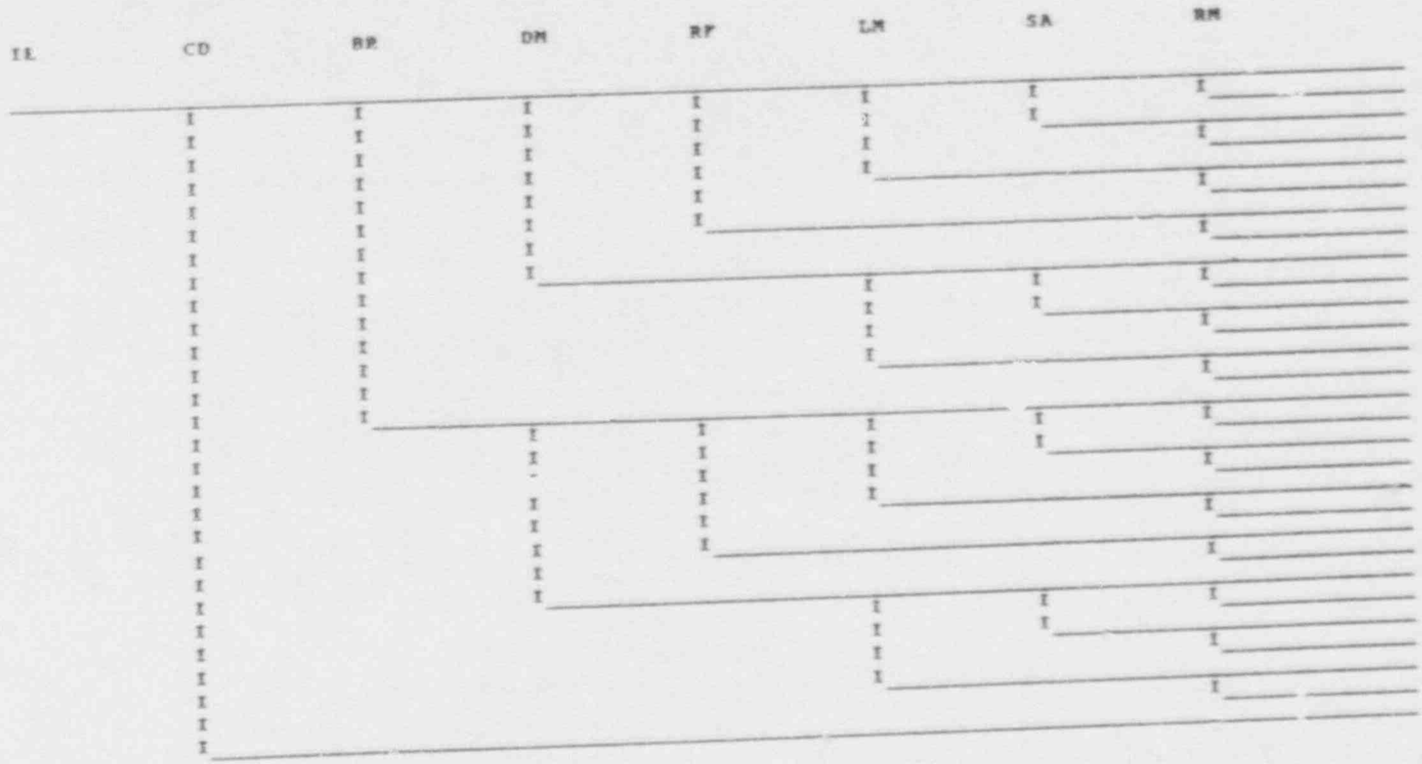


FIGURE 4-5

Procedure Event Tree 4 - REFUELING DRAIN

EVENT	NAME OF EVENT
IE	INITIATING EVENT
CD	RH-V33 closed
BR	RHR-B aligned for cooling
DM	Drain for maintenance
RF	Reduce RHR to 1000 gpm
LM	L=C
SA	RHR suction available
RM	RHR maintained



SEQ	END STATE
1	S
2	X5M
3	X3M
4	X5M
5	X3M
6	X5M
7	X3M
8	X5M
9	S
10	X5M
11	X3M
12	X5M
13	X3M
14	X5M
15	S
16	[illegible]
17	[illegible]
18	X6M
19	X4M
20	X6M
21	X4M
22	X6M
23	S
24	X6M
25	X4M
26	X6M
27	X4M
28	X6M
29	X4M

FIGURE 4-6

Procedure Event Tree 5 - RCS FILL

EVENT	NAME OF EVENT
IE	INITIATING EVENT
TL	Level operable
CT	Cross train alignment
LM	C=L Pzr. level
CC	LI-462 operable
LT	LTOP operable
PU	C=L, RCS pressure
SA	RHR suction available
RM	RHR maintained

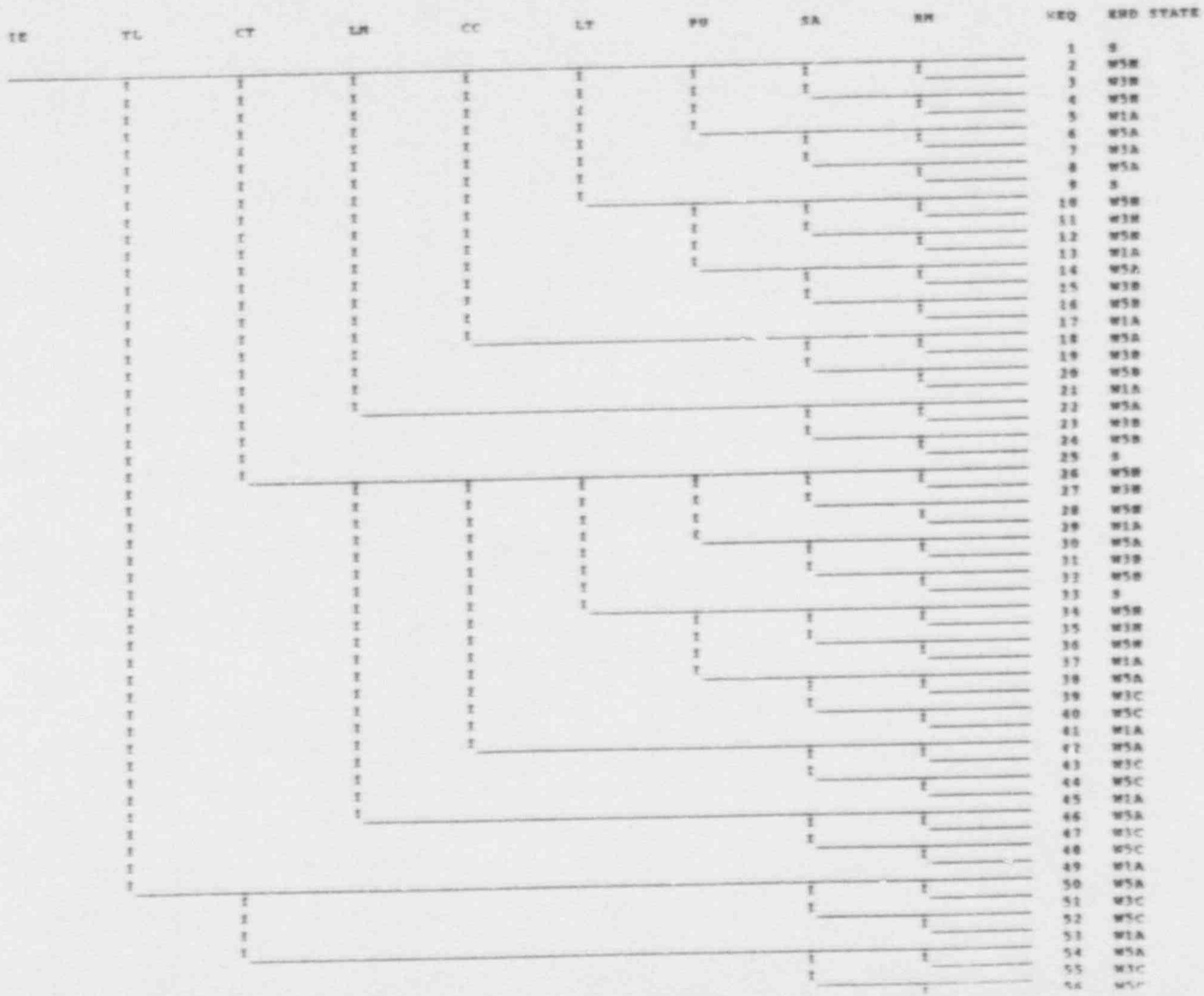
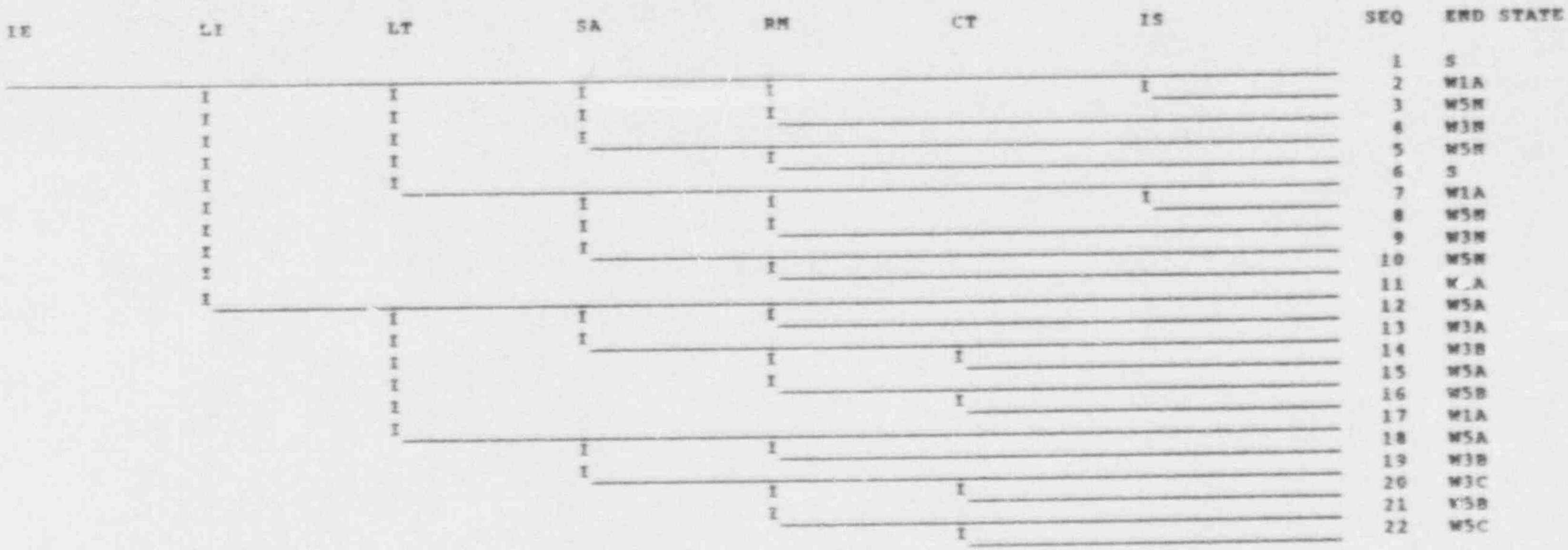


FIGURE 4-7

Procedure Event Tree 6 - COLD STARTUP

EVENT	NAME OF EVENT
IE	INITIATING EVENT
LI	Inventory controlled
LT	LTOP available
SA	RHR suction available
RM	RHR Maintained
CT	Event CT Failed in Tree A1
IS	RHR isolated



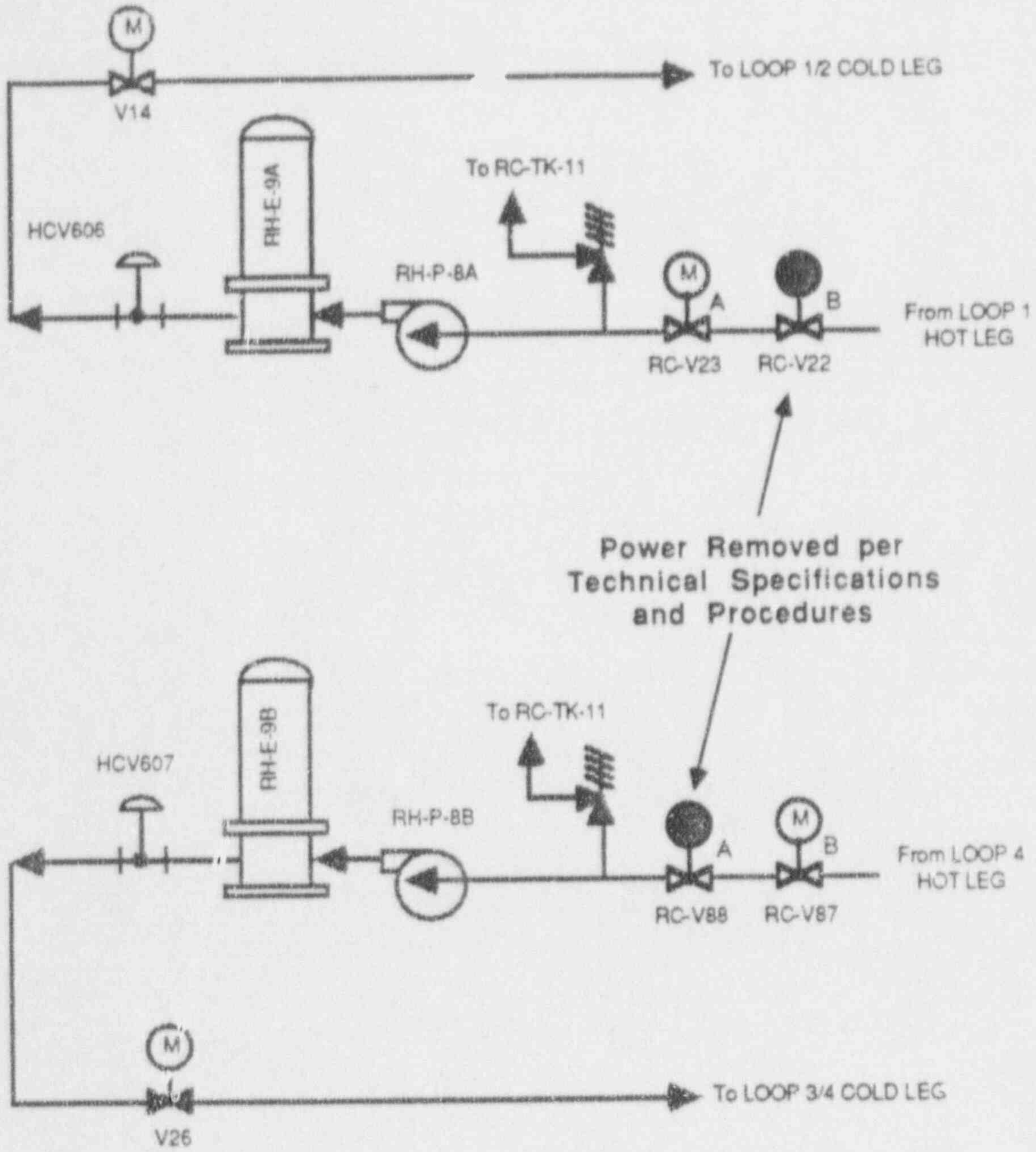


FIGURE 4 - 8
RHR CROSS-TRAIN ALIGNMENT

TABLE 4-1

RCS STATUS ASSUMPTIONS FOR SHUTDOWN CASE AND PROCEDURE

SHUTDOWN CASE & PROCEDURE	DAYS AFTER SHUTDOWN	VESSEL HEAD	SG MANWAYS	SG NOZZLE DAMS	RCS VENTS	SGs AVAILABLE	RCS LEVEL	MINIMUM OPERATOR TIME (HRS)	GRAVITY FILL AVAILABLE	RCS STATUS GROUP
A1	.5	On	On	Out	No	Yes	Filled	> 10 *	No	W
A6	2	On	On	Out	No	Yes	Filled	> 20 *	No	W
B1	.5	On	On	Out	No	Yes	Filled	> 10 *	No	W
B2	3	Off	Off	In	Large	No	Flange	3	Yes	–
		On	Off	Out	Large	No	HL	2	Yes	X
		On	On	Out	Small	Yes	HL	> 10	No	–
		On	On	Out	Small	No	HL	2	No	–
B5	20	On	On	Out	Small	Yes	Filled	> 20	No	W
		On	On	Out	Small	No	Filled	7	No	–
B6	21	On	On	Out	No	Yes	Filled	> 20	No	W
C1	.5	On	On	Out	No	Yes	Filled	> 10 *	No	W
C2	3	Off	Off	In	Large	No	Flange	3	Yes	–
		On	Off	Out	Large	No	HL		Yes	–
		On	On	Out	Small	Yes	Flange	> [illegible]	No	W
		On	On	Out	Small	No	Flange	3	No	–
C3	5	Off	Off	In	Large	No	RF	72	No	Y
		Off	On	Out	Large	No	RF	72	No	Y
C4	10	Off	Off	In	Large	No	Flange	5	Yes	–
		On	Off	Out	Large	No	HL	3	Yes	X
		On	On	Out	Small	Yes	HL	> 10	No	–
		On	On	Out	Small	No	HL	3	No	–
C5	60	On	On	Out	Small	Yes	Filled	> 20	No	W
		On	On	Out	Small	No	Filled	> 10	No	–
C6	65	On	On	Out	No	Yes	Filled	> 20	No	W

* assumes 4 SGs available.

TABLE 4-2

POSSIBLE ENDSTATES FOR EACH PROCEDURE EVENT TREE

PROCEDURE INITIATED EVENTS	SHUTDOWN CASE AND PROCEDURE											
	A1	A6	B1	B2	B5	B6	C1	C2	C3	C4	C5	C6
W1A	X	X	X		X	X	X				X	X
W3A	X	X	X		X	X	X				X	X
W3B	X	X	X		X	X	X				X	X
W3C	X	X	X		X	X	X				X	X
W3N	X	X	X		X	X	X	X			X	X
W5A	X	X	X		X	X	X				X	X
W5B	X	X	X		X	X	X				X	X
W5C	X	X	X		X	X	X				X	X
W5N	X	X	X		X	X	X	X			X	X
W6A	X		X				X					
W6B	X		X				X					
W6C	X		X				X					
W6N	X		X				X					
X3N				X						X		
X5N				X						X		
Y3N									X			
Y5N									X			
YL5									X			
YL6									X			
X4N										X		
X6N										X		
XL3										X		

5.0 MODEL QUANTIFICATION

This section describes the quantification of the plant model which involves quantifying and linking of the initiating events and event trees discussed in Sections 3 and 4. The results of the quantification are summarized in Section 2 in the form of core damage sequences and core damage contributions from initiating events. Section 5.1 provides an overview of the plant model quantification. Sections 5.2, 5.3, and 5.4 provide the details of the Support Tree, Transient Tree, and LOCA Tree quantification, respectively. Section 5.5 gives the details of the quantification of the procedural initiated events from the procedural event trees. The uncertainty analysis of the plant model is summarized in Section 5.6.

The split fraction quantification presented in this section along with the initiating event frequencies in Section 3 and the event tree structures in Sections 3 and 4 are the complete set of data needed to quantify the plant model. (Note that two events - seismic station blackout and seismic LOCA - are analyzed separately because of the nature of the uncertainty. The results of quantifying these sequences is contained in Section 8.1).

In this study the computer codes ETC9 (Reference 12) and MAXIMA6 (Reference 13) were used to quantify the model. ETC9 is used to quantify individual event t...s. MAXIMA6 generates complete sequences (linking) from initiating events through event trees to release states. The actual input and output files for ETC9 and MAXIMA6 are contained in calculation files.

5.1 Plant Model Overview

The plant model consists of i itiating events mapped through the support systems tree and then through either the Transient or LOCA trees. The end states of the transient and LOCA trees are plant damage states which are used in the calculation of offsite consequences. Sections 5.1.1 and 5.1.2 provide detailed information on how the plant model is quantified for each initiating eve :. Plant damage states are defined in Section 10.1.2 and are summarized in Table 3-1. Results showing initiating event contribution to each plant damage state is contained in Table 5-1.

The process of quantifying an event tree consists of assigning a split fraction to each branch in the tree. A split fraction is the frequency of "failure" of a given event tree top event and is generally dependent on the specific initiating event and on success or failure of previous top events. That is, a specific split fraction represents the frequency of failure of the top event given the conditions that precede it. These split fractions are linked together with the previous and subsequent events that correspond to the same conditions through the support tree and transient tree. The result is a set of core damage sequences that include all possible combinations of success and failure of the top events.

5.1.1 Transient Event Initiators

Table 5-2 describes the impact of initiating events on the support systems tree. Tables 5-3 and 5-4 show the specific split fractions used in the Support tree and transient tree for each initiating event. The basis for the quantifications and assignments of split fractions is given in Section 5.2 (Support tree) and Section 5.3

(Transient tree). The important dependencies that affect many top events are discussed below.

RCS Condition

During shutdown, the RCS can be in one of three general conditions:

Condition W - RCS filled and closed; secondary cooling available using steam generators.

Condition X - RCS drained to the level of the vessel flange or the hot leg mid-plane and RCS vented;

Condition Y - RCS open and filled to refueling level.

For each possible initiator, the plant is considered to be either in Condition W or Condition X. The internal/external hazards events are defined and quantified for Condition W and Condition X (e.g., LOSP(X), LOSP(W)). The procedural initiators are designated W or X depending on the status of the plant when the event occurs.

With the plant in Condition Y, there are no transients of importance because of the very long time available (several days) with loss of decay heat removal before core uncovery. Also, the time in this condition is relatively short (about one week) and the mitigation actions to refill the refueling pool are relatively simple.

The RCS condition affects the RHR system and its support systems. When the RCS is drained (Condition X), both trains are required to be operable. Thus, planned maintenance can occur only during Condition W. This affects top events GA, GB, WA, WB, PA, PB in the support tree and RR in the transient tree.

The RCS condition also affects the time for operator recovery which is modeled in OR for core recovery and EH and SP for containment isolation.

Offsite Power

On loss of offsite power, the diesel generators must start and run (top events GA, GB) and other normally operating systems must restart and continue to run (top events WA, WB, PA, PB, RR). Also, with loss of offsite power, the polar crane cannot be used. Thus, if the hatch is off, it cannot be replaced. Offsite power can be lost due to random causes (LOSP) or due to hazards such as fires (FCRAC, FTBLP), floods (FLSW, FL1SG), and truck crashes into the transmission lines (TCTL) which make offsite power unrecoverable. It is assumed that, if offsite power is available at the beginning of the transient, then electric power is assumed to be available throughout the event.

Single Support Systems

Loss of single support systems is modeled as an initiating event if it causes loss of the operating RHR train. For convenience, the operating train was assumed to the "A" train. Thus, events causing loss of the Support Train A requires the non-operating RHR train to be started and then run (top event RR). Initiating events causing loss of train A include random support system failures (LPCCA, LSWA), fires (FSGA), and floods (FL1SG).

Loss of Both Support Systems

Loss of both support systems guarantees failure of RHR cooling (top event RR). Long term cooling (top event LC) includes secondary cooling (boiling in the steam generators, eventual turbine driven EFW pump) for RCS Condition W and gravity feed from the RWST for RCS Condition X.

Overpressurization

Ov rpressure transients come only from the procedural event trees. No internal or external hazard events were identified which cause overpressurization. Transient tree top events PC, VO, and OC are affected by overpressure. Top event VO is dependent on the number of relief paths available, which is tracked in the procedure tree end state designator.

RHR Status

The status of RHR for the internal/external hazard initiators is a function of the support systems available except for three events, FETB, FETC, and FLRHR. These hazard events cause direct loss of RHR, not failure of support systems. From the procedural event trees, the status of RHR is tracked in the end state designators. Status includes availability or unavailability of the operating and standby trains. It also includes the operation of pump cavitating due to suction valve closure or low level. Transient tree top events SA and TP model operator response to the cavitating pump. Thus, top event RR is dependent on the initiating event, the support systems availability, and the status of the cavitating pump.

5.1.2 LOCA Event Initiators

Table 5-5 lists the split fractions used for each LOCA initiator in the LOCA tree. As shown in Table 5-3b, in the support tree, LOCA initiators are modeled as procedural initiators with RCS Condition W or Y. This is because LOCAs are s' ificant events only when the RCS is full. Also, the LOCA events identified do not directly affect the support systems.

The bases for the quantification and assignment of split fractions is given in Section 5.4 for the LOCA tree. The important dependencies are discussed below.

Isolation

If the LOCA is isolated, the event becomes a transient with long times available for recovery due to secondary cooling available. The LOCA tree models LOCA isolation by the operator closing the RHR suction valves. Thus, if isolation is successful, the operator must also trip the operating RHR pump to prevent damage. If the LOCA is not isolated, normal RHR cooling cannot be re-established and long term cooling requires feed-and-bleed or low pressure injection. For LOCA L5 and L6, isolation is not necessary because the inventory does not drain below the vessel flange. For LOCA LS, isolation is assumed to be guaranteed failed because of the size of the opening (large LOCA) and the short time for operator response.

Support Systems

The status of support systems affects the "hardware" top events in the LOCA tree - MU (charging pumps), RR (RHR pumps), and LC (charging and RHR pumps). Isolation (closing the RHR isolation valves - MOVs) is not affected by support systems because electric power is assumed available (i.e., LOCA and LOSP were not considered coincidents). Top event OL is dependent on support system status because operator response to the event depends on the options available. Long term cooling option with no support systems available is possible only if the LOCA is isolated.

LOCA Size

The size of the LOCA affects the time available to respond in the short term to diagnose (top event OD) and respond to the event (top events IR, MU, and TP). Also, if the LOCA is not isolated in the short term, the size affects the time to respond in the long term (OL). LOCAs LS (to the sump), L3 (RH-V33), and L5 (refueling pool seal) are all large LOCAs. LOCAs L1 (RHR relief valve) and L6 (refueling pool drain valve) are small LOCAs. LOCA LP (RHR pump seal) could range from a very small leak to a small LOCA.

Containment

LOCAs L3 to the RWST and LP to the RHR vault result in breaches of the containment and guaranteed failure of top event SP. For the other LOCAs, containment isolation depends on the time to core uncovery which is a function of LOCA size and isolation.

5.2 Plant Model: Support Tree Top Event Quantification

The description and quantification of the split fractions used in the Support Systems Event Tree are included below. The split fractions are summarized in Table 5-6. Each split fraction is defined for one of two RCS Conditions:

X = RCS drained to the vessel flange or hot leg mid-plane and RCS vented.
W = RCS filled and closed with secondary cooling available via at least two steam generators.

The other possible RCS Condition, with the vessel head off and flooded up to the refueling level (Y), is important to risk only for a LOCA condition because of the long time available for heatup and boil off.

The RCS Condition is significant to support systems because the Technical Specifications require two trains of RHR (and supports) when the RCS is drained (X). Thus, planned maintenance outages are modeled to occur only when the RCS is full (W).

5.2.1 Top Event GA

SUCCESS: Diesel Generator A and its support systems start on demand (LOSP) and run for 24 hours.

FAILURE: Diesel Generator A or its support systems fail to start or fail to run for the mission time.

HUMAN FACTOR: None, diesel auto starts on LOSP.

HARDWARE: See Section 7-2.

DEPENDENCIES:

GA1 = $\overline{GA}|$LOSP and RCS Condition W: LOSP(W), TCTL(W), FTBLP(W)

GA2 = $\overline{GA}|$LOSP and RCS Condition X: LOSP(X), TCTL(X), FTBLP(X)

GAF = Guaranteed failure of Diesel A: FCRAC, FLISG, FLSW

For all other internal/external initiators and for all procedure initiated events, it is assumed that offsite power is available and diesel generators are not necessary.

FAILURE SPLIT FRACTIONS: (mean values)

GA1 = 1.4E-1

GA2 = 1.1E-1

GAF = 1.0

5.2.2 Top Event GB

SUCCESS: Same as top event GA.

FAILURE: Same as top event GA. In addition, Diesel Generator B can be unavailable due to planned maintenance.

HUMAN FACTOR: None.

HARDWARE: Same as top event GA.

DEPENDENCIES: Same as top event GA except for initiator FL1SG which fails only GA. GB also depends on success or failure of GA.

GB1 = $\overline{GB}$|FL1SG(W)

GBA = $\overline{GB}$|GA and LOSP: LOSP(W), TCTL(W), FTBLP(W)

GBB = $\overline{GB}$|$\overline{GA}$ and LOSP: LOSP(W), TCTL(W), FTBLP(W)

GB2 = $\overline{GB}$|FL1SG(X)

GBC = $\overline{GB}$|GA and LOSP: LOSP(X), TCTL(X), FTBLP(X)

GBD = $\overline{GB}$|$\overline{GA}$ and LOSP: LOSP(X), TCTL(X), FTBLP(X)

GBF = Guaranteed failure of Diesel B: FCRAC, FLSW

FAILURE SPLIT FRACTIONS: (mean values)

GB1 = 3.1E-1

GBA = 3.0E-1

GBB = 3.3E-1

GB2 = 1.1E-1

GBC = 1.0E-1

GBD = 1.4E-1

GBF = 1.0

5.2.3 Top Event WA

SUCCESS:	Service Water Train A continues to operate for 24 hours.
FAILURE:	Service Water train fails to operate for 24 hours.
HUMAN FACTOR:	None.
HARDWARE:	See Section 7.4.

DEPENDENCIES:

WA1 = $\overline{WA}$|Procedure Initiated Event, RCS filled (W,Y) or LPCCA(W), LPCC(W), FETB(W), FPCC(W), FLRHR(W)

WA2 = $\overline{WA}$|Procedure Initiated Event, RCS drained (X) or LPCCA(X), LPCC(X), FETB(X), FPCC(X), FLRHR(X).

WA3 = $\overline{WA}$|LOSP(W), TCTL(W), FTBLP(W), FL1SG(W)

WA4 = $\overline{WA}$|same as WA3 except RCS Condition X

WAF = $\overline{WA}$|LSWA, LOSW, FLSW, FSGA, FPAB, FETG, FCRAC

FAILURE SPLIT FRACTIONS: (mean values)

WA1 = 2.7E-4

WA2 = 2.5E-4

WA3 = 2.2E-2

WA4 = 2.0E-2

WAF = 1.0

5.2.4 Top Event WB

SUCCESS: Same as top event WA.

FAILURE: Same as top event WA. Also, WB can be unavailable due to planned maintenance when the RCS is filled (Condition W,Y).

HUMAN FACTOR: None.

HARDWARE: See Section 7.4.

DEPENDENCIES: Same as top event WA except for initiators LSWA and FET3 which fail only Train A. Also WB depends on WA success or failure.

WB1 = $\overline{WB}$|RCS Filled (W,Y) or LSWA(W), FSGA(W), FETG(W)

WBA = $\overline{WB}$|WA and RCS Filled (W,Y) or LPCCA(W), LPCC(W), FPCC(W), FLRHR(W)

WBB = $\overline{WB}$|$\overline{WA}$ and RCS Filled (W,Y) or LPCCA(W), LPCC(W), FPCC(W), FLRHR(W)

WB2 = $\overline{WB}$|same as WB1 except RCS Condition X

WBC = $\overline{WB}$|same as WBA except RCS Condition X

WBD = $\overline{WB}$|same as WBB except RCS Condition X

WB3 = $\overline{WB}$|LOSP(W), TCTL(W), FTBLP(W), FL1SG(W)

WBE = $\overline{WB}$|WA and LOSP(W), TCTL(W), FTBLP(W), FL1SG(W)

WBG = $\overline{WB}$|$\overline{WA}$ and LOSP(W), TCTL(W), FTBLP(W), FL1SG(W)

WB4 = $\overline{WB}$|same as WB3 with RCS Condition W

WBH = $\overline{WB}$|WBE with RCS Condition X

WBI = $\overline{WB}$|WBG with RCS Condition X

WBF = $\overline{WB}$|LOSW, FLSW, FETB, FPAB, FCRAC

FAILURE SPLIT FRACTIONS: (mean values)	WB1	=	6.7E-2
	WBA	=	6.7E-2
	WBB	=	1.0E-2
	WB2	=	2.5E-4
	WBC	=	2.5E-4
	WBD	=	2.4E-4
	WB3		8.2E-2
	WBE	=	8.1E-2
	WBG	=	1.5E-1
	WB4	=	2.0E-2
	WBH	=	1.9E-2
	WBI	=	5.5E-2
	WBF	=	1.0

5.2.5 Top Event PA

SUCCESS: Primary component cooling water Train A continues to operate for 24 hours.

FAILURE: PCC Train A fails to operate for 24 hours.

HUMAN FACTOR: None.

HARDWARE: See Section 7.3.

DEPENDENCIES:

PA1 = $\overline{PA}$|Procedure Initiated Event, RCS filled (W,Y) or FETB(W), FLRHR(W)

PA2 = $\overline{PA}$|Procedure Initiated Event, RCS drained (X) or FETB(X), FLRHR(X)

PA3 = $\overline{PA}$|LOSP(W), TCTL(W), FTBLP(W)

PA4 = $\overline{PA}$|same as PA3 with RCS Condition X

PAF = $\overline{PA}$|LPCCA, LPCC, FETG, FPCC, LSWA, LOSW, FSGA, FCRAC, FLSW, FL1SG, FPAB

FAILURE SPLIT FRACTIONS: (mean values)

PA1 = 1.4E-3

PA2 = 1.3E-3

PA3 = 1.5E-3

PA4 = 1.3E-3

PAF = 1.0

5.2.6 Top Event PB

SUCCESS: Same as top event PA.

FAILURE: Same as top event PA. Also, PB can be unavailable due to planned maintenance when the RCS is filled (Condition W,Y).

HUMAN FACTOR: None.

HARDWARE: See Section 7.3.

DEPENDENCIES: Same as top event PA except for initiators LPCCA, FET3, and FPAB which fails only train A. Also, PB depends on PA success or failure.

PB1 = $\overline{PB}$|RCS filled (W,Y) or FSGA(W), FEIG(W), FLRHR(W), LPCCA(W), LSWA(W)

PBA = $\overline{PB}$|PA, RCS filled (W,Y) or FLRHR(W)

PBB = $\overline{PB}$|$\overline{PA}$, RCS filled (W,Y) or FLRHR(W)

PB2 = $\overline{PB}$|same as PB1 except RCS Condition X

PBC = $\overline{PB}$|same as PBA except RCS Condition X

PBD = $\overline{PB}$|same as PBG except RCS Condition X

PB3 = $\overline{PB}$|LOSP(W), TCTL(W), FTBLP(W), FL1SG(W)

PBE = $\overline{PB}$|PA and LOSP(W), TCTL(W), FTBLP(W)

PBG = $\overline{PB}$|$\overline{PA}$ and LOSP(W), TCTL(W), FTBLP(W)

PB4 = $\overline{PB}$|same as PB3 with RCS Condition X

PBH = $\overline{PB}$|same as PBE with RCS Condition X

PBI = $\overline{PB}$|same as PBG with RCS Condition X

PBF = $\overline{PB}$|LPCC, FPCC, LOSW, FCRAC, FLSW, FPAB, FETB

FAILURE SPLIT FRACTIONS: (mean values)	PB1	= 6.1E-2
	PBA	= 6.1E-2
	PBB	= 7.9E-2
	PB2	= 1.3E-3
	PBC	= 1.3E-3
	PBD	= 1.7E-3
	PB3X	= 6.1E-2
	PBE	= 6.1E-2
	PBG	= 8.7E-2
	PB4	= 1.3E-3
	PBH	= 1.3E-3
	PBI	= 1.0E-2
	PBF	= 1.0

5.3 Plant Model: Transient Tree Top Event Quantification

Table 5-7 contains a summary of the split fractions in the Transient Event Tree. The description and quantification of split fractions in this tree are included below.

5.3.1 TOP EVENT PC

SUCCESS: Primary system pressure is controlled (in Procedure Event Trees).

FAILURE: Pressure is not controlled causing an overpressurization transient and a relief valve lift demand condition.

HUMAN ERROR: None

HARDWARE: None

DEPENDENCIES: For the procedural initiated events, top event PC depends on transfer state information. The transfer state includes whether the sequence is an overpressurization event or not.

PCF = $\overline{PC}$|(Overpressure = A, B, or C) - Overpressure Transient

PCS = $\overline{PC}$|(Overpressure = N) - No Overpressurization

For internal/external initiators, no events have been identified which cause overpressurization.

PCS = $\overline{PC}$|internal/external initiators.

FAILURE SPLIT FRACTIONS: (mean values)

PCF = 1.0

PCS = 0.0

5.3.2 <u>TOP EVENT VO</u>

SUCCESS: At least one relief valve opens to reduce and control pressure, given an overpressure condition.

FAILURE: All available relief valves fail to open on demand.

HUMAN ERROR: None

HARDWARE: PORV or RHR relief valves fail to open on demand. See Section 7.5.2.

DEPENDENCIES: For the Procedural Event Tree initiated events, top event VO depends on transfer state information. As discussed in Section 4.3.1, the combinations of relief valves are binned into the following:

$VO1 = \overline{VO}|$(Relief Valves = 2 or more available) 2 RHR reliefs or 1 PORV and 1 RHR relief - A

$VO2 = \overline{VO}|$(Relief Valves = 1 available) - 1 PORV or 1 RHR relief - B

$VOF = \overline{VO}|$(Relief Valves = 0 available) - C

For internal/external initiators, since no overpressure events were identified (i.e., $\overline{PC}$ = PCF = 0.0), no relief valves are needed for overpressure protection. The Shutdown Transient Tree is constructed with no branch at VO if PC is successful.

FAILURE SPLIT FRACTIONS. (mean values)

VO1 = 3.03 E-6

VO2 = 4.27 E-3

VOF = 1.0

5.3.3 TOP EVENT OC

SUCCESS: Operator secures the overpressurization source and the relief valves (RHR relief valves or PORVs) reclose.

FAILURE: The operator fails to secure the source of the overpressurization or one or more relief valves fail to reclose.

HUMAN ERROR: Operator fails to isolate charging and/or to increase letdown after the relief valves lift (giving immediate alarms - level/temperature in the PRT) and before substantial liquid mass has escaped from the primary system.

$OP1_{OC}$ = 9.5E-4 (Section 6.2).

HARDWARE: Failure to close after opening for RHR relief valve or PORV. It is assumed that only one relief valve opens in response to overpressurization and thus, only one has to reclose. This was quantified using the PORV failure to reclose since it is conservative with respect to relief valve reclosing.

VC1 = 2.50E-2 (See Section 7.5.2).

DEPENDENCIES: Top event OC is asked only for overpressure events. As discussed in top event PC, no internal/external events were identified which resulted in overpressurization.

FAILURE SPLIT FRACTIONS: (mean values)

OC1 = $OP1_{OC}$ + VC1 = 2.6E-2

5.3.4 TOP EVENT SA

SUCCESS: uction flow to the operating RHR pump is maintained.

FAILURE: Suction flow to the operating RHR pump is lost due to suction valve closure or vortexing as a result of low primary coolant level.

HUMAN ERROR: None.

HARDWARE: None.

DEPENDENCIES: For the procedural initiated events, top event SA depends on transfer state information. If the top event SA in the Procedural Event Trees (PETs) is successful or failed, this information carries over to top event SA in this tree. If SA is failed in the PETs (i.e., the suction valves t the operating RHR pump close or vortexing occurs as a sult of low level), RHR cooling is lost but the operat has a chance to recover since the pump has not failed. This information is carried as "Operating RHR pump = A" in the transfer states (RHR3, RHR4). If SA is successful, the operating RHR pump = Y or N depending on "R maintained" top event (RHR1, RHR2, RHR5, or RHR6).

SAF = $\overline{SA}$|RHR3 or RHR4

SAS = $\overline{SA}$|RHR1, RHR2, RHR5, or RHR6

For internal/external initiators, it is assumed that suction flow is maintained.

SAS = $\overline{SA}$|Internal/external event.

FAILURE SPLIT FRACTIONS: (mean values)

SAF = 1.0

SAS = 0.0

5.3.5 TOP EVENT TP

SUCCESS: Operator trips operating RHR pump prior to pump damage.

FAILURE: Operator fails to trip operating RHR pump prior to pump damage.

HUMAN ERROR: Operator fails to detect RHR pump operating in degraded suction mode or trips wrong pump (Section 6.2).

$OP1_{TP} = 3.7E-4$

$OP2_{TP} = 1.7E-3$

HARDWARE: RHR flow, temperature, and pressure indicators. The failure frequency of three independent indicators is judged to be negligible.

DEPENDENCIES: This event is used only when top event SA is failed, i.e., when the flow to the operating pump is lost, the operator must trip the pump to prevent pump damage. This dependency is shown explicitly in the Shutdown Transient Tree (i.e., TP is asked only when SA is failed). For internal/ external events, this top event is not needed because SA is assumed always successful for those events. Top event TP is dependent on whether or not the primary system is overpressurized.

$TP1 = \overline{TP}|PC$

$TP2 = \overline{TP}|\overline{PC}$

FAILURE SPLIT FRACTIONS: (mean values)

$TP1 = 3.7E-4$

$TP2 = 1.7E-3$

5.3.6 TOP EVENT OR

SUCCESS: Operator correctly assesses that decay heat removal has been lost and determines appropriate response depending on RCS, RHR, and containment status.

FAILURE: Operator fails to determine that decay heat removal capability has been lost or the operator incorrectly assesses RCS condition or containment.

HUMAN ERROR: Operator fails to determine that decay heat removal has been lost or chooses a decay heat removal mode that is not viable (See Section 6.2).

HARDWARE: RHR flow instrumentation. It is judged that hardware failures are not significant compared to human error due to multiple indicators.

DEPENDENCIES: * Top event OR depends on the RCS condition, the number of RHR trains and support trains available, and previous operator action TP, as follows.

For the RCS filled and closed or in refueling (the time to boil off with no cooling is very long) due to secondary cooling for the RCS filled; due to volume of water in refueling pool for refueling):

- o OR1 = $\overline{OR}$|Procedure or internal/external initiating event - RCS Conditions W (filled) or Y (refueling)

For the RCS drained, loss of the operating RHR train (hardware or vortexing failure), and all support systems available (ASSA) or loss of support Train A:

- o OR2 = $\overline{OR}$|Procedure initiated event - RCS Condition X (drained):

  RHR5/ASSA/or Support Train A failed

  or RHR3/$\overline{TP}$/Support Train A failed or ASSA

  or LPCCA(X), LSWA(X), FL1SG(X), LOSP(X), TCTL(X), FSGA(X), FTBLP(X)/Support Train A failed

For the RCS drained, operating RHR pump vortexing but successfully tripped, and at least one support train available:

o OR3 = $\overline{OR}$|Procedure initiated event - RCS Condition X:

RHR3/TP/ASSA or loss of one Support Train

or RHR4/TP/ASSA or Support Train B failed

For the RCS drained, loss of both RHR trains, and at least one support train available:

o OR4 = $\overline{OR}$|Procedure initiated event - RCS Condition X:

RHR6/ASSA or loss of one Support Train

or RHR5/Support Train B failed

or RHR4/TP/Support Train A failed

or RHR4/$\overline{TP}$/ASSA or loss of one Support Train

or RHR3/$\overline{TP}$/Support B failed

or FETB/Support B failed

For the RCS drained and no support trains available:

o OR5 = $\overline{OR}$|Procedure initiated event - RCS Condition X:

RHR3, RHR4, RHR5, RHR6/No Support Train Available

or LOSP(X), TCTL(X), FTBLP(X)/No Support Trains Avail.

or LPCCA(X), LSWA(X), FSGA(X), FETB(X), FLISG(X)/No Support Trains Avail.

or LPCC(X), LOSW(X), FLSW(X), FETG(X), FLRHR(X), FPAB(X), FPCC(X)

For initiating event with the operating RHR train continuing to function, no operator action is necessary:

o ORS = $\overline{OR}$|Initiated event:

LOSP1, TCTL, FTBLP/ASSA

or LOSP1, TCTL, FTBLP/Support Train B failed

For severe external/internal event:

o ORF = $\overline{OR}|FCRAC$

FAILURE SPLIT FRACTIONS: (point estimates)	OR1	=	1.7E-5
	OR2	=	1.7E-4
	OR3	=	1.7E-4
	OR4	=	4.3E-4
	OR5	=	1.7E-3
	ORS	=	0.0
	ORF	=	1.0

---

* Notation:

"ASSA" = all support systems available

"TP" = top event TP successful

"$\overline{TP}$" = top event TP failed

5.3.7 TOP EVENT RR

SUCCESS: Operator restores previously operating RHR train or starts the standby pump and the RHR train operates for 24 hours.

FAILURE: Operator fails to restore previously operating RHR train and fails to start the standby train or the RHR trains fail to run for 24 hours.

HUMAN ERROR: Operator starts previously operating pump without venting or restoring RCS level or fails to start standby RHR train (included in systems analysis).

HARDWARE: See Section 7.1.2.

DEPENDENCIES: *

RR1 = $\overline{RR}$|Procedure-Initiated Event: RHR1/ASSA/RCS Filled (W,Y)

RR2 = $\overline{RR}$|Procedure-Initiated Event: RHR1/ASSA/RCS Drained (X)

RR3 = $\overline{RR}$|Procedure-Initiated Event: RHR1/Support Train A Failed/ RCS Filled (W,Y)

or RHR3/Support Train A Failed/ RCS Filled (W,Y)

or RHR3/$\overline{TP}$/ASSA/RCS Filled (W,Y)

or RHR5/ASSA/RCS Filled (W,Y)

or RHR5/Support Train A Failed/ RCS Filled (W,Y)

RR4 = $\overline{RR}$|Procedure-Initiated Event: RHR3/Support Train A Failed/ RCS Drained (X)

or RHR3/$\overline{TP}$/Support Train A Failed/ RCS Drained (X)

or RHR5/ASSA/RCS Drained (X)

or RHR5/Support Train A Failed/ RCS Drained (X)

RR5 = $\overline{RR}$|Procedure-Initiated Event: RHR1/Support Train B Failed,

or RHR2/ASSA

or RHR2/Support Train B Failed

for any RCS Condition.

RRZ = $\overline{RR}$|LOSP(X), TCTL(X), FTBLP(X)/ASSA

RR6 = $\overline{RR}$|same as RR6 with RCS Condition W

RRY = $\overline{RR}$|LOSP(X), TCTL(X), FTBLP(X)/Support Train A Failed,

or LPCCA(X), LSWA(X), FSGA(X), FL1SG(X)/Support Train A Failed.

RR7 = $\overline{RR}$|same as RR7 with RCS Condition W.

RR8 = $\overline{RR}$|LOSP, TCTL, FTBLP/Support Train B Failed,

or Procedure-Initiated Event: RHR3/TP/Support Train B Failed.

or RHR4/TP/ASSA

or RHR4/TP/Support Train B failed

for any RCS Condition.

RR9 = $\overline{RR}$|Procedure-Initiated Event: RHR3/TP/ASSA/RCS Filled (W,Y)

RRA = $\overline{RR}$|Procedure-Initiated Event: RHR3/TP/ASSA/RCS Drained (X)

RRF = $\overline{RR}$|Procedure-Initiated Event: RHR2/Support Train A Failed,

or RHR4/Support Train A Failed,

or RHR3/$\overline{TP}$/Support Train B Failed,

or RHR4/$\overline{TP}$/ASSA,

or RHR4/$\overline{TP}$/Support Train B Failed,

or RHR5/Support Train B Failed,

or RHR6/All Support States

or No Support Available,

or LOSP1, TCTL, FTBLP/No Support Trains Available

or LPCCA, LSWA, FSGA, FL1SG/No Support Train Available or LPCC, LOSW, FLSW, FCRAC, FETG, FETB, FPCC, FPAB, FLRHR

FAILURE SPLIT
FRACTIONS:
(mean values)

RR1 = 4.4E-4

RR2 = 2.3E-4

RR3 = 1.2E-1

RR4 = 8.9E-3

RR5 = 9.3E-4

RRZ = 6.3E-4

RR6 = 2.3E-3

RRY = 8.9E-3

RR7 = 1.2E-1

RR8 = 7.6E-3

RR9 = 3.[illegible]E-3

RRA = 6.6E-4

RRF = 1.0

---

* Notation:

"ASSA" = All Support Systems Available

5.3.8 TOP EVENT LC

SUCCESS: Operator establishes long term cooling with secondary cooling or feed and bleed.

FAILURE: Operator fails to establish long term cooling or hardware failure of secondary cooling and feed and bleed.

HUMAN ERROR: Included in systems analysis.

HARDWARE: See Sections 7.5.1 (Secondary Cooling) and 7.5.4 (Feed and Bleed Cooling).

DEPENDENCIES:

LC1 = $\overline{LC}|$Procedure-Initiated event: ASSA, RCS Open (X); or LOSP(X), TCTL(X), FTBLP(X), FLRHR(X): ASSA, RCS Open (X).

= SCF * FB1

LC2 = $\overline{LC}|$Procedure-Initiated event: Support Train A Failed, RCS Open (X); or LOSP(X), TCTL(X), FTBLP(X), LPCCA(X), LSWA(X), FETG(X), FSGA(X), FL1SG(X), FLRHR(X): Support Train A Failed, RCS Open (X).

= SCF * FB3

LC3 = $\overline{LC}|$Procedure-Initiated event: Support Train B Failed, RCS Open (X); or LOSP(X), TCTL(X), FTBLP(X), FLRHR(X), FETB(X): Support Train B Failed, RCS Open (X).

= SCF * FB2

LC4 = $\overline{LC}|$Procedure-Initiated event: No Support Train Avail., RCS Open (X); or LOSP(X), TCTL(X), FTBLP(X), FLRHR(X), FSGA(X), FETB(X), LPCCA(X), LSWA(X), FETG(X), FPAB(X), FL1SG(X): No Support Train Avail., RCS Open (X); or FLSW(X), LPCC(X), LOSW(X), FPCC(X): RCS Open (X).

= SCF * FB4

LC5 = $\overline{LC}|$LC1 except RCS Closed (W).

= SC1 * FB1

LC6 = $\overline{LC}|$LC2 except RCS Closed (W).

= SC2 * FB3

LC7 = $\overline{LC}$|LC3 except RCS Closed (W).

= SC2 * FB2

LC8 = $\overline{LC}$|LC4 except RCS Closed (W).

= SC3 * FBF

LC9 = $\overline{LC}$|Procedure-Initiated event: RCS at Refueling Level (Y)

= SCF * FB5

LCF = $\overline{LC}$|FCRAC

= guaranteed failed

FAILURE SPLIT
FRACTIONS:
(mean values)

LC1 = 2.3E-3

LC2 = 9.0E-3

LC3 = 2.3E-3

LC4 = 1.8E-2

LC5 = 1.4E-7

LC6 = 5.5E-7

LC7 = 1.4E-7

LC8 = 8.7E-4

LC9 = 1.0E-5

5.3.9 TOP EVENT EH

SUCCESS: The equipment hatch is on and secured or hatch is off but is reinstalled prior to core damage and other large penetrations are closed.

FAILURE: The equipment hatch is open and not recovered at the time of core damage or other large penetrations are not closed.

HUMAN ERROR: See Sections 6.4.2 and 10.1.

HARDWARE: Hardware failures include the polar crane motors fail to start and the purge valves fail to close on demand. (See Section 10.1).

DEPENDENCIES: Top event EH depends on the RCS condition (assumes hatch is not off for Condition X), the availability of offsite power (to operate the crane), and the time available for action. (See Section 10.1).

FAILURE SPLIT FRACTIONS: (mean values)

EH1 = 2.9E-3

EH2 = 5.1E-3

EH3 = 2.1E-3

EH4 = 1.1E-4

EH5 = 3.8E-2

EH6 = 3.3E-2

EH7 = 3.5E-3

5.3.10 TOP EVENT SP

SUCCESS: Operator identifies all small containment penetrations that are not isolated and successfully closes them.

FAILURE: Small containment penetrations are not isolated.

HUMAN ERROR: Operator fails to identify all containment penetrations that are open (see Sections 6.4.2 and 10.1).

HARDWARE: It is assumed that human errors dominate. Valve failure to manually close is relatively low frequency.

DEPENDENCIES: If a large penetration is open ($\overline{EH}$), the status of small penetrations in containment is inconsequential and top event SP is not questioned. SP also depends on the RCS Condition:

$SP1 = \overline{SP}|\text{Condition W}$

$SP2 = \overline{SP}|\text{Condition X}$

FAILURE SPLIT FRACTIONS: (mean values)

SP1 = 1.7E-2

SP2 = 4.0E-2

5.4 Plant Model: LOCA Tree Top Event Quantification

The top events in the LOCA tree are quantified for each LOCA initiator and for possible support states. The top event split fractions are summarized in Table 5-8 and are described in detail below.

5.4.1 TOP EVENT OD

SUCCESS: Operator detects LOCA soon after its initiation (0-10 min.).

FAILURE: Operator fails to detect LOCA prior to substantial inventory loss from the primary system.

HUMAN ERROR: See Section 6.2.

HARDWARE FAILURES: There are multiple, independent alarms/indications of LOCA. Hardware failures are assumed to be negligible.

DEPENDENCIES: For LOCAs L1, L5, L6, and LS, the operator has multiple alarms and indications of a LOCA.

$OD1 = \overline{OD}|L1, L5, L6, LS$

For L3, the operator must detect over-draining of the RCS (i.e., no alarms) but is alert because of the plant condition.

$OD2 = \overline{OD}|L3$

For LP, the operator must detect the RHR pump seal failure from indirect indications (RHR vault sump alarm). The leak is small so more time is available for detection.

$OD3 = \overline{OD}|LP$

FAILURE SPLIT FRACTIONS: (mean values)

OD1 = 1.6E-3

OD2 = 2.7E-4

OD3 = 1.6E-3

5.4.2 TOP EVENT IR

SUCCESS: Operator isolates RHR within 30 minutes by closing RHR suction valves RH-V-87 or RH-V-23.

FAILURE: Operator fails to isolate the RHR suction lines or the suction valves fail to close on demand.

HUMAN ERROR: Operators fail to close RHR suction valves RH-V-87 or RH-V-23 (see Section 6.2).

$$OP1_{IR} = \overline{IR}|L1, LP = 3.8E-3$$

$$OP2_{IR} = \overline{IR}|L3 = 2.7E-4$$

HARDWARE FAILURES: RHR suction valves RH-V-87 or RH-V-23 fail to close.

$$HW1_{IR} = MOV = 4.3E-3$$

where:

MOV = MOV fails to close on demand

DEPENDENCIES: For LS, the time to isolate RHR before significant inventory loss is much shorter than 30 minutes. It is assumed, with the confusion surrounding the event and the short time available, that top event IR is guaranteed failure.

$$IRF = \overline{IR}|LS$$

For L5 and L6, e operator will not isolate the RHR since the inventory cannot drain below the top of the vessel flange. Thus, for these events, IR is not not necessary, and is modeled as a guaranteed success.

$$IRS = \overline{IR}|L5, L6$$

For L1, L3, and LP, the operator can isolate RHR at the main control board as long as both essential ac electrical trains are available. With offsite power available, it is assumed that electric power is available. The operator action to close the RHR suction valves is modeled from the control room:

$$IR1 = \overline{IR}|L1, LP = HW1_{IR} + OP1_{IR}$$

$$IR2 = \overline{IR}|L3 = HW1_{IR} + OP2_{IR}$$

FAILURE SPLIT
FRACTIONS:
(mean values)

IR1 = 8.1E-3

IR2 = 4.6E-4

IRF = 1.0

IRS = 0.0

5.4.3 TOP EVENT MU

SUCCESS: Operator increases RCS makeup flow to match inventory loss out the break.

FAILURE: Inventory loss is greater than makeup.

HUMAN ERROR: (See Dependencies).

HARDWARE FAILURES: Failure of operating charging pump to continue to operate or charging pump fails to automatically transfer from VCT to RWST or RWST supply valve fails to open on demand or the VCT suction valves fail to close.

$$HW1_{MU} = P_R * 6 \text{ hr} + LC * LC + RWA + (VCTA * VCTB + VCTA * BETA)$$

$$= 4.70E-3$$

where:

P_R = fails to run = 3.36E-5/hr

LC = VCT level control relay fails to operate on demand

= 2.41E-4

RWA = RWST MOV fails to open on demand

= 4.30E-3

VCTA = VCT suction MOV fails to close on demand

= 4.30E-3

BETA = common cause beta factor for MOVs

= 4.23E-2

DEPENDENCIES: For large LOCAs (L3, LS), it is assumed that top event MU is guaranteed failed because the inventory loss cannot be made up with one charging pump.

$$MUF = \overline{MU}|L3, LS$$

For L5 and L6, the operator does not need to increase charging since the RCS inventory cannot drop below the top of the flange. Thus, this event is not necesary and is modeled as guaranteed success.

$$MUS = \overline{MU} | L5, L6$$

For L1 and LP, the LOCA was caused by overcharging. In response to the LOCA, the operator will permit the charging pump to continue to makeup to the primary system for [illegible] hours (i.e., no operator actions needed). It is assumed that only the operating charging pump is available. (Time is not available to rack-in the breaker for the other pump).

$MU1 = \overline{MU} | (L1, LP)$, * (ASSA or Support Train B failed)

$MUF = \overline{MU} | (L1, LP)$, * (Support Train A failed or All Support Trains failed)

FAILURE SPLIT FRACTIONS:
(mean values)

$MU1 = HW1_{MU} = 4.70E-3$

$MUF = 1.0$

$MUS = 0.0$

5.4.4 TOP EVENT TP

SUCCESS: Operator trips running RHR pump before pump damage occurs from loss of suction.

FAILURE: The operator fails to trip the running RHR pump before pump damage occurs from loss of suction.

HUMAN ERROR: Operators fail to trip running RHR pump before pump damage occurs from loss of suction (see Section 6.2).

HARDWARE FAILURES: None.

DEPENDENCIES: For L5 and L6, it is not necessary for the operators to trip the pump since the RCS inventory cannot drain below the vessel flange. Also, for L3, the RHR pumps are not yet running per procedure. This is modeled as guaranteed successful.

$$TPS = \overline{TP}|L5, L6$$

For L1 and LP with IR failed and MU successful, it is not necessary to trip the pumps. One charging pump can maintain level.

$$TPS = \overline{TP}|(L1, LP) * \overline{IR}, * MU$$

For L1, L3, and LP with IR successful, the operator must trip the pump in a short time to prevent overheating. He is alert due to success of IR.

$$TPA = \overline{TP}|(L1, LP) * IR$$

For L1, LP and LS with IR failed and MU failed, the operator must trip the pump before it fails from vortexing. The operator is in a high stress level because of previous errors or because of short time available(LS).

$$TPB = \overline{TP}|(L1, LP) * \overline{IR} * \overline{MU}$$

For LS, insufficient time is available to trip the operating RHR pump before vortexing. Thus, T^P is guaranteed failure.

$$TPF = \overline{TP}|LS$$

FAILURE SPLIT
FRACTIONS:
(mean values)

TPA = 1.0E-4

TPB = 2.2E-1

TPF = 1.0

TPS = 0.0

5.4.5 TOP EVENT OL

SUCCESS: Operators determine actions required to restore and maintain RCS heat removal before core damage occurs.

FAILURE: Operators fail to determine actions to restore RCS heat removal before core damage occurs.

HUMAN ERROR: See Section 6.2.

HARDWARE FAILURES: None.

DEPENDENCIES: For L1 and LP, if the operator successfully isolates RHR (IR), he has a number of hours with passive secondary cooling to get RHR or alternate cooling operable.

$$OL1 = \overline{OL}|(L1,\ LP) * IR$$

For L5 and L6, with at least one support system available:

$$OL2 = \overline{OL}|L5,\ L6 * (\text{ASSA or Single Support Train Avail.})$$

For L5 and L6, with no support systems available:

$$OL3 = \overline{OL}|L5,\ L6 * (\text{No Support Trains Avail.})$$

For L3, if RHR can be used and if the operator has successfully isolated RHR (IR):

$$OL4 = \overline{OL}|L3 * IR$$

For LS with at least one support train available:

$$OL5 = \overline{OL}|(LS) * (\text{ASSA or Single Support Train Failed})$$

For L1 and LP, if the operator has not successfully isolated RHR:

$$OL6 = \overline{OL}|(L1,\ LP) * \overline{IR} * \text{ASSA or Single Support Train Avail.}$$

For any LOCA except L3, if the initial detection (OD) is failed.

$$OL7 = \overline{OL}|\overline{OD}$$

For L1 and LP with IR or OD failed or for LS, with no support trains available, it is assumed that there are no long term cooling options.

$$OLF = \overline{OL}|(L1, LP) * (\overline{IR} \text{ or } \overline{OD}) * \text{No Support trains available,}$$

$$\text{or } LS * \text{No Support trains available}$$

Also, for L3 with IR or OD failed, a short time is available for recovery. It is assumed to be guaranteed failure.

$$OLF = \overline{OL}|L3 * (\overline{IR} \text{ or } \overline{OD})$$

FAILURE SPLIT FRACTIONS:

OL1 = 5.0E-5

OL2 = 2.6E-4

OL3 = 6.5E-4

OL4 = 6.5E-5

OL5 = 8.5E-4

OL6 = 4.3E-4

OL7 = 9.5E-4

OLF = 1.0

5.4.6 TOP EVENT RR

SUCCESS: Operator restores normal RHR cooling by reopening RHR suction valves RH-V-87 and 88 or RH-V-22 and 23 and restarting at least one RHR pump.

FAILURE: RHR shutdown cooling is not restored.

HUMAN ERROR: Operator fails to align RHR shutdown cooling correctly (included in systems analysis).

HARDWARE FAILURES: See Sections 7.1.2 and 5.3.7.

DEPENDENCIES: Top event RR depends on RCS conditions [RHR planned maintenance occurs only when RCS is filled (W) or during refueling (Y)]; support systems available; previous top event IR (except L5 and L6 where the level does not drop below the top of the flange); and previous top event TP for those LOCAs for which the operating train can be used (L3, L5).

RR1 = $\overline{RR}$|L5 * ASSA or L6 * ASSA

RR3 = $\overline{RR}$|L5 * Support Train A failed,

or L6 * Support Train A failed,

or L1 * IR * ASSA

or L1 * IR * Support Train A failed,

or LP * IR * ASSA

or LP * IR * Support Train A failed

RR5 = $\overline{RR}$|L5 * Support Train B failed,

or L6 * Support Train B failed,

RRF = $\overline{RR}$|No Support Trains Available,

or L1 * IR * Support Train B failed

or L1 * $\overline{IR}$

or LP * IR * Support Train B failed

or $LP * \overline{IR}$

or LS

or L3

FAILURE SPLIT
FRACTIONS:
(mean values)

RR1 = 4.4E-4

RR2 = 2.3E-4

RR3 = 1.2E-1

RR4 = 8.9E-3

RR5 = 9.3E-4

RRF = 1.0

5.4.7 TOP EVENT LC

SUCCESS: Operator established long term cooling with secondary cooling or feed and bleed.

FAILURE: Operator fails to establish long term cooling or hardware failure of secondary cooling and feed and bleed.

HUMAN ERROR: Included in systems analysis.

HARDWARE: See Sections 7.5.1 (Secondary Cooling) and 7.5.4 (Feed and Bleed Cooling).

DEPENDENCIES:

LC1 = $\overline{LC}$|(L5, L6) * ASSA

or LP * $\overline{IR}$ * MU * ASSA

= FB1

LC2 = $\overline{LC}$|(L5, L6) * Support Train A failed,

or LP * $\overline{IR}$ * MU * Support Train A failed

= FB3

LC3 = $\overline{LC}$|(L5, L6) * Support Train B failed

or LP * $\overline{IR}$ * MU * Support Train B failed,

= FB2

LC5 = $\overline{LC}$|(L1, LP, L3) * IR * ASSA

= SC1 * FB1

LC6 = $\overline{LC}$|(L1, L3, LP) * IR * Support Train A failed

= SC2 * FB3

LC7 = $\overline{LC}$|(L1, L3, LP) * IR * Support Train B failed

= SC2 * FB2

LCA = LC|L1 * $\overline{IR}$ * MU * (ASSA or Support Train A failed)

= LR2

LCB = $LC|L1 * \overline{IR} * \overline{MU}$ * (ASSA or Support Train A failed)

= LP2 + LR2

LCC = $\overline{LC}|LS$ * (ASSA or Support Train A Failed)

= LR2

LCF = $\overline{LC}|$(L1, L3, L5, L6, LP, LS) * No Support Trains available

or L1 * $\overline{IR}$ * Support Train B failed

or LS * Support Train B Failed

or LP * $\overline{IR}$ * $\overline{MU}$

or L3 * $\overline{IR}$

FAILURE SPLIT FRACTIONS:
(mean values)

LC1 = 2.3E-3

LC2 = 9.0E-3

LC3 = 2.3E-3

LC5 = 1.4E-7

LC6 = 5.5E-7

LC7 = 1.4E-7

LCA = 1.2E-1

LCB = 2.4E-1

LCC = 1.2E-1

LCF = 1.0

5.4.8 TOP EVENT EH

SUCCESS:	The equipment hatch is on and secured or hatch is off but is replaced prior to core damage and other large penetrations are cloosed.
FAILURE:	The equipment hatch is open and not recovered at the time of core damage or other large penetrations are not closed.
HUMAN ERROR:	See Sections 6.4.2 and 10.1
HARDWARE FAILURES:	See Section 10.1
DEPENDENCIES:	(See Section 10.1).

$EH2 = \overline{EH}|LOCA\ L3,\ L5,\ L6$

$EH5 = \overline{EH}|LOCA\ L1,\ LP,\ LS$

FAILURE SPLIT FRACTIONS:

EH2 = 5.1E-3

EH5 = 3.8E-2

5.4.9 TOP EVENT SP

SUCCESS: Operator identifies all small containment penetrations that are not isolated and successfully closes them.

FAILURE: Small containment penetrations are not isolated.

HUMAN ERROR: Operator fails to identify all containment penetrations that are open (see Sections 6.4.2 and 10.1).

HARDWARE FAILURES: It is assumed that human errors dominate. Valve failure to manually close is a relatively low frequency.

DEPENDENCIES: If a large penetration is open ($\overline{EH}$), the status of small penetrations in containment is inconsequential and thus top event SP is not questioned. Also SP is guaranteed failed for LOCAs LP and L3 which provide a path outside the containment.

SP2 = $\overline{SP}$|LOCA L1, L5, L6, LS

SPF = $\overline{SP}$|LOCA LP, L3

FAILURE SPLIT FRACTIONS: (mean values)

SP2 = 4.0E-2

SPF = 1.0

5.5 Procedure-Initiated Events Model

The procedure-initiated events model, described in Section 4, is quantified to obtain the annual frequency of occurrence of plant transient events. These events include procedural errors and hardware failures which cause loss or degradation of RHR, overpressurization of the RHR-RCS piping, or loss of primary inventory (LOCA).

The "initiating events" for the procedure trees are specific types of plant shutdown as follows:

Case A

Non-drained maintenance shutdowns; mean annual frequency = 3.4 per year; mean duration = 319 hours per outage. These outages tend to be short outages which occur throughout the year involving minor repair and reactor trip recovery.

Case B

Drained maintenance shutdown: mean annual frequency = 0.45 per year; mean duration = 1115 hoursper outage. These are very long but infrequent outages involving repair procedures which requires the primary system to be drained. This activity would typically occur during a refueling outage so this is an unplanned shutdown with a relatively fresh core.

Case C

Refueling shutdowns: mean annual frequency = 0.83 per year; mean duration = 1961 hours per outage. These outages include refueling, which takes a small fraction of the time, and post-refueling maintenance as well as numerous surveillances.

The procedure tree end states are either a plant transient event or a stable plant condition in which the regular plant evolutions would continue. The procedural transient end states become the initiating events to the transient or LOCA trees. The procedural end states are coded to describe the key factors of the sequence, as summarized below (also see Section 4).

1st Factor: RCS Condition

W = RcS full and closed; secondary cooling available
X = RcS drained to vessel flange or hot leg and RCS vented
Y = RCS at refueling level

2nd Factor: Condition of RHR Pump Trains

1 - both pumps operable
2 - standby pump inoperable
3 - "operating" pump cavitating
4 - "operating" pump cavitating, standby pump inoperable
5 - "operating" pump failed, standby pump operable
6 - both pumps inoperable

3rd Factor: Overpressure Status

A - overpressure event with 2 or more relief paths
B - overpressure event with 1 relief path
C - overpressure event with no relief paths
N - no overpressure event

Table 5-9 lists the frequency contribution to each procedural end state from each Case and Tree.

Tables 5-10, 5-11, and 5-12 list the split fractions used to quantify each procedural tree for Cases A, B,f and C respectively. As explained in Section 4, Case A includes Trees 1 and 6; Case B includes Trees 1, 2, 5, and 6; Case C includes Trees 1 through 6.

Table 5-13 provides a summary of the quantification for each procedural split fraction. The details of the split fraction quantification are included in the following six subsections.

Sections 5.5.1 through 5.5.6 cover the following trees:

- o Tree 1 - Cooldown
- o Tree 2 - RCS Drain
- o Tree 3 - Refueling Cavity Fill
- o Tree 4 - Refueling Cavity Drain
- o Tree 5 - RCS Fill
- o Tree 6 - Startup

5.5.1 Tree 1 - Cooldown Event Tree

The description and quantification of split fractions in Tree 1 are as follows.

5.5.1 (1) Top Event RV

SUCCESS: Operator opens RHR suction valves RC-V22 and V23 (or V87 and V88) after RCS pressure decreases to less than 450 psig.

FAILURE: The RHR suction valves open at RCS pressure greater than 450 psig (the setpoint of the RHR suction relief valves) due to suction valves inadvertently transferring open, i.e., primary hardware fault, or due to a command fault. The command fault is either (1) the operator opens the suction valves prematurely given proper pressure indication (PT-403 and PT-405), and the pressure interlocks (which prevent the valves from being opened above 365 psig) fail; or (2) the operator opens the suction valves prematurely given faulty pressure indication (PT-403 and PT-405) and the pressure interlocks are satisfied due to the failure of PT-403 and PT-405.

OPERATOR ACTION: See Section 6.3.

$OP1_{RV}$ = 3.8E-3 - Operator opens suction valves prematurely, given proper indication.

$OP2_{RV}$ = 1.0 - Operator opens suction valves prematurely, given faulty indication.

$OP3_{RV}$ = 4.5E-2 - Operator fails to detect pressure transmitter failure.

HARDWARE: See Section Section 7.5.5

(1) Primary hardware failure of the suction valves to open is the frequency of both suction MOVs in either path to transfer open during the mission time for this event. This failure sequence is neglected because of the low frequency of the valve failure (9.27E-8/hr) and the short mission time (less than 50 hr).

(2) Failure of the pressure transmitters PT-403 and PT-405 to operate between the time of the last surveillance (18 months) and not detected is quantified as follows:

$$HW_{PT} = (PT * PT + PT * BETA) * OP3_{RV}$$

$$= 1.0E-3$$

where:

PT = pressure transmitters fail to operate for the mission time (Z1TRPR in Table 9-1).

= 7.6E-6/hr * 18 months

BETA = beta factor for common cause failure of pressure transmitters (e.g., miscalibration)

= 0.125 (generic value) (ZBGN1A in Table 9-2)

$OP3_{RV}$ = 4.5E-2

(3) Failure of the RHR suction valve interlocks to operate. This failure mode is negligible because the interlock must energize to operate which is not a credible failure mode.

DEPENDENCIES: None

FAILURE SPLIT FRACTIONS:

$$RV1 = OP2_{RV} * HW_{PT} = 1.0E-3$$

5.5.1 (2) Top Event CT

SUCCESS: The RHR suction valves for both trains are opened and cross-train depowered (i.e., for Train A suction path, the B valve is depowered, etc.).

FAILURE: The RHR train suction valves are opened but the motor starters are not depowered for both of the cross-train valves.

OPERATOR ACTION: Operator opens the valves but fails to depower the cross train motor starters for the valves. The indication for the valves in the control room include indicating lights for power available and stem mounted limit switches for valve position. (See Section 6.3).

$$OP_{CT} = 1.7E-2$$

HARDWARE: None

DEPENDENCES: None

FAILURE SPLIT FRACTIONS:

$$CT1 = OP_{CT} = 1.7E-2$$

5.5.1 (3) Top Event RI

SUCCESS: RHR shutdown cooling is successfully initiated with one of two trains of RHR.

FAILURE: Neither RHR train functions to remove decay heat from the RCS.

OPERATOR ACTION: Operator fails to start an RHR pump and to set up correct alignment or operator fails to start the standby pump if the first pump fails to start. The operator action is included with the hardware in the RHR systems analysis.

HARDWARE: See RHR systems analysis (Section 7.1).

DEPENDENCES: None

FAILURE SPLIT FRACTIONS:

RI1 = 4.2E-4

5.5.1 (4) Top Event LT

SUCCESS: LTOP circuitry is available to at least one PORV.

FAILURE: Both PORVs are inoperable to respond to low temperature overpressure conditions.

OPERATOR ACTION: None (LTOP is self-arming at 329°F).

HARDWARE: See Section 7.5.5.

PT-403 and PT-405 or the pressure programmers or the bistables fail to operate during the mission time. The hardware unavailability is as follows:

$$HW = (PT + PP + BS)_A * (PT + PP + BS)_B + BETA * PT$$

where:

PT = pressure transmitter fails low (ZITRPR in Table 9-1) for mission time T_M (pressure transmitters are assumed to be verified operable at the beginning of Tree 1, in top event RV).

$= 7.6E-6 * T_M$

PP = pressure programmer fails high (ZISMDR in Table 9-1) for the mission time T_M (assuming the monthly channel check was done prior or during Tree 1).

$= 2.94E-6 * T_M$

BS = bistable fails low (ZISWB1) for the mission time T_M (conservative time because bistable alarms on loss of power).

$= 2.21E-6 * T_M$

BETA = beta factor common cause failure of pressure transmitters (ZBGN1A in Table 9-2).

= 0.125 (generic value)

Thus,

$$HW1 = \overline{HW}|\text{Case A } (T_M = 295 \text{ hr}) = 2.95E-4$$

$HW2 = \overline{HW}|\text{Case B } (T_M = 31 \text{ hr}) = 2.96E-5$

$HW3 = \overline{HW}|\text{Case C } (T_M = 50 \text{ hr}) = 4.79E-5$

DEPENDENCES:

$LT1 = \overline{LT}|\text{Case A} = HW1$

$LT2 = \overline{LT}|\text{Case B} = HW2$

$LT3 = \overline{LT}|\text{Case C} = HW3$

FAILURE SPLIT FRACTIONS:

LT1 = 3.0E-4

LT2 = 3.0E-5

LT3 = 4.8E-5

5.5.1 (5) Top Event RM

SUCCESS: Decay heat removal is maintained by the preferred RHR train for the mission time.

FAILURE: The preferred train of RHR fails to continue to operate for the mission time.

OPERATOR ACTION: None.

HARDWARE: See RHR system analysis (Section 7.1).

DEPENDENCIES:

$RM1 = \overline{RM}|$Case A (non-drained maintenance),

$T_M = 295$ hr

$RM2 = \overline{RM}|$Case B (drained maintenance),

$T_M = 31$ hr

$RM3 = \overline{RM}|$Case C (refueling),

$T_M = 50$ hr

FAILURE SPLIT FRACTIONS:

RM1 = 1.1E-2

RM2 = 1.2E-3

RM3 = 1.9E-3

5.5.1 (6) Top Event SA

SUCCESS: Suction flow is maintained in the operating RHR train.

FAILURE: RHR suction flow is lost via valve closure.

OPERATOR ACTION: Failure to remove power from RHR suction valves while performing test or maintenance on wide range RCS pressure transmitters PT-403, 405. See Section 6.3. This is assumed to occur for Case C only.

$OP1_{SA} = \overline{SA}|CT$, Case C = 8.3E-3

$OP2_{SA} = \overline{SA}|\overline{CT}$, Case C = 1.1E-1

HARDWARE: See Section 7.5.5. It is conservatively assumed that top event LT is failed, in the quantification of the hardware contribution to SA. Thus,

$HW = \overline{SA}|\overline{LT} = (PT405 + PB405 + K735) * T_M$

where:

PB405 = bistable fails low during operation

= 2.2E-6/hr (ZISWBI in Table 9-1)

K735 = relay fails closed

= 4.2E-7/hr (ZIRL1R in Table 9-1)

PT405 = pressure transmitter fails high

= 7.6E-6/hr (ZITRPR in Table 9-1)

The mission time is:

T_M (Case A) = 295 hr

T_M (Case B) = 31 hr

T_M (Case C) = 50 hr

Thus, HWA = $\overline{SA}$|Case A = 3.0E-3

HWB = $\overline{SA}$|Case B = 3.2E-4

HWC = $\overline{SA}$|Case C = 5.1E-4

DEPENDENCIES:

$SA1 = \overline{SA} | \text{Case A}$

$SA2 = \overline{SA} | \text{Case B}$

$SA3 = \overline{SA} | CT, \text{Case C}$

$SA4 = \overline{SA} | \overline{CT}, \text{Case C}$

FAILURE SPLIT FRACTIONS:

$SA1 = HWA = 3.0E-3$

$SA2 = HWB = 3.2E-4$

$SA3 = OP1_{SA} + HWC = 8.8E-3$

$SA4 = OP2_{SA} + HWC = 1.1E-1$

5.5.1 (7) Top Event NC

SUCCESS: Charging flow is balanced by letdown flow and RCS shrink.

FAILURE: Charging flow is in excess of letdown flow and RCS shrink, causing an overpressurization transient. This can occur due to hardware failures cause excess charging and the operator fails to recover before an overpressure event:

$$\overline{NC} = HW_{NC} * NR_{NC}$$

OPERATOR ACTION: Balancing, charging, and letdown is controlled automatically by CS-PCV-131.

Operator action is included in recovery from hardware-induced excess charging events (see Section 6.3.1).

$$NR1_{NC} = 0.27$$

$$NR2_{NC} = 0.11$$

$$NR3_{NC} = 0.24$$

HARDWARE: Hardware-induced excess charging HW_{NC} can occur in three general ways:

(1) inadvertent SI signal which isolates letdown and causes maximum charging flow from one pump (ISI),
(2) CS - PCV-131 failing closed causing isolation of letdown (V131),
(3) CS - FCV-121 failing open causing maximum charging flow (V121), and

These hardware failures can be quantified as follows:

(1) Excess charging can occur from an inadvertent SI and operator failure to respond before pressurization to 450 psig. Thus:

$$ISI = F_{ISI} * NR_{NC}$$

$$ISI(1) = ISI|\text{Case A (bubble)} = F_{ISI} * NR1_{NC}$$

$$= 2.7E-4$$

ISI(2) = ISI|Case B or C (pressurizer solid)

$= F_{ISI} * NRF_{NC}$

= 1.0E-3

where:

F_{ISI} = frequency of inadvertent SI signal during shutdown

= 1.0 E-3 (conser[illegible]ive from NSAC-84 p. C-5a)

[illegible] prcbab[illegible]lity of non-r[illegible]covery for Case A; operator failure to respond to inadvertent SI, giver [illegible]ressurizer bubble prior to pressurization to 450 psig.

= 0.27 (see Section 6.3.1)

NRF_{NC} = probability of non-recovery fo[illegible] Cases B,C

= 1.0

(2) Excess charging can occur due to letdown isolation from closure of PCV-131 which is a fail open AOV. The only credible transfer closed failure mode is for pressure transmitter PT-131, which controls V131, to give a false open signal to the valve.

$$V131 = PT * T_M * NR_{NC}$$

where:

PT = 7.6 E-6/hr (ZITRPR in Table 9-1)

T_M = 295 hours for Case A,
31 hours for Case B,
50 hours for Case C

NRF_{NC} = 1.0 given Case B,C (pressurizer solid)

$NR2_{NC}$ = 0.11 given Case A (bubble) - (see Section 6.3.1)

Thus, V131(1) = V131|Case A = 2.47E-4

V131(2) = V131|Case B = 2.36E-4

V131(3) = V131|Case C = 3.80E-4

(3) Excess charging can occur due to inadvertent increased charging from transferring full open of FCV-121, which is a fail open AOV. It can fail by transferring to its failed position (AOT) or by getting a false signal from a failed flow transmitter. Thus,

$$V121 = (AOT + FT) * T_M * NR_{NC}$$

where:

$AOT = 2.67\ E\text{-}7/hr$ (ZIVAOT in Table 9-1)

$FT = 6.25\ E\text{-}6/hr$ (ZITRFR in Table 9-1)

T_M = 295 hours for Case A
31 hours for Case B
50 hours for Case C

NRF_{NC} = 1.0 given Case B,C (no recovery)

$NR3_{NC}$ = 0.24 given Case A - (see Section 6.3.1)

Thus,

$$V121(1) = V121|\text{Case A} = 4.61E\text{-}4$$

$$V121(2) = V121|\text{Case B} = 2.02E\text{-}4$$

$$V121(3) = V121|\text{Case C} = 3.26E\text{-}4$$

DEPENDENCIES: Top event NC is dependent on Case (A,B,C) due to the different mission times and the different levels in the pressurizer (Case A - bubble, Case B and C - solid).

$$NC1 = \overline{NC}|\text{Case A} = ISI(1) + V131(1) + V121(1)$$

$$NC2 = \overline{NC}|\text{Case B} = ISI(2) + V131(2) + V121(2)$$

$$NC3 = \overline{NC}|\text{Case C} = ISI(2) + V131(3) + V121(3)$$

FAILURE SPLIT FRACTIONS:

NC1 = 9.8E-4

NC2 = 1.4E-3

NC3 = 1.7E-3

5.5.2 Tree 2 RCS Draindown

The description and quantification of split fractions in Tree 2 are as follows:

5.5.2 (1) Top Event TV

SUCCESS: The temporary level transmitter is installed and agrees with LI-462 pressurizer level indication at pressurizer level about 20%.

FAILURE: The temporary level transmitter is installed incorrectly and does not read correctly at pressurizer level of 20% and the operator fails to detect the difference.

HUMAN: Operator installs the temporary level transmitter incorrectly and operator fails to detect that there is a difference between the reading for LI-462 and the transmitter indication. (See Section 6.3).

$$OP_{TV} = 1.0E-3$$

HARDWARE: None.

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

TV1 = 1.0E-3

5.5.2 (2) Top Event DR

SUCCESS: Operator reduces RHR flow from 3000 gpm to about 1000 gpm to prevent a vortex from being formed.

FAILURE: Operator fails to reduce RHR flow when drained to mid plane of hot leg nozzle (drained maintenance), resulting in loss of cooling due to vortexing.

HUMAN: Operator fails to reduce flow. (See Section 6.3).

$$OP_{DR} = 3.1E-3$$

HARDWARE: None.

DEPENDENCIES: DR1 = $\overline{DR}|$Case B (Drained Maintenance - drained to hot leg).

DR2 = $\overline{DR}|$Case C (Refueling - drained to top of vessel).

FAILURE SPLIT FRACTIONS:

DR1 = 3.1E-3

DR2 = 0.0

5.5.2 (3) TOP EVENT LM

SUCCESS: Level is initially maintained at ~7' below flange (for drained maintenance) or at ~4" below flange (for refueling).

FAILURE: Level is dropped sufficiently low to cause a vortex in RHR suction line and subsequent failure of the operating RHR pump.

HUMAN: Operator fails to control level. (See Section 6.3).

$OP1_{LM}$ = 8.6E-4

$OP1_{LM}$ = 3.1E-4

HARDWARE: None.

DEPENDENCIES: During drained maintenance, the level is maintained lower than during refueling. Thus, the chance of vortexing due to operator error is greater.

$\overline{LM}|$Case B = LM1

$\overline{LM}|$Case C = LM2

FAILURE SPLIT FRACTIONS:

LM1 = $OP1_{LM}$ = 8.6E-4

LM2 = $OP2_{LM}$ = 3.1E-4

5.5.2 (4) <u>Top Event VA</u>

SUCCESS: RCS is vented to containment atmosphere and LI-9405 is capable of operating correctly.

FAILURE: RCS is not vented to containment atmosphere. This would have resulted in LI-9405 giving a false high level. The addition of delta pressure as a level monitor eliminates this failure.

HUMAN: Operator fails to open RCS vent valve. (See Section 6.3).

$$OP_{VA} = 0.0$$

HARDWARE: None.

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

VA1 = 0.0

5.5.2 (5) <u>Top Event 10</u>

SUCCESS: LI-9405 is operable and indicating correct RCS vessel level.

FAILURE: LI-9405 is not functioning correctly and is indicating an incorrect higher vessel level.

HUMAN: None.

HARDWARE: LI-9405 has failed high (LT = ZITRLR in Table 9-1) for a mission time (T_M) equal to the time in drained down condition. It is assumed that for the entire time in Tree 2 the RCS is drained down.

DEPENDENCIES:

$IO1 = \overline{IO}|\text{Case B} - (T_M = 959 \text{ hr})$

$IO2 = \overline{IO}|\text{Case C} - (T_M = 47 \text{ hr})$

FAILURE SPLIT FRACTIONS:

$$IO1 = LT * T_M = (1.57\text{ E-5/hr}) * 959 \text{ hr}$$
$$= 1.5\text{E-2}$$
$$IO2 = LT * T_M = (1.57\text{ E-5/hr}) * 47 \text{ hr}$$
$$= 7.4\text{E-4}$$

5.5.2 (6) Top Event SA

SUCCESS: Suction flow is maintained in the operating RHR train.

FAILURE: RHR suction flow is lost via valve closure or vortexing at low level.

HUMAN: Operator fails to control level. (See Section 6.3).

$$OP3_{SA} = \overline{OP}|\text{Case B} = 2.2E-2$$

$$OP4_{SA} = \overline{OP}|\text{Case C} = 3.9E-4$$

HARDWAPE: Spurious isolation of RHR suction valves. (See Sections 7.5.5 and 5.5.1(6).

$$HW = (PB405 + PT405 + K735) * T_M$$

$$HW1 = \overline{HW}|\text{Case B} = 1.03E-2$$

$$HW2 = \overline{HW}|\text{Case C} = 5.04E-4$$

DEPENDENCIES: Top event SA is guaranteed failed, given top events TV, DR, LM, VA, or IO failed, due to vortexing at low level. This dependency is modeled explicitly in the tree structure.

Top event SA also depends on whether the outage is a drained maintenance (Case B), with the level at the hot legs, or refueling (Case C), (Case C), with the level at the top of the vessel flange.

$$SA5 = \overline{SA}|\text{Case B}$$

$$SA6 = \overline{SA}|\text{Case C}$$

FAILURE SPLIT FRACTIONS:

$$SA5 = 3.2E-2$$

$$SA6 = 8.9E-4$$

5.5.2 (7) Top Event RM

SUCCESS: Decay heat removal is maintained by the preferred RHR train for the mission time.

FAILURE: The preferred train of RHR fails to operate for the mission time.

HUMAN: None.

HARDWARE: See RHR systems analysis. (Section 7.1).

DEPENDENCIES: RM4 = $\overline{RM}|$Case B (drained maintenance, T_M = 959 hr)

RM5 = $\overline{RM}|$Case C (refueling, T_M = 47 hr)

FAILURE SPLIT FRACTIONS:

RM4 = 3.7E-2

RM5 = 1.8E-3

5.5.3 Tree 3 - Refueling Cavity Fill

The description and quantification of split fractions in Tree 3 are as follows.

5.5.3 (1) Top Event DF

SUCCESS: Cavity drain valve SF-V-81 is closed prior to cavity filling.

FAILURE: SF-V-81 is left open as the cavity is being filled and operator fails to detect leakage.

HUMAN ERROR: Operator fails to close valve. (See Section 6.3).

$$OP_{DF} = 2.1E-5$$

HARDWARE: None

DEPENDENCIES: None

FAILURE SPLIT FRACTION:

$$DF1 = 2.1E-5$$

5.5.3 (2) Top Ev_nt CS

SUCCESS: Cavity seal is installed correctly and maintains integrity for the mission time (160 hours).

FAILURE: Cavity seal is not installed correctly and leaks water from refueling cavity to reactor cavity.

HUMAN ERROR: Cavity seal incorrectly installed and leak test not verified. (See Section 6.3).

$$OP_{CS} = 1.7E-4$$

HARDWARE: Cavity seal failure. Negligible.

DEPENDENCIES: None.

FAILURE SPLIT FRACTION:

$$CS1 = 1.7E-4$$

5.5.3 (3) Top Event SA

SUCCESS: Suction flow is maintained in operating RHR train for 160 hours.

FAILURE: RHR suction flow is lost via valve closure.

HUMAN ERROR: None.

HARDWARE: See Sections 7.5.5 and 5.5.1(6).

$$HW = (PT405 + PB405 + K735) * T_M$$

$$= 1.64E-3$$

DEPENDENCIES: None.

FAILURE SPLIT FRACTION:

$$SA7 = 1.64E-3$$

5.5.3 (4) Top Event RM

SUCCESS: Decay heat removal is maintained by the preferred RHR train for the mission time.

FAILURE: The preferred train of RHR fails to continue to operate for the mission time, 160 hours.

HUMAN ERROR: None.

HARDWARE: See RHR system analysis. (Section 7.1).

DEPENDENCIES: None.

FAILURE SPLIT FRACTION:

RM6 = 6.3E-3

5.5.4 Tree 4 - Refueling Cavity Drain

The description and quantification of split fractions for these trees are as follows.

5.5.4 (1) Top Event CD

SUCCESS: Operator closes cavity drain valve RH-V-33.

FAILURE: Cavity drain valve RH-V-33 is left open.

HUMAN ERROR: Operator fails to close valve. (See Section 6.3).

$$OP_{CD} = 3.1E-3$$

HARDWARE: None.

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

$$CD1 = 3.1E-3$$

5.5.4 (2) Top Event BR

SUCCESS: RHR train B is realigned as an operable RHR train.

FAILURE: RHR train B is not realigned for RHR cooling.

HUMAN ERROR: Operator fails to realign RHR train B discharge valve RH-V26. (See Section 6.3).

$$OP_{BR} = 1.3E-2$$

HARDWARE: None.

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

BR1 = 1.3E-2

5.5.4 (3) Top Event DM

SUCCESS: The RCS level is drained down to the mid-plane of the hot leg nozzle to perform drained maintenance after refueling.

FAILURE: The RCS level is drained down to 4" below the reactor vessel flange to perform non-drained maintenance after refueling.

HUMAN ERROR: None.

HARDWARE None.

DEPENDENCIES: Top event DM is dependent on the type of maintenance planned after refueling. It is assumed that half of this maintenance period is used on primary system maintenance (e.g., steam generator inspection) necessitating draining to the mid-plane of the hot leg nozzle. The other half of the period is assumed used on secondary side maintenance (e.g., turbine rotor inspections) during which the level is maintained near the vessel flange.

Top event DM is assumed "successful" during the time the RCS is drained to install and remove the steam generator nozzle dams. Assuming 24 hours for installing and removing, the fractional time drained is:

$$\frac{48\ \text{hr}}{1440\ \text{hr}} = 0.034$$

FAILURE SPLIT FRACTIONS:

DM1 = 0.034

5.5.4 (4) Top Event RF

SUCCESS: Operator reduces RHR flow rate to about 1000 GPM on the operating RHR train.

FAILURE: Operator fails to reduce the flow rate in the operating RHR train from 3000 gpm to 1000 gpm when RCS level is at mid-plane of the hot leg nozzle.

HUMAN ERROR: Operator fails to reduce flow in RHR train causing vortexing in the RHR suction line. (See Section 6.3).

$$OP_{RF} = 3.1E-3$$

HARDWARE None.

DEPENDENCIES: The operator must reduce flow only when the level in the RCS is drained for maintenance. This dependency is shown explicitly in the tree structure.

FAILURE SPLIT FRACTIONS:

RF1 = 3.1E-3

5.5.4 (5) TOP EVENT LM

SUCCESS: Operator maintains desired level.

FAILURE: Level is decreased below desired level (-7' below flange) for drained maintenance or (-4" below flange) for non-drained maintenance which causes the operating RHR pump to cavitate. This failure occurs via the operator failing to control level.

HUMAN ERROR: Operator fails to control level. (See Section 6.3).

$OP3_{LM}$ = 8.6E-4 given drained to hot legs (DM)

$OP4_{LM}$ = 3.1E-4 given drained to flange ($\overline{DM}$)

HARDWARE: None.

DEPENDENCIES: LM3 = $\overline{LM}|DM$ - level at -7' below flange.

LM4 = $\overline{LM}|\overline{DM}$ - level at -4" below flange.

FAILURE SPLIT FRACTIONS:

LM3 = $OP3_{LM}$ = 8.6E-4

LM4 = $OP4_{LM}$ = 3.1E-4

5.5.4 (6) Top Event SA

SUCCESS: Suction flow is maintained in the operating RHR pump for 1440 hours.

FAILURE: RHR suction flow is lost via valve closure or vortexing at the RHR suction nozzle.

HUMAN ERROR: Operator fails to maintain level for 1440 hours. Failure to do so results in a vortexing RHR pump failure (see Section 6.3).

$OP6_{SA} = \overline{SA}|DM = 3.3E-2$

$OP7_{SA} = \overline{SA}|\overline{DM} = 1.2E-2$

HARDWARE: See Sections 7.5.5 and 5.5.1(6).

$HW = (PT405 + PB405 + K735) * T_M$

$= 1.47E-2$

DEPENDENCIES: $SA8 = \overline{SA}|DM$

$SA9 = \overline{SA}|\overline{DM}$

FAILURE SPLIT FRACTIONS:

$SA8 = 4.8E-2$

$SA9 = 2.7E-2$

5.5.4 (7) Top Event RM

SUCCESS: Decay heat removal is maintained by the preferred RHR train for the mission time.

FAILURE: The pr. rred train of RHR fails to continue to operate 'or the mission time, 1440 hours.

HUMAN ERROR: None.

HARDWARE: See RHR system analysis. (Section 7.1).

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

RM7 = 5.6E-2

5.5.5 Tree 5 - RCS Fill

The description and quantification of split fractions is Tree 5 are as follows.

5.5.5 (1) Top Event TL

SUCCESS: The temporary level transmitter is verified to be operable and operating.

FAILURE: The temporary level transmitter is not aligned for operation and operator does not detect error during cross calibration with LI 9405 or the indicator fails during the RCS fill. Failure caused guaranteed overpressure due to overfill. Overpressurization is l[illegible] severe due to volume of air entrapped in the ste[illegible] generator U tubes.

HUMAN ERROR: See Above.

OP_{TL} = 1.3E-2

HARDWARE: None.

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

TL1 = 1.3E-2

5.5.5 (2) Top Event CT

SUCCESS: The RHR suction valves for both trains continue to be open and cross-train depowered (i.e., for Train A suction path, the B valve is depowered, etc.).

FAILURE: The RHR suction valves are opened but the motor starters are not depowered for both of the cross-train valves.

HUMAN ERROR: Operator fails to ensure that the cross-train alignment is in effect. (See Section 6.3).

HARDWARE: None.

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

CT2 = 7.4E-3

5.5.5 (3) Top Event LM

SUCCESS: Operator maintains pressurizer level at 45' ft for the mission time.

FAILURE: Pressurizer level is increased to the water solid condition, causing overpressure event with RHR relief valve challenge.

HUMAN ERROR: Operator fails to stop excess charging at pressurizer level = 45', given his indicator is operable (i.e., top event TL is successful). (See Section 6.3).

$OP5_{LM} = 2.2E-3$

$OP6_{LM} = 3.4E-3$

HARDWARE: Hardware failures are judged to be negligible because charging is at high rate already. Operator action is to shut off pump if flow control valve fails open.

DEPENDENCIES: $LM5 = \overline{LM}|$Case B (drained maintenance, $T_M = 101$ hr).

$= OP5_{LM}$

$LM6 = \overline{LM}|$Case C (refueling, $T_M = 193$ hr).

$= OP6_{LM}$

FAILURE SPLIT FRACTIONS:

LM5 = 2.2E-3

LM6 = 3.4E-3

5.5.5 (4) Top Event CC

SUCCESS: Operators cross-calibrate LI-462 to the tygon level indicator.

FAILURE: LI-462 is not calibrated correctly.

HUMAN ERROR: Operator does not cross calibrate LI-462. (See Section 6.3).

$$OP1_{CC} = 2.9E-2$$

HARDWARE: Hardware failure is assumed to be negligible. Operator will restore LI-462 if inoperable.

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

CC1 = 2.9E-2

5.5.5 (5) Top Event LT

SUCCESS: Operators restore LTOP circuitry to service by restoring wide range pressure transmitters PT-403 or 405 to service prior to going solid.

FAILURE: Operators fail to restore PT-403 and PT-405 to service or both pressure transmitters have failed and operator fails to detect failures or both PTs fail after being restored to service.

HUMAN ERROR: Technicians do not unisolate wide range pressure transmitters and operator fails to detect this condition - i.e., pressure transmitters failed (see Section 6.3).

$$OP4_{LT} = OP5_{LT} = 4.7E-3$$

HARDWARE: See Sections 7.5.5 and D.1.5.

PT-403 and PT-405 fail after being restored. The hardware failure frequency is the frequency of both transmitters failing independently plus frequency of common cause failure.

$$HW = (PT + PP + BS)_A \quad (PT + PP + BS)_B + PT * BETA$$

where:

PT = pressure transmitter fails for mission time T_M

= $7.6E-6 * T_M$

PP = pressure programmer fails high for time T_M

= $2.94E-6 * T_M$

BS = bistable fails low for time T_M

= $2.21E-6 * T_M$

BETA = beta factor common cause failure of pressure transmitters

= 0.125 (generic value)

Thus,

$$HW1 = \overline{HW}|\text{Case B } (T_M = 101 \text{ hr})$$

$$= 9.7\text{E-5}$$

$$HW2 = \overline{HW}|\text{Case C } (T_M = 193 \text{ hr})$$

$$= 1.89\text{E-4}$$

DEPENDENCIES:

$$LT4 = \overline{LT}|\text{Case B } (T_M = 101 \text{ hr})$$

$$LT5 = \overline{LT}|\text{Case C } (T_M = 193 \text{ hr})$$

The tree explicitly models the dependency between LT and CC, i.e., LT is guaranteed to fail when CC failed. This assumes operator failures are perfectly coupled because they are on the same check list performed by IC technicians.

Also, top event LT in Tree 5 is assumed to be independent of top event LT in Tree 1. This is because the LTOP circuitry is restored to service during RCS fill and evacuation and its previous status does not affect the restoration.

FAILURE SPLIT FRACTIONS:

$$LT4 = OP4_{LT} + HW1 = 4.8\text{E-3}$$

$$LT5 = OP5_{LT} + HW2 = 4.9\text{E-3}$$

5.5.5 (6) <u>Top Event PU</u>

SUCCESS: Operator increases pressure to 325 psig and maintains level for the mission time.

FAILURE: Charging in excess of letdown at P = 325 psig causing overpressure with RCS water solid.

HUMAN ERROR: (1) Operator fails to control charging while increasing RCS pressure. (See Section 6.3).

$$OP_{PU} = 3.9E-3$$

(2) hardware failures cause exces charging and operator fails to recover before an overpressure event. The hardware failures are assumed to be unrecoverable due to the potentially short time available.

HARDWARE: Hardware-induced excess charging can oc r in three general ways (as discussed in Section [illegible] .8 top event NC):

(1) inadvertent SI signal which isolates letdown,

(2) CS-PCV-131 fails closed causing iso tion of letdown,

(3) CS-FCV-121 fails open causing maximum charging, and

These hardware failures are quantified as follows:

(1) $ISI = F_{ISI} * NR = 1.0E-3$

where:

F_{ISI} = frequency of inadverte SI signals

= 1.0E-3

NR = 1.0 (no recovery assumed)

(2) CS-PCV-131 failing closed causing isolation of letdown:

$V131 = PT * T_M * NR_{131}$

where:

PT = frequency of pressure transmitter failure to operate

= 7.6E-6/hr (ZITRPR in Table 9-1)

T_M = mission time

= 101 hr for Case B

= 193 hr for Case C

NR = 1.0 (no recovery assumed)

Thus,

$V131(1) = V131|_{\text{Case B}} (T_M = 101 \text{ hr})$

= 7.68E-4

$V131(2) = V131|_{\text{Case C}} (T_M = 193 \text{ hr})$

= 1.47E-3

(3) CS-FCV-121 failing open causing maximum charging:

$V121 = (AOT + FT) * T_M * REC$

where:

AOT = frequency of air operated valve transfer open

= 2.67 E-7/hr (ZIVAOT in Table 9-1)

FT = frequency of flow transmitter to operate

= 6.25 E-6/hr (ZITRFR in Table 9-1)

T_M = 101 hr for Case B

= 193 hr for Case C

NR = 1.0 (no recovery assumed)

$V121(1) = V121|Case\ B = 6.59E-4$

$V121(2) = V121|Case\ C = 1.26E-3$

DEPENDENCIES: $PU1 = \overline{PU}|Case\ B$

$PU2 = \overline{PU}|Case\ C$

FAILURE SPLIT FRACTIONS:

$PU1 = OP_{PU} + HW1 = 6.3E-3$

$PU2 = OP_{PU} + HW2 = 7.6E-3$

5.5.5 (7) Top Event SA

SUCCESS: RHR suction flow is maintained in the operating RHR pump.

FAILURE: RHR suction flow is lost via valve closure or vortexing at the RHR suction nozzles.

HUMAN ERROR: None.

HARDWARE: See Sections 7.5.5 and 5.5.1(6).

DEPENDENCIES:

$SAA = \overline{SA}|LT * \text{Case B} \quad (T_M = 101 \text{ hr})$

$SAB = \overline{SA}|\overline{LT} * \text{Case B} \quad (T_M = 101 \text{ hr})$

$SAC = \overline{SA}|LT * \text{Case C} \quad (T_M = 193 \text{ hr})$

$SAD = \overline{SA}|\overline{LT} * \text{Case C} \quad (T_M = 193 \text{ hr})$

FAILURE SPLIT FRACTIONS:

SAA = 2.7E-4

SAB = 1.0E-3

SAC = 5.0E-4

SAD = 2.0E-3

5.5.5 (8) Top Event RM

SUCCESS: Decay heat removal is maintained by the preferred RHR train for the mission time.

FAILURE: The preferred train of RHR fails to continue to operate for the mission time, 101 hours for drained maintenance (Case B) and 193 hours for refueling (Case C).

HUMAN ERROR: None.

HARDWARE: See RHR systems analysis (Section 7.1).

DEPENDENCIES: RM8 = $\overline{RM}|$Case B (drained maintenance, T_M = 101 hr)

RM9 = $\overline{RM}|$Case C (refueling, T_M = 193 hr)

FAILURE SPLIT FRACTIONS:

RM8 = 3.9E-3

RM9 = 7.5E-3

5.5.6 Tree 6 - Cold Startup

The description and quantification of split fractions in Tree 6 are as follows.

5.5.6 (1) Top Event LI

SUCCESS: Operator controls inventory during heatup.

FAILURE: Operator fails to control inventory sufficiently to compensate for volumetric expansion during heatup, resulting in an overpressurization. This can occur due to an operator error or a hardware failure and failure of the operator to recover.

$$LI = OP_{LI} + HW_{LI} * NR$$

HUMAN ERROR: Operator does not increase letdown flow to match volumetric expansion. (See Section 6.3).

$$OP1_{LI} = \overline{OP}|\text{Case A,B} = 9.0E-4$$

$$OP2_{LI} = \overline{OP}|\text{Case C} = 2.3E-3$$

HARDWARE: Hardware-induced excess charging can occur in three general ways, as described in Top Event NC (Section D.1):

(1) inadvertent SI signal which isolates letdown and causes charging flow from one pump (ISI),

(2) CS-PCV-131 failing closed causing isolation of letdown (V131),

(3) CS-FCV-121 failing open causing maximum charging flow (V121), and

In Tree 6, the pressurizer is maintained with a bubble. Thus, the non-recovery fractions used in Tree 1 in Top Event NC for Case A are applied for all cases.

$$HW1_{LI} = \overline{HW}|\text{Case A,B } (T_M = 24 \text{ hr})$$

$$= ISI(1) + V131(1)_{24} + V121(1)_{24}$$

$$= 3.2E-4 + 2.0E-5 + 3.8E-5$$

$$= 3.8E-4$$

$$HW2_{LI} = \text{Case C } (T_M = 72 \text{ hr})$$

$$= ISI(1) + V131(1)_{72} + V12''(1)_{7}$$

$$= 3.2E\text{-}4 + 6.0E\text{-}5 + 1.1E\text{-}4$$

$$= 4.9E\text{-}4$$

DEPENDENCIES: $LI1 = \overline{LI}|\text{Case A,B}$

$LI2 = \overline{LI}|\text{Case C}$

FAILURE SPLIT FRACTIONS:

$$LI1 = OP1_{LT} + HW1_{LI} = 1.3E\text{-}3$$

$$LI2 = OP2_{LI} + HW2_{LT} = 2.8E\text{-}3$$

5.5.6 (2) Top Event LT

SUCCESS: At least one overpressure protection channel is available.

FAILURE: Both overpressure protection channels are inoperable.

HUMAN ERROR: None

HARDWARE: See Sections 7.5.5 and 5.5.1(5).

Pressure transmitters PT-403 and PT-405 or the associated pressure programmer or bistable fail to operate during the mission time. The hardware unavailability is as follows:

$$HW = (PT + PP + BS)_A * (PT + PP + BS)_B + PT * BETA$$

where:

PT = pressure transmitter fails for mission time T_M

= $7.6E-6 * T_M$

PP = pressure programmer fails high for time T_M

= $2.94E-6 * T_M$

BS = bistable fails low for time T_M

= $2.21E-6 * T_M$

BETA = beta factor common cause failure of pressure transmitters

= 0.125 (generic value)

Thus,

$HW1 = \overline{HW}|\text{Case A or B } (T_M = 24 \text{ hr})$

$= 2.29E-5$

$HW2 = \overline{HW}|\text{Case C } (T_M = 72 \text{ hr})$

$= 6.92E-5$

DEPENDENCIES: LT6, LT7, and LT8 depend quantitatively on LT from Trees 1 and 5. It is assumed, if LT fails earlier (in Trees 1 and 5), it is not recovered in Tree 6. Thus,

$$LT6 = \overline{LT}|\text{Case A}$$

$$= \overline{LT} \text{ (Tree 1)} + \overline{LT} \text{ (Tree 6)}$$

$$= LT1 + HW1$$

$$= 2.43E-4$$

$$LT7 = \overline{LT}|\text{Case B}$$

$$= \overline{LT} \text{ (Tree 1)} + \overline{LT} \text{ (Tree 5)} + \overline{LT} \text{ (Tree 6)}$$

$$= LT2 + LT4 + HW1$$

$$= 3.0E-2$$

$$LT8 = \overline{LT}|\text{Case C}$$

$$= \overline{LT} \text{ (Tree 1)} + \overline{LT} \text{ (Tree 5)} + \overline{LT} \text{ (Tree 6)}$$

$$= LT3 + LT5 + HW2$$

$$= 3.0E-2$$

FAILURE SPLIT FRACTIONS:

LT6 = 2.4E-4

LT7 = 3.0E-2

LT8 = 3.0E-2

5.5.6 (3) Top Event SA

SUCCESS: Suction flow is maintained in the operating RHR train.

FAILURE: RHR suction flow is lost via valve closure.

HUMAN ERROR: None.

HARDWARE: See Sections 7.7.5 and 5.5.1(6)

DEPENDENCIES:

$SAE = \overline{SA}|LT$ Case A,B (T_M = 24 hr)

$SAG = \overline{SA}|\overline{LT}$ Case A,B (T_M = 24 hr)

$SAH = \overline{SA}|LT$ Case C (T_M = 72 hr)

$SAI = \overline{SA}|\overline{LT}$ Case C (T_M = 72 hr)

FAILURE SPLIT FRACTIONS:

SAE = 6.3E-5

SAG = 2.5E-4

SAH = 1.9E-4

SAI = 7.3E-4

5.5.6 (4) <u>Top Event RM</u>

SUCCESS: Decay heat removal is maintained by the preferred RHR train for the mission time.

FAILURE: The preferred train of RHR fails to continue to operate for the mission time, 24 hours for non-drained maintenance (Case A) and 72 hours for drained maintenance on refueling (Cases B or C).

HUMAN ERROR: None.

HARDWARE: See RHR systems analysis (Section 7.1).

DEPENDENCIES: RMA = $\overline{RM}$|Case A or B (T_M = 24 hr)

RMB = $\overline{RM}$|Case C (T_M = 72 hr)

FAILURE SPLIT FRACTIONS:

RMA = 9.3E-4

RMB = 2.8E-3

5.5.6 (5) <u>Top Event CT</u>

SUCCESS: The RHR suction valves for both trains continue to be open and cross-train depowered.

FAILURE: The RHR suction valves are open but the motor starters are not depowered for both of the cross-train valves.

HUMAN ERROR: Operator fails to ensure that the cross-train alignment is in effect. It is assumed that the operator does not detect the cross-train misalignment in tree 6, if CT comes into tree 6 failed. It is also assumed that, if CT is properly aligned coming into tree 6, it is not misaligned in tree 6.

HARDWARE: None.

DEPENDENCIES: For Case A, event CT could have failed in tree 1. Thus,

$$CT1 = \overline{CT}|\text{Case A}$$

$$= \overline{CT} \text{ (Tree 1)}$$

$$= 1.7E-2$$

For Case B and C, event CT could have failed in tree 1 or failed due to test/maintenance and not been recovered in tree 5. Thus,

$$CT2 = \overline{CT}|\text{Case B,C}$$

$$= 7.4E-3$$

FAILURE SPLIT FRACTIONS:

CT1 = 1.7E-2

CT2 = 7.4E-3

5.5.6 (6) Top Event IS

SUCCESS: Operator isolates RHR from RCS when cold leg temperature > 329°F.

FAILURE: RHR is not isolated when RCS cold leg temperature > 329°F. This failure results in an overpressure challenge to RHR relief valves.

HUMAN ERROR: Operator does not follow RHR shutdown procedure and omits procedure steps of closing RHR suction isolation valves before racking out breakers. (See Section 6.0).

$$OP_{IS} = 3.1E-3$$

HARDWARE: None.

DEPENDENCIES: None.

FAILURE SPLIT FRACTIONS:

IS1 = 3.1E-3

5.6 Uncertainty Analysis

The uncertainty in the frequency of core damage was calculated by first estimating the uncertainties in the basic model parameters and then propagating the parameter uncertainties through a simplified model based on the dominate sequences. The distributions resulting from the uncertainty analysis are given in Table 5-14 for the total core damage frequency as well as core damage for various plant damage states. The parameter uncertainties were propagated through the dominant core damage sequences (determined from the point estimate model) using the STADIC4 computer code (Reference 23). The STADIC4 code combines all parameter uncertainties using a Monte Carlo simulation. The sources of uncertainty included are:

- estimated frequencies and durations of outages,
- time spent in execution of individual shutdown procedures and in various plant configurations,
- time of accident initiation, as measured from time at 100% power,
- frequency of initiating events (e.g., hardware failure of RHR pump, fire in the PAB), and
- failure frequency of operator actions and equipment in response to initiating events.

In general, uncertainties in these parameters were represented by log-normal distributions or discreet distributions as documented in Sections 6 (human), 7 (systems), 8 (external events), 9 (frequency/duration data), 10.1.7 (source terms) and Appendix F.3 (input distributions). The mean values of these distributions were used in the point-estimate calculation described in Sections 5.1 through 5.5. Thus, the point-estimate value for core melt and the mean value from the STADIC4 model are expected to, and do in fact, closely agree.

Figure 5-1 illustrates the model used to assess uncertainty in core damage frequency.

To assess the overall uncertainty in core damage frequency, the list of dominant core damage sequences from the point-estimate model was used to identify the sequences which represented a cumulative total of 90% of the complete core damage frequency. For each of these sequences, a model was constructed incorporati., sources of uncertainty as shown in Figure 5-1. Each of these sequence models was then quantified a large number of times (> 10,000) using the STADIC4 Monte Carlo sampling to create uncertainty distributions for the frequency of the individual core damage sequences and for the total core damage frequency. The FORTRAN "SAMPLE" subroutine code used to construct models for each core damage sequence is provided in Appendix F. The models for individual core damage sequences are shown in Code Block 7 in Appendix F.1.

The treatment of uncertainties shown in Box 1 and Box 2 of Figure 5-1, used to identify uncertainties in the timing of accident initiation, is discussed in detail in Section 10.1.7. This source of uncertainty is particularly important for shutdown events (as compared to power operation events) because it affects the time available for the operator to diagnose plant conditions and initiate appropriate actions. Section 5.6.1 describes the application of the uncertainty in accident initiation time to the analysis of uncertainty in the key operator actions which model operator failure to diagnose plant conditions and initiate appropriate action (Box 3).

The modeling of uncertainties in system failure frequencies (Box 4) is generally based on propagating component failure rate uncertainties and maintenance time uncertainties and in some cases operator failure rate uncertainties (e.g., starting an RHR pump) through the system logic models developed in Section 7 (see Appendix F, Code Block 6). Application of these results to the development of uncertainties in procedural and non-procedural (support system failures, internal or external hazards causing loss of RHR) initiating event frequencies (Boxes 5 and 6) is discussed in Section 5.6.2.

Electric power recovery is also dependent on the time available after a station blackout until core damage. The effect of the uncertainty in time available for offsite power or diesel generator recovery (Box 7) is modeled in STADIC4 as discussed in Section 5.6.3. The quantitative effect of the uncertainty analysis on the electric power system failure frequency is included in the point-estimate values in a sequence-by sequence analysis of recovery (see Section 2.5).

5.6.1 Uncertainty in Time for Operator Actions (OR, OL)

The event tree top events used to model operator action to diagnose plant conditions and initiate appropriate actions are event OR in the transient tree and event OL in the LOCA tree. The failure frequencies for these operator actions (see Section 6.2) were quantified based on a human reliability model adapted from the Handbook of Human Reliability Analysis (Reference 17). Figure 12-4 of the Handbook relates "time available for operator action after a compelling signal" to "probability of failure to diagnose" within that time.

To quantify the "probability of failure to diagnose" it was therefore necessary to develop a model for the time available for operator action. This time is dependent on when the accident was initiated (as measured from 100% power) and the RCS configuration (filled or drained to the vessel flange or hot leg) at the time of the accident. Section 10.1.7 describes in detail the model used to assess time of accident initiation. As described in Section 10.1.7, a unique uncertainty distribution is developed for the time of accident initiation (Box 1, Figure 5-1), given initiation of an accident during execution of a particular procedure during a particular outage type. Thus, for an event occurring in any procedure event tree (A1, A6, B1...), a distribution of the timing of that event (measured from time at 100% power) is generated. FORTRAN coding for development of these distributions is shown in Appendix F, Section F.3, Code Block 1.

Following initiation of an event in a particular procedure event tree, the "time available for operator action" is taken to be the time from accident initiation to the time of onset of severe core damage (fuel clad temperatures of 1200°F). This time is modeled by using empirical thermal-hydraulic formulas to calculate the time to occurrence of clad temperatures of 1200°F as a function of the time of accident initiation, and as a function of the RCS configuration at the time of accident initiation. Thermal-hydraulic modeling uncertainties are also included in this calculation. Using STADIC4 Monte Carlo sampling, an uncertainty distribution is then created for the "time available for operator action", given the occurrence of an accident in any procedure event tree. FORTRAN coding for the empirical thermal-hydraulic models is shown in the functions at the end of Appendix F, Sections F.1 and F.2.

In developing uncertainty models for core damage sequences, which include failure of event tree top events OR or OL, it was necessary to determine from which procedure event tree or trees the sequence was initiated and the fractional contribution from each procedure tree if initiation in more than one tree was possible. For procedure initiated events this information was provided from MAXIMA6 output For non-procedure initiated events, it was assumed that the fractional occurrences of the event in any procedure tree (A1, A6, B1, etc.) was equal to the fractional time spent in the tree. For each procedure tree in which the sequence could be initiated, the time available for the operator was then determined (as described above) and the "probability of operator failure to diagnose" was calculated using Figure 12-4 of Reference 17. Uncertainty in the values provided in Figure 12-4 was also modeled by assuming that the actual "probability of operator failure to diagnose" was uniformly distributed between the lower and upper bound curves shown in the figure. FORTRAN coding for the calculation of OR and OL values is shown in Appendix F, Section F.1, Code Block 5.

5.6.2 <u>Uncertainties in Initiating Event Frequencies</u>

Uncertainties in the frequency of non-procedural initiating events were assessed by propagating component failure rate uncertainties through the logic models used to develop initiating event frequencies. FORTRAN coding for development of non-procedure initiating event frequency distributions is shown in Appendix F, Code Block 3. For seismic initiating events frequencies, output from the computer program SEIS4 was used to provide an uncertainty distribution.

The development of uncertainties in the frequency of procedure-initiated events required consideration of uncertainties shown in Boxes 1 and 4 of Figure 5-1. For each procedure-initiated event occurring in the list of dominant core damage sequences considered in assessing total core damage frequency uncertainty, the following method was applied to assess uncertainty in the initiating event frequency.

First, the individual procedure event tree sequences contributing to the procedure-initiated event were identified from the MAXIMA6 procedure tree output. Second, uncertainty distributions were developed for each of the top events appearing in these procedure event tree sequences. In general, these events were component-related failures, for which pre-existing component failure rate uncertainties were used, or simple operator actions for which lognormal distributions were assumed. Third, for procedure-initiated events which were dependent on the length of time spent in a particular procedure event tree, the uncertainties in outage frequency and procedure tree duration (Box 1 in Figure 5-1) were incorporated in the creation of the initiating event frequency uncertainty distribution. FORTRAN coding for development of procedure-initiated event frequency distributions is shown in Appendix F, Section F.1, Code Block 4.

5.6.3 Uncertainty in Time for Electric Power Recovery (EPR)

The time available for recovery of electric power, given a station blackout (loss of offsite power and failure of both diesels) is also a function of the time available until core uncovery and cladding failure. The uncertainty in time available was modeled as in the operator actions OR and OL to account for the uncertainty in time after shutdown and RCS configuration.

The probabilities of non-recovery of offsite power and of diesel generators, as they vary with time, are taken from Section 10.4 of the SSPSA (Reference 1). The STADIC4 computer model calculates the conditional probability of failure of the onsite power system (diesel generators) and no recovery of onsite or offsite electric power during the first 24 hours after loss of offsite power initiating event. (PLG-0507, Reference 20).

The model considers the impact of station electric batteries, the RCS configuration (filled with secondary cooling, drained to the top of the flange, and drained to the hot leg midplane), and the recoverability of offsite power and are or both diesels. The time to core uncovery is the time to boil dry the steam generators (for the W configuration) and heatup and boil the RCS inventory above the top of the core.

The quantification of electric power recovery model is summarized in Table 7-7 (Section 7.2.4). Electric power recovery was applied to the point estimate model on a sequence-by-sequence basis, as described in Section 2.

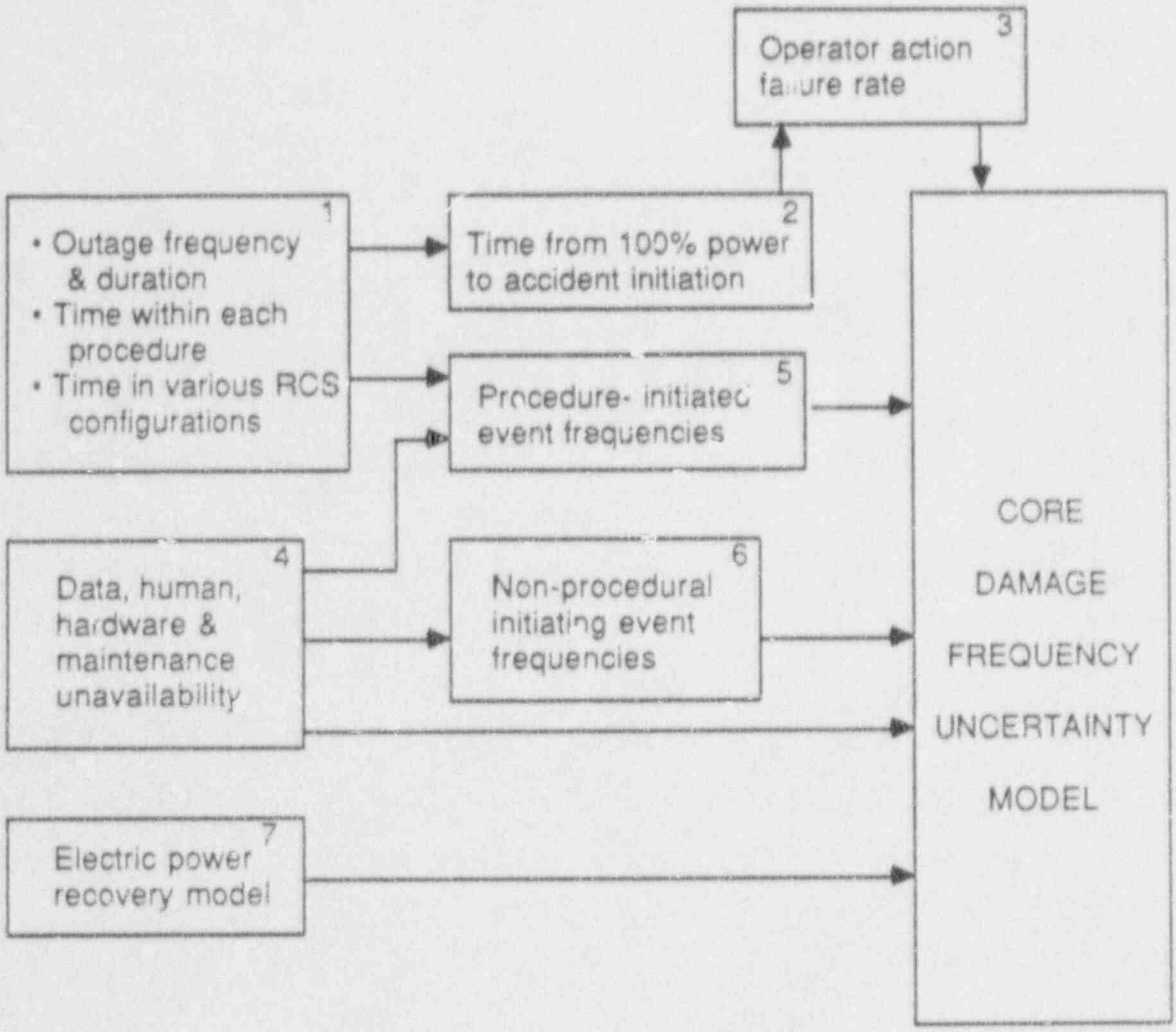


FIGURE 5-1

CORE DAMAGE FREQUENCY UNCERTAINTY MODEL

CORE DAMAGE POINT ESTIMATE RESULTS -
INITIATING EVENT CONTRIBUTION TO PLANT DAMAGE STATES

	R1D	R1P	R1N	R2D	R2P	R2N	R6D	R6P	R6N	TOTAL
LOSPI	0.00E+00	0.00E+00	0.00E+00	2.47E-06	1.03E-07	2.85E-10	0.00E+00	0.00E+00	0.00E+00	2.58E-06
LPCAI	0.00E+00	0.00E+00	0.00E+00	7.76E-07	3.23E-08	4.14E-09	0.00E+00	0.00E+00	0.00E+00	8.13E-07
LSWAI	0.00E+00	0.00E+00	0.00E+00	8.03E-08	3.34E-09	4.29E-10	0.00E+00	0.00E+00	0.00E+00	8.41E-08
LPCCI	0.00E+00	0.00E+00	0.00E+00	6.58E-09	2.74E-10	3.51E-11	0.00E+00	0.00E+00	0.00E+00	6.89E-09
LOSWI	0.00E+00	0.00E+00	0.00E+00	7.14E-10	2.97E-11	3.81E-12	0.00E+00	0.00E+00	0.00E+00	7.47E-10
FLSWI	0.00E+00	0.00E+00	0.00E+00	5.66E-09	2.36E-10	6.49E-13	0.00E+00	0.00E+00	0.00E+00	5.90E-09
TCTLI	0.00E+00	0.00E+00	0.00E+00	2.10E-08	8.73E-10	2.40E-12	0.00E+00	0.00E+00	0.00E+00	2.19E-08
FSGAI	0.00E+00	0.00E+00	0.00E+00	6.69E-07	2.79E-08	3.57E-09	0.00E+00	0.00E+00	0.00E+00	7.00E-07
FCRCI	0.00E+00	0.00E+00	0.00E+00	3.94E-08	1.64E-09	4.51E-12	0.00E+00	0.00E+00	0.00E+00	4.10E-08
FETGI	0.00E+00	0.00E+00	0.00E+00	1.43E-07	5.96E-09	7.64E-10	0.00E+00	0.00E+00	0.00E+00	1.50E-07
FETBI	0.00E+00	0.00E+00	0.00E+00	3.68E-08	1.54E-09	1.97E-10	0.00E+00	0.00E+00	0.00E+00	3.86E-08
FPCCI	0.00E+00	0.00E+00	0.00E+00	2.25E-08	9.39E-10	1.20E-10	0.00E+00	0.00E+00	0.00E+00	2.36E-08
FTLPI	0.00E+00	0.00E+00	0.00E+00	1.32E-07	5.49E-09	1.51E-11	0.00E+00	0.00E+00	0.00E+00	1.37E-07
FPABI	0.00E+00	0.00E+00	0.00E+00	3.57E-07	1.49E-08	1.91E-09	0.00E+00	0.00E+00	0.00E+00	3.74E-07
FLRRI	0.00E+00	0.00E+00	0.00E+00	6.12E-09	2.55E-10	3.27E-11	0.00E+00	0.00E+00	0.00E+00	6.41E-09
FL1GI	0.00E+00	0.00E+00	0.00E+00	1.19E-08	4.96E-10	1.36E-12	0.00E+00	0.00E+00	0.00E+00	1.24E-08
LS	0.00E+00	0.00E+00	0.00E+00	3.49E-06	1.45E-07	1.44E-07	0.00E+00	0.00E+00	0.00E+00	3.78E-06
LOSPW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.52E-07	2.64E-09	5.19E-09	1.60E-07
LPCAW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.15E-07	3.71E-09	7.67E-10	2.19E-07
LSWAW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.30E-08	3.97E-10	8.20E-11	2.34E-08
LPCCW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.30E-08	2.25E-10	4.66E-11	1.33E-08
LOSWW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.48E-10	2.55E-12	5.28E-13	1.51E-10
FLSWW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.28E-10	3.94E-12	7.90E-12	2.39E-10
TCTLW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.71E-09	4.68E-11	9.40E-11	2.85E-09
FSGAW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.70E-07	2.95E-09	6.09E-10	1.74E-07
FCRCW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.88E-08	1.20E-09	1.02E-09	3.10E-08
FETGW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.69E-10	1.68E-11	3.46E-12	9.89E-10
FETBW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.37E-10	4.09E-12	8.46E-13	2.42E-10
FPCCW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.69E-10	1.50E-11	3.10E-12	8.87E-10
FTLPW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.82E-08	3.15E-10	6.33E-10	1.92E-08
FPABW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.48E-08	2.55E-10	5.28E-11	1.51E-08
FLRRW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.37E-11	4.09E-13	8.46E-14	2.42E-11
FL1GW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.37E-09	2.37E-11	4.74E-11	1.44E-09
SSBOI	0.00E+00	0.00E+00	0.00E+00	1.06E-06	4.40E-08	1.21E-10	0.00E+00	0.00E+00	0.00E+00	1.10E-06
SSBOW	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.14E-06	8.90E-08	7.59E-08	2.30E-06
SLLW	0.00E+00	0.00E+00	0.00E+00	3.53E-07	1.47E-08	1.25E-08	0.00E+00	0.00E+00	0.00E+00	3.80E-07
X3N	0.00E+00	0.00E+00	0.00E+00	1.02E-05	4.24E-07	5.43E-08	0.00E+00	0.00E+00	0.00E+00	1.06E-05
X4N	0.00E+00	0.00E+00	0.00E+00	6.00E-07	2.50E-08	3.21E-09	0.00E+00	0.00E+00	0.00E+00	6.28E-07
X5N	0.00E+00	0.00E+00	0.00E+00	1.15E-05	4.80E-07	6.15E-08	0.00E+00	0.00E+00	0.00E+00	1.21E-05
X6N	0.00E+00	0.00E+00	0.00E+00	1.57E-06	6.54E-08	8.38E-09	0.00E+00	0.00E+00	0.00E+00	1.64E-06
T3N	0.00E+00	0.00E+00	0.00E+00	2.17E-08	3.76E-10	4.65E-11	0.00E+00	0.00E+00	0.00E+00	2.22E-08
T5N	0.00E+00	0.00E+00	0.00E+00	9.59E-08	1.66E-09	2.05E-10	0.00E+00	0.00E+00	0.00E+00	9.77E-08
W1A	0.00E+00	0.00E+00	0.00E+00	3.22E-06	1.35E-07	1.33E-07	4.25E-07	1.74E-08	1.70E-08	3.95E-06
W3A	0.00E+00	0.00E+00	0.00E+00	9.45E-10	3.96E-11	3.59E-11	5.62E-10	1.27E-11	6.28E-12	1.60E-09
W3B	0.00E+00	0.00E+00	0.00E+00	6.97E-10	3.53E-11	2.89E-11	4.15E-10	2.48E-11	5.24E-12	1.21E-09
W3C	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.03E-10	1.99E-11	0.00E+00	1.27E-09	5.03E-11	1.85E-09
W3N	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.69E-07	6.38E-09	1.09E-09	3.77E-07
W5A	0.00E+00	0.00E+00	0.00E+00	1.61E-08	6.75E-10	6.63E-10	9.59E-09	2.16E-10	1.07E-10	2.74E-08
W5B	0.00E+00	0.00E+00	0.00E+00	4.18E-12	2.12E-13	1.74E-13	2.49E-12	1.49E-13	3.14E-14	7.24E-12
W5C	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.40E-12	1.34E-13	0.00E+00	8.61E-12	3.40E-13	1.25E-11

TABLE 5-1

CORE DAMAGE POINT ESTIMATE RESULTS -
INITIATING EVENT CONTRIBUTION TO PLANT DAMAGE STATES

	R1D	R1P	R1N	R2D	R2P	R2N	R6D	R6P	R6N	TOTAL
W5N	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.06E-07	1.57E-05	2.69E-08	9.26E-07
W6A	0.00E+00	0.00E+00	0.00E+00	1.65E-07	6.29E-09	6.77E-09	9.25E-08	2.22E-09	1.09E-09	2.80E-07
W6B	0.00E+00	0.00E+00	0.00E+00	3.24E-13	1.64E-14	1.35E-14	1.94E-13	1.15E-14	2.44E-15	5.62E-13
W6C	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.50E-14	3.36E-15	0.00E+00	2.15E-13	8.50E-15	3.12E-13
W6N	0.00E+00	0.00E+00	0.00E+00	0.00E.00	0.00E+00	0.00E+00	3.38E-05	5.55E-10	1.00E-10	3.45E-05
L3	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.83E-09	1.45E-11	0.00E+00	7.88E-10	4.04E-12	3.64E-09
L5	5.40E-08	2.46E-09	2.90E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.65E-08
L6	0.00E+00	0.00E+00	0.00E+00	6.56E-09	2.99E-10	3.52E-11	0.00E+00	0.00E+00	0.00E+00	6.90E-09
TOTAL	5.40E-08	2.46E-09	2.90E-10	3.71E-05	1.55E-06	4.36E-07	4.62E-08	1.45E-07	1.07E-07	4.40E-05

TABLE 5-2

INITIATING EVENT IMPACTS ON SUPPORT TREE SYSTEMS

Initiating Event (a)	Support Systems						Possible Support States
	GA	GB	WA	WB	PA	PB	
1. LOSP1							O FA FB FAB
2. LPCCA	n	n			F		FA FAB
3. LSWA	n	n	F		*		FA FAB
4. LPCC	n	n			F	F	FAB
5. LOSW	n	n	F	F	*	*	FAB
6. FLSW			F	F	*	*	FAB
7. TCTL							O FA FB FAB
8. FSGA	n	n	F		*		FA FAB
9. FCRAC	F	F	*	*	*	*	FAB
10. FETG	n	n	F		F		FA FAB
11. FETB	n	n		F		*	FB FAB
12. FPCC	n	n			F	*	FAB
13. FTBLP							O FA FB FAB
14. FPAB	n	n	F	F	*	*	FAB
15. FLRHR	n	n					O FA FB FAB
16. FLISG	F		*		*		FA FAB
17. All Procedure-Initiated Events	n	n					O FA FB FAB

F = System train fails as direct impact of initiating event

* = System train fails due to failure of supporting system

n = System not asked since no LOSP occurs from initiating event

(a) = The initiating event impact on support systems shown on this table is not dependent on the RCS condition (X or W). Quantification of support systems shown on Table 5-2 does depend on RCS Condition because Technical Specifications require two trains of RHR (and, thus, support systems) if the RCS is drained (i.e., RCS Condition X). Planned maintenance can occur only when the RCS is full (i.e., RCS condition W).

TABLE 5-3a

SPLIT FRACTIONS USED TO QUANTIFY SUPPORT SYSTEM TREE AND PLANT RESPONSE TREES (GIVEN RCS CONDITION X - DRAINED)

Initiating Event	Support System Tree Top Events						Possible Support States	Simplified Transient Tree Top Events				
	GA	GB	WA	WB	PA	PB		OR	RR	LC	EH	SP
1. LOSP(X)	GA2	GBC	WA4	WBH	PA4	PB4	FO	ORS	RR6X	LC1	EH4	SP2
	PBI if $\overline{PA}$						FA	OR2	RR7X	LC2	EH4	SP2
	PB4 if $\overline{WA}$ or $\overline{GA}$											
	WBI if $\overline{WA}$						FB	ORS	RR8	LC3	EH4	SP2
	WB4 if $\overline{GA}$											
	GBD if $\overline{GA}$						FAB	OR5	RRF	LC4	EH4	SP2
2. LPCSA(X)	(b)	(b)	WA2	WBC	PAF	PB2	FA	OR2	RR7X	LC2	EH2	SP2
	WBD if $\overline{WA}$						FAB	OR5	RRF	LC4	EH2	SP2
3. LSWA(X)	(b)	(b)	WAF	WB2	(c)	PB2	FA	OR2	RR7X	LC2	EH2	SP2
							FAB	OR5	RRF	LC4	EH2	SP2
4. LPCC(X)	(b)	(b)	WA2	WBC	PAF	PBF	FAB	OR5	RRF	LC4	EH2	SP2
	WBD if $\overline{WA}$											
5. LOSW(X)	(b)	(b)	WAF	WBF	(c)	(c)	FAB	OR5	RRF	LC4	EH2	SP2
6. FLSW(X)	(c)	(c)	WAF	WBF	(c)	(c)	FAB	OR5	RRF	LC4	EH4	SP2
7. TCTL(X)	GA2	GBC	WA4	WBH	PA4	PBH	FO	ORS	RR6X	LC1	EH4	SP2
	PBI if $\overline{PA}$						FA	OR2	RR7X	LC2	EH4	SP2
	PB4 if $\overline{WA}$ or $\overline{GA}$											
	WBI if $\overline{WA}$						FB	ORS	RR8	LC3	EH4	SP2
	WB4 if $\overline{GA}$											
	GBD if $\overline{GA}$						FAB	OR5	RRF	LC4	EH4	SP2
8. FSGA(X)	(b)	(b)	WAF	WB2	(c)	PB2	FA	OR2	RR7X	LC2	EH2	SP2
							FAB	OR5	RRF	LC4	EH2	SP2
9. FCRAC(X)	GAF	GBF	(d)	(d)	(d)	(d)	FAB	ORF	(e)	(e)	EH4	SP2
10. FETG(X)	(b)	(b)	WAF	WB2	PAF	PB2	FA	OR5	RRF	LC2	EH2	SP2
							FAB	OR5	RRF	LC4	EH2	SP2

TABLE 5-3a

SPLIT FRACTIONS USED TO QUANTIFY SUPPORT SYSTEM TREE AND PLANT RESPONSE TREES (GIVEN RCS CONDITION X - DRAINED)

Initiating Event	Support System Tree Top Events						Possible Support States	Simplified Transient Tree Top Events				
	GA	GB	WA	WB	PA	PB		OR	RR	LC	EH	SP
11. FETB(X)	(b)	(b)	WA2	WBF	PA2	(c)	FB	OR4	RRF	LC3	EH2	SP2
							FAB	OR5	RRF	LC4	EH2	SP2
12. FPCC(X)	(b)	(b)	WA2	WBC	PAF	PBF	FAB	OR5	RRF	LC4	EH2	SP2
	WBD if $\overline{WA}$											
13. FTBLP(X)	GA2	GBC	WA4	WBH	PA4	PBH	FO	ORS	RR6X	LC1	EH4	SP2
	PBI if $\overline{PA}$						FA	OR2	RR7X	LC2	EH4	SP2
	PB4 if $\overline{WA}$ or $\overline{GA}$											
	WBI if $\overline{WA}$						FB	ORS	RR8	LC3	EH4	SP2
	WB4 if $\overline{GA}$											
	GBD if $\overline{GA}$						FAB	OR5	RRF	LC4	EH4	SP2
14. FPAB(X)	(b)	(b)	WAF	WBF	(c)	(c)	FAB	OR5	RRF	LC4	EH2	SP2
15. FLRHR(X)	(b)	(b)	WA2	WBC	PA2	PBC	FO	OR5	RRF	LC1	EH2	SP2
	PBD if $\overline{PA}$						FA	OR5	RRF	LC2	EH2	SP2
	PB2 if $\overline{WA}$											
	WBD if $\overline{WA}$						FB	OR5	RRF	LC3	EH2	SP2
							FAB	OR5	RRF	LC4	EH2	SP2
16. FLISG(X)	GAF	GB2	(d)	WB4	(d)	PB4	FA	OR2	RR7X	LC2	EH4	SP2
							FAB	OR5	RRF	LC4	EH4	SP2
17. X3N, X4N, X5N, X6N	(b)	(b)	WA2	WBC	PA2	PBC	FO	(See Table 5-4a)				
	PBD if $\overline{PA}$						FA					
	PB2 if $\overline{WA}$											
	WBD if $\overline{WA}$						FB					
							FAB					

TABLE 5-3a

SPLIT FRACTIONS USED TO QUANTIFY SUPPORT SYSTEM TREE AND PLANT RESPONSE TREES (GIVEN RCS CONDITION X - DRAINED)

(a) OR failure guarantees failure of RR and LC - top events not asked.

(b) Offsite power assumed available - top events not asked.

(c) Service Water failure guarantees PCC failure or Diesel Generator failure with LOSP - top events not asked.

(d) Loss of offsite power and emergency diesel guarantees failure of Service Water and PCC - top events not asked.

TABLE 5-3b

SPLIT FRACTIONS USED TO QUANTIFY SUPPORT SYSTEM TREE AND PLANT RESPONSE TREES (GIVEN RCS CONDITION W - FILLED)

Initiating Event	Support System Tree Top Events						Possible Support States	Simplified Transient Tree Top Events				
	GA	GB	WA	WB	PA	PB		OR	RR	LC	EH	SP
1. LOSP(W)	GA1	GBA	WA3	WBE	PA3	PBE	FO	OR5	RR6W	LC5	EH6	SP1
	PBG if $\overline{PA}$						FA	OR1	RR7W	LC6	EH6	SP1
	PB3 if $\overline{WA}$ or $\overline{GA}$											
	WBG if $\overline{WA}$						FB	OR5	RR8	LC7	EH6	SP1
	WB3 if $\overline{GA}$											
	GBB if $\overline{GA}$						FAB	OR1	RRF	LC8	EH6	SP1
2. LPCCA(W)	(b)	(b)	WA1	WBA	PAF	PB1	FA	OR1	RR7W	LC6	EH7	SP1
	WBB if $\overline{WA}$						FAB	OR1	RRF	LC8	EH7	SP1
3. LSWA(W)	(b)	(b)	WAF	WB1	(c)	PB1	FA	OR1	RR7W	LC6	EH7	SP1
							FAB	OR1	RRF	LC8	EH7	SP1
4. LPCC(W)	(b)	(b)	WA1	WBA	PAF	PBF	FAB	OR1	RRF	LC8	EH7	SP1
	WBB if $\overline{WA}$											
5. LOSW(W)	(b)	(b)	WAF	WBF	(c)	(c)	FAB	OR1	RRF	LC8	EH7	SP1
6. FLSW(W)	(c)	(c)	WAF	WBF	(c)	(c)	FAB	OR1	RRF	LC8	EH6	SP1
7. TCTL(W)	GA1	GBA	WA3	WBE	PA3	PBE	FO	OR5	RR6W	LC5	EH6	SP1
	PBG if $\overline{PA}$						FA	OR1	RR7W	LC6	EH6	SP1
	PB3 if $\overline{WA}$ or $\overline{GA}$											
	WBG if $\overline{WA}$						FB	OR5	RR8	LC7	EH6	SP1
	WB3 if $\overline{GA}$											
	GBB if $\overline{GA}$						FAB	OR1	RRF	LC8	EH6	SP1
8. FSGA(W)	(b)	(b)	WAF	WB1	(c)	PB1	FA	OR1	RR7W	LC6	EH7	SP1
							FAB	OR5	RRF	LC8	EH7	SP1
9. FCRAC(W)	GAF	GBF	(d)	(d)	(d)	(d	FAB	ORF	(a)	(a)	EH4	SP1
10. FETG(W)	(b)	(b)	WAF	WB1	PAF	PB1	FA	OR1	RRF	LC6	EH7	SP1
							FAB	OR1	RRF	LC8	EH7	SP1

TABLE 5-3b

SPLIT FRACTIONS USED TO QUANTIFY SUPPORT SYSTEM TREE AND PLANT RESPONSE TREES (GIVEN RCS CONDITION W - FILLED)

Initiating Event	Support System Tree Top Events						Possible Support States	Simplified Transient Tree Top Events				
	GA	GB	WA	WB	PA	PB		OR	RR	LC	EH	SP
11. FETB(W)	(b)	(b)	WA1	WBF	PA1	(c)	FB	OR1	RRF	LC7	EH7	SP1
							FAB	OR1	RRF	LC8	EH7	SP1
12. FPCC(W)	(b)	(b)	WA1	WBA	PAF	PBF	FAB	OR1	RRF	LC8	EH7	SP1
	WBB if $\overline{WA}$											
13. FTBLP(W)	GA1	GBA	WA3	WBE	PA3	PBE	FO	ORS	RR6w	LC5	EH6	SP1
	PBG if $\overline{PA}$						FA	OR1	RR7W	LC6	EH6	SP1
	PB3 if $\overline{WA}$ or $\overline{GA}$											
	WBG if $\overline{WA}$						FB	ORS	RR8	LC7	EH6	SP1
	WB3 if $\overline{GA}$											
	GBB if $\overline{GA}$						FAB	OR1	RRF	LC8	EH6	SP1
14. FPAB(W)	(b)	(b)	WAF	WBF	(c)	(c)	FAB	OR1	RRF	LC8	EH7	SP1
15. FLRHR(W)	(b)	(b)	WA1	WBA	PA1	PBA	FO	OR1	RRF	LC5	EH7	SP1
	PBB if $\overline{PA}$						FA	OR1	RRF	LC6	EH7	SP1
	PB1 if $\overline{WA}$											
	WBB if $\overline{WA}$						FB	OR1	RRF	LC7	EH7	SP1
							FAB	OR1	RRF	LC8	EH7	SP1
16. FL1SG(W)	GAF	GB1	(d)	WB3	(d)	PB3	FA	OR1	RR7W	LC6	EH6	SP1
							FAB	OR1	RRF	LC8	EH6	SP1
17. W1A, W3A/B/C/N, W5A/B.C/N, W6A/B/C/N, Y3N, Y5N, L1,LP,L3, L5,L6,LS	(b)	(b)	WA1	WBA	PA1	PBA	FO	Transients: (See Table 5-4b) LOCAs: (See Table 5-5)				
	PBB if $\overline{PA}$						FA					
	PB1 if $\overline{WA}$											
	WBB if $\overline{WA}$						FB					
							FAB					

TABLE 5-3b

SPLIT FRACTIONS USED TO QUANTIFY SUPPORT SYSTEM TREE AND PLANT RESPONSE TREES (GIVEN RCS CONDITION X - DRAINED)

(a) OR failure guarantees failure of RR and LC - top events not asked.

(b) Offsite power assumed available - top events not asked.

(c) Service Water failure guarantees PCC failure or Diesel Generator failure with LOSP - top events not asked.

(d) Loss of offsite power and emergency diesel guarantees failure of Service Water and PCC - top events not asked.

TABLE 5-4

SPLIT FRACTIONS USED TO QUANTIFY TRANSIENT TREE FOR PROCEDURE-INITIATED EVENTS

PROCEDURE INITIATED EVENT	APPLICABLE AUX. TREE RUN	POSSIBLE SUPPORT STATES	PC	VO	OC	SA	TP	OR	RR	LC	EN	SP	CONDITIONAL SPLIT FRACTIONS
W1A	18	0	PCF	VO1	OC1	SAS	TP2	OR5	RR1	LC5	EN1	SP1	
		FA	PCF	VO1	OC1	SAS	TP2	OR1	RR3	LC6	EN1	SP1	
		FB	PCF	VO1	OC1	SAS	TP2	OR5	RR5	LC7	EN1	SP1	
		FAB	PCF	VO1	OC1	SAS	TP2	OR1	RRF	LC8	EN1	SP1	
W3A	18	0	PCF	VO1	OC1	SAF	TP2	OR1	RR9	LC5	EN1	SP1	RR3 : $\overline{TP}$
		FA	PCF	VO1	OC1	SAF	TP2	OR1	RR3	LC6	EN1	SP1	
		FB	PCF	VO1	OC1	SAF	TP2	OR1	RR8	LC7	EN1	SP1	RRF : $\overline{TP}$
		FAB	PCF	VO1	OC1	SAF	TP2	OR1	RRF	LC8	EN1	SP1	
W3B	18	0	PCF	VO2	OC1	SAF	TP2	OR1	RR9	LC5	EN1	SP1	RR3 : $\overline{TP}$
		FA	PCF	VO2	OC1	SAF	TP2	OR1	RR3	LC6	EN1	SP1	
		FB	PCF	VO2	OC1	SAF	TP2	OR1	RR8	LC7	EN1	SP1	RRF : $\overline{TP}$
		FAB	PCF	VO2	OC1	SAF	TP2	OR1	RRF	LC8	EN1	SP1	
W3C	18	0	PCF	VOF	OC1	SAF	TP2	OR1	RR9	LC5	EN1	SP1	RR3 : $\overline{TP}$
		FA	PCF	VOF	OC1	SAF	TP2	OR1	RR3	LC6	EN1	SP1	
		FB	PCF	VOF	OC1	SAF	TP2	OR1	RR8	LC7	EN1	SP1	RRF : $\overline{TP}$
		FAB	PCF	VOF	OC1	SAF	TP2	OR1	RRF	LC8	EN1	SP1	

TABLE 5-4

SPLIT FRACTIONS USED TO QUANTIFY TRANSIENT TREE FOR PROCEDURE-INITIATED EVENTS

PROCEDURE INITIATED EVENT	APPLICABLE AUX TREE RUN	POSSIBLE SUPPORT STATES	PC	VO	OC	SA	TP	OR	RR	LC	EH	SP	CONDITIONAL SPLIT FRACTIONS
W3N	18	0	PCS	VOF	OC1	SAF	TP1	OR1	RR9	LC5	EH1	SP1	RR3 : $\overline{TP}$
		FA	PCS	VOF	OC1	SAF	TP1	OR1	RR3	LC6	EH1	SP1	
		FB	PCS	VOF	OC1	SAF	TP1	OR1	RR8	LC7	EH1	SP1	RRF : $\overline{TP}$
		FAB	PCS	VOF	OC1	SAF	TP1	OR1	RRF	LC6	EH1	SP1	
X3N	19	0	PCS	VOF	OC1	SAF	TP1	OR3	RRA	LC1	EH2	SP2	OR2 : $\overline{TP}$ RR4 : $\overline{TP}$
		FA	PCS	VOF	OC1	SAF	TP1	OR3	RR4	LC2	EH2	SP2	OR2 : $\overline{TP}$
		FB	PCS	VOF	OC1	SAF	TP1	OR3	RR8	LC3	EH2	SP2	OR4 : $\overline{TP}$ RRF : $\overline{TP}$
		FAB	PCS	VOF	OC1	SAF	TP1	OR5	RRF	LC4	EH2	SP2	
T3N	18	0	PCS	VOF	OC1	SAF	TP1	OR1	RR9	LC9	EH3	SP1	RR3 : $\overline{TP}$
		FA	PCS	VOF	OC1	SAF	TP1	OR1	RR3	LC9	EH3	SP1	
		FB	PCS	VOF	OC1	SAF	TP1	OR1	RR8	LC9	EH3	SP1	RRF : $\overline{TP}$
		FAB	PCS	VOF	OC1	SAF	TP1	OR1	RRF	LC9	EH3	SP1	
X4N	19	0	PCS	VOF	OC1	SAF	TP1	OR3	RR8	LC1	EH2	SP2	OR4 : $\overline{TP}$ RRF : $\overline{TP}$
		FA	PCS	VOF	OC1	SAF	TP1	OR4	RRF	LC2	EH2	SP2	
		FB	PCS	VOF	OC1	SAF	TP1	OR3	RR8	LC3	EH2	SP2	OR4 : $\overline{TP}$ RRF : $\overline{TP}$
		FAB	PCS	VOF	OC1	SAF	TP1	OR5	RRF	LC4	EH2	SP2	
W5A	18	0	PCF	VO1	OC1	SAS	TP2	OR1	RR3	LC5	EH1	SP1	
		FA	PCF	VO1	OC1	SAS	TP2	OR1	RR3	LC6	EH1	SP1	
		FB	PCF	VO1	OC1	SAS	TP2	OR1	RRF	LC7	EH1	SP1	
		FAB	PCF	VO1	OC1	SAS	TP2	OR1	RRF	LC5	EH1	SP1	

TABLE 5-4

SPLIT FRACTIONS USED TO QUANTIFY TRANSIENT TREE FOR PROCEDURE-INITIATED EVENTS

PROCEDURE INITIATED EVENT	APPLICABLE AUX. TREE RUN	POSSIBLE SUPPORT STATES	TRANSIENT TREE TOP EVENTS PC	VO	OC	SA	TP	OR	RR	LC	EH	SP	CONDITIONAL SPLIT FRACTIONS
W5B	18	0	PCF	VO2	OC1	SAS	TP2	OR1	RR3	LC5	EH1	SP1	
		FA	PCF	VO2	OC1	SAS	TP2	OR1	RR3	LC6	EH1	SP1	
		FB	PCF	VO2	OC1	SAS	TP2	OR1	RRF	LC7	EH1	SP1	
		FAB	PCF	VO2	OC1	SAS	TP2	OR1	RRF	LC8	EH1	SP1	
W5C	18	0	PCF	VOF	OC1	SAS	TP2	OR1	RR3	LC5	EH1	SP1	
		FA	PCF	VOF	OC1	SAS	TP2	OR1	RR3	LC6	EH1	SP1	
		FB	PCF	VOF	OC1	SAS	TP2	OR1	RRF	LC7	EH1	SP1	
		FAB	PCF	VOF	OC1	SAS	TP2	OR1	RRF	LC8	EH1	SP1	
W5N	18	0	PCS	VOF	OC1	SAS	TP1	OR1	RR3	LC5	EH1	SP1	
		FA	PCS	VOF	OC1	SAS	TP1	OR1	RR3	LC6	EH1	SP1	
		FB	PCS	VOF	OC1	SAS	TP1	OR1	RRF	LC7	EH1	SP1	
		FAB	PCS	VOF	OC1	SAS	TP1	OR1	RRF	LC8	EH1	SP1	
X5N	19	0	PCS	VOF	OC1	SAS	TP1	OR2	RR4	LC1	EH2	SP2	
		FA	PCS	VOF	OC1	SAS	TP1	OR3	RR4	LC2	EH2	SP2	
		FB	PCS	VOF	OC1	SAS	TP1	OR4	RRF	LC3	EH2	SP2	
		FAB	PCS	VOF	OC1	SAS	TP1	OR5	RRF	LC4	EH2	SP2	
Y5N	18	0	PCS	VOF	OC1	SAS	TP1	OR1	RR3	LC9	EH3	SP1	
		FA	PCS	VOF	OC1	SAS	TP1	OR1	RR3	LC9	EH3	SP1	
		FB	PCS	VOF	OC1	SAS	TP1	OR1	RRF	LC9	EH3	SP1	
		FAB	PCS	VOF	OC1	SAS	TP1	OR1	RRF	LC9	EH3	SP1	

TABLE 5-4

SPLIT FRACTIONS USED TO QUANTIFY TRANSIENT TREE FOR PROCEDURE-INITIATED EVENTS

PROCEDURE INITIATED EVENT	APPLICABLE AUX TREE RUN	POSSIBLE SUPPORT STATES	PC	VO	OC	SA	TP	OR	RR	LC	EH	SP	CONDITIONAL SPLIT FRACTIONS
W6A	18	0	PCF	VO1	OC1	SAS	TP2	OR1	RRF	LC5	EH1	SP1	
		FA	PCF	VO1	OC1	SAS	TP2	OR1	RRF	LC6	EH1	SP1	
		FB	PCF	VO1	OC1	SAS	TP2	OR1	RRF	LC7	EH1	SP1	
		FAB	PCF	VO1	OC1	SAS	TP2	OR1	RRF	LC8	EH1	SP1	
W6B	18	0	PCF	VO2	OC1	SAS	TP2	OR1	RRF	LC5	EH1	SP1	
		FA	PCF	VO2	OC1	SAS	TP2	OR1	RRF	LC6	EH1	SP1	
		FB	PCF	VO2	OC1	SAS	TP2	OR1	RRF	LC7	EH1	SP1	
		FAB	PCF	VO2	OC1	SAS	TP2	OR1	RRF	LC8	EH1	SP1	
W6C	18	0	PCF	VOF	OC1	SAS	TP2	OR1	RRF	LC5	EH1	SP1	
		FA	PCF	VOF	OC1	SAS	TP2	OR1	RRF	LC6	EH1	SP1	
		FB	PCF	VOF	OC1	SAS	TP2	OR1	RRF	LC7	EH1	SP1	
		FAB	PCF	VOF	OC1	SAS	TP2	OR1	RRF	LC8	EH1	SP1	
W6N	18	0	PCS	VOF	OC1	SAS	TP1	OR1	RRF	LC5	EH1	SP1	
		FA	PCS	VOF	OC1	SAS	TP1	OR1	RRF	LC6	EH1	SP1	
		FB	PCS	VOF	OC1	SAS	TP1	OR1	RRF	LC7	EH1	SP1	
		FAB	PCS	VOF	OC1	SAS	TP1	OR1	RRF	LC8	EH1	SP1	
X6N	19	0	PCS	VOF	OC1	SAS	TP1	OR4	RRF	LC1	EH2	SP2	
		FA	PCS	VOF	OC1	SAS	TP1	OR4	RRF	LC2	EH2	SP2	
		FB	PCS	VOF	OC1	SAS	TP1	OR4	RRF	LC3	EH2	SP2	
		FAB	PCS	VOF	OC1	SAS	TP1	OR5	RRF	LC4	EH2	SP2	

TABLE 5-5

SPLIT FRACTIONS USED TO QUANTIFY LOCA TREE FOR LOCA INITIATORS

PROCEDURE INITIATED EVENT	APPLICABLE AUX. TREE RUN	POSSIBLE SUPPORT STATES	OD	IR	MU	TP	OL	RR	LC	EH	SP	CONDITIONAL SPLIT FRACTIONS
LL-ST	19	0	OD1	IR1	MU1	TPA	OL1	RR3	LC5	EH5	SP2	Notes (1), (2), (3), (4)
	19	FA	OD1	IR1	MUF	TPA	OL1	RR3	LC6	EH5	SP2	Notes (1a), (2), (3), (4)
	19	FB	OD1	IR1	MU1	TPA	OL1	RRF	LC7	EH5	SP2	Notes (1), (2), LCF : $\overline{IR}$
	19	FAB	OD1	IR1	MUF	TPA	OL1	RRF	LCF	EH5	SP2	TPB : $\overline{IR}$, OLF : $\overline{OD}$, OLF : $\overline{IR}$
LP-ST	18	0	OD3	IR1	MU1	TPA	OL1	RR3	LC5	EH5	SPF	Notes (1), (2), (3), (5)
	18	FA	OD3	IR1	MUF	TPA	OL1	RR3	LC6	EH5	SPF	Notes (1a), (2), (3), (6)
	15	FB	OD3	IR1	MUF	TPA	OL1	RR3	LC4	EH5	SPF	Notes (1), (2), (7)
	18	FAB	OD3	IR1	MU1	TPA	OL1	RRF	LC7	EH5	SPF	TPS : $\overline{IR}$, OL6 : $\overline{OD}$, OLF : $\overline{IR}$

Conditional Split Fractions :

Note (1):

TPS : $\overline{IR}$ MU

TPB : $\overline{IR}$ $\overline{MU}$

Note (2):

OL6 : $\overline{IR}$

OL7 : $\overline{OD}$ IR

Note (3):

RRF : $\overline{IR}$

Note (4):

LCA : $\overline{IR}$ MU

LCB : $\overline{IR}$ $\overline{MU}$

Note (1a):

TPB : $\overline{IR}$ $\overline{MU}$

Note (5):

LC1 : $\overline{IR}$ MU

LCF : $\overline{IR}$ $\overline{MU}$

OL6 : $\overline{OD}$

Note (6):

LC2 : $\overline{IR}$ MU

LCF : $\overline{IR}$ $\overline{MU}$

Note (7):

LC3 : $\overline{IR}$ MU

LCF : $\overline{IR}$ $\overline{MU}$

TABLE 5-5

SPLIT FRACTIONS USED TO QUANTIFY LOCA TREE FOR LOCA INITIATORS

PROCEDURE INITIATED EVENT	APPLICABLE AUX TREE RUN	POSSIBLE SUPPORT STATES	OD	IR	MU	TP	OL	RR	LC	EH	SP	CONDITIONAL SPLIT FRACTIONS
			LOCA TREE TOP EVENTS									
L3(4)	19	0	OD2	IR2	MUF	TPS	OL4	RRF	LCF	EH2	SPF	Note (1)
	19	FA	OD2	IR2	MUF	TPS	OL4	RRF	LC6	EH2	SPF	Note (1)
	19	FB	OD2	IR2	MUF	TPS	OL4	RRF	LC7	EH2	SPF	Note (1)
	19	FAB	OD2	IR2	MUF	TPS	OL4	RRF	LCF	EH2	SPF	$OLF \mid \overline{IR}$ $OLF \mid \overline{OD}$
L5(3) & L6(3)	18	0	OD1	IRS	MUS	TPS	OL2	RR1	LC1	EH2	SP2	$OL7 \mid \overline{OD}$
	18	FA	OD1	IRS	MUS	TPS	OL2	RR3	LC2	EH2	SP2	$OL7 \mid \overline{OD}$
	18	FB	OD1	IRS	MUS	TPS	OL2	RR5	LC3	EH2	SP2	$OL7 \mid \overline{OD}$
	18	FAB	OD1	IRS	MUS	TPS	OL3	RRF	LCF	EH2	SP2	$OL7 \mid \overline{OD}$

Note (1): Conditional Split Fractions for L3(4), Support States 0, FA, FB

$OLF \mid \overline{IR}$ $LCF \mid \overline{IR}$

$OLF \mid \overline{OD}$

TABLE 5-6. SYSTEM QUANTIFICATION SUMMARY - SUPPORT TREE SPLIT FRACTIONS

TOP EVENT	SPLIT FRACTION	DESCRIPTION	MEAN FREQUENCY
GA	GA1	Train A Diesel failed given LOSP and RCS Condition W	1.4E-1
	GA2	Train A Diesel failed given LOSP and RCS Condition X	1.1E-1
	GAF	Train A Diesel failed given power to Bus E5 failed	1.0
GB	GB1	Train B Diesel failed given LOSP(W)	3.1E-1
	GBA	Train B Diesel failed given Diesel A success and LOSP(W)	3.0E-1
	GBB	Train B Diesel failed given Diesel A failed and LOSP(W)	3.3E-1
	GB2	Train B Diesel failed given LOSP(W)	1.1E-1
	GBC	Train B Diesel failed given Diesel A success and LOSP(X)	1.0E-1
	GBD	Train B Diesel failed given Diesel A failed and LOSP(X)	1.4E-1
	GBF	Train B Diesel failed given power to Bus E6 failed	1.0
PA	PA1	Train A PCC failed given RCS filled (W,Y)	1.4E-3
	PA2	Train A PCC failed given RCS drained (X)	1.3E-3
	PA3	Train A PCC failed given LOSP with RCS W	1.5E-3
	PA4	Train A PCC failed given LOSP with RCS X	1.3E-3
	PAF	Train A PCC failed given LPCC or LPCCA initiators	1.0
PB	PB1	Train B PCC failed given RCS filled (W,Y)	6.1E-2
	PBA	Train B PCC failed given Train A successful and RCS filled (W,Y)	6.1E-2
	PBB	Train B PCC failed given Train A failed and RCS filled (W,Y)	7.9E-2
	PB2	Train B PCC failed given RCS drained (X)	1.3E-3
	PBC	Train B PCC failed given Train A successful and RCS drained	1.3E-3
	PBD	Train B PCC failed given Train A failed and RCS drained	1.7E-3
	PB3	Train B PCC failed given LOSP(W)	6.1E-2
	PBE	Train B PCC failed given Train A successful and LOSP(W)	6.1E-2

TABLE 5-6. SYSTEM QUANTIFICATION SUMMARY - SUPPORT TREE SPLIT FRACTIONS

TOP EVENT	SPLIT FRACTION	DESCRIPTION	MEAN FREQUENCY
	PBG	Train B PCC failed given Train A failed and LOSP(W)	8.7E-2
	PB4	Train B PCC failed given LOSP(W)	1.3E-3
	PBH	Train B failed given Train A successful and LOSP(X)	1.3E-3
	PBI	Train B PCC failed given Train A failed and LOSP(X)	1.0E-2
	PBF	Train B PCC failed given LPCC initiator	1.0
WA	WA1	Train A Service Water failed given RCS filled (W,Y)	2.7E-4
	WA2	Train A Service Water failed given RCS drained (X)	2.5E-4
	WA3	Train A Service Water failed given LOSP with RCS W	2.2E-2
	WA4	Train A Service Water failed given LOSP with RCS X	2.0E-2
	WAF	Train A Service Water failed given LOSW or LSWA initiators	1.0
B	WB1	Train B SW failed given RCS filled	6.7E-3
	WBA	Train B SW failed given Train A success and RCS filled (W)	6.7E-3
	WBB	Train B SW failed given Train A failed and RCS filled (W)	1.0E-2
	WB2	Train B SW failed given RCS drained (X)	2.5E-4
	WBC	Train B SW failed given Train A success and RCS drained (X)	2.5E-4
	WBD	Train B SW failed given Train A failed and RCS drained (X)	2.4E-4
	WB3	Train B SW failed given LOSP(W)	8.2E-2
	WBE	Train B SW failed given Train A success and LOSP(W)	8.1E-2
	WBG	Train B SW failed given Train A failed and LOSP(W)	1.5E-1
	WB4	Train B SW failed given LOSP(X)	2.0E-2
	WBH	Train B SW failed given Train A success and LOSP(X)	1.9E-2
	WBI	Train B SW failed given Train A failed and LOSP(X)	5.5E-2
	WBF	Train B SW failed given LOSW	1.0

TABLE 5-7. TRANSIENT TREE SPLIT FRACTIONS

TOP EVENT	SPLIT FRACTION	DESCRIPTION	FREQUENCY
PC	PCF	$\overline{\text{PC}}$|Overpressure = A, B, or C	1.0
	PCS	PC|Overpressure = N <u>or</u> internal/external event	0.0
VO	VO1	$\overline{\text{VO}}$|Relief Valves = 2 or more (A)	3.0E-6
	VO2	$\overline{\text{VO}}$|Relief Valves = 1 (B)	4.3E-3
	VOF	$\overline{\text{VO}}$|Relief Valves = 0 (C)	1.0
OC	OC1	$\overline{\text{OC}}$	2.6E-2
SA	SAF	$\overline{\text{SA}}$|RHR3 or RHR4	1.0
	SAS	SA|RHR1, RHR2, RHR5, or RHR6	0.0
TP	TP1	$\overline{\text{TP}}$|$\overline{\text{PC}}$	3.7E-4
	TP2	TP|PC	1.7E-3
OR	OR1	$\overline{\text{OR}}$|RCS Condition W or Y	1.7E-5
	OR2	$\overline{\text{OR}}$|RHR5/ASSA/RCS Drained (X) <u>or</u> RHR5/Support A Failed/RCS Drained (X) <u>or</u> LPCCA, LSWA, FL1SG, LOSP, TCTL, FTBLP, FSGA/Support A Failed RHR3/ASSA/$\overline{\text{TP}}$/RCS Drained (X) RHR3/Support A Failed/$\overline{\text{TP}}$/RCS Drained (X)	1.7E-4
	OR3	$\overline{\text{OR}}$|RHR3/TP/RCS Drained (X)/(ASSA or Single Support Train Train Available) <u>or</u> RHR4/TP/RCS Drained (X)/(ASSA or Support Train B Failed)	1.7E-4
	OR4	$\overline{\text{OR}}$|RHR6/RCS Drained (X)/(ASSA or Single Support Train Available) <u>or</u> RHR5/RCS Drained/Support Train B Failed <u>or</u> RHR4/TP/RCS Drained/Support Train A Failed <u>or</u> RHR4/$\overline{\text{TP}}$/RCS Drained (X)/ASSA or Single Support Train Available <u>or</u> RHR3/$\overline{\text{TP}}$/RCS Drained (X)/Support Train B Failed <u>or</u> FETB/Support Train B Failed	4.3E-4
	OR5	$\overline{\text{OR}}$|RHR1/RCS Drained (X)/No Support Trains Available <u>or</u> RHR5/RCS Drained (X)/No Support Trains Avail. <u>or</u> RHR6/RCS Drained (X)/No Support Trains Avail. <u>or</u> RHR3/RCS Drained (X)/No Support Trains Avail. <u>or</u> RHR4/RCS Drained (X)/No Support Trains Avail. <u>or</u> LOSP, TCTL, FTBLP/No Support Trains Available <u>or</u> LPCCA, LSWA, FSGA, FETB, FL1SG/No Support Trains Avail. <u>or</u> LPCC, LOSW, FLSW, FETG, FLRHR, FPAB, FPCC	1.7E-3

TABLE 5-7. TRANSIENT TREE SPLIT FRACTIONS

TOP EVENT	SPLIT FRACTION	DESCRIPTION	FREQUENCY
OR	ORS	$\overline{OR}$|LOSP, TCTL, FTBLP/ASSA or LOSP, TCTL, FTBLP/Support Train B Failed	0.0
	ORF	FCRAC	1.0
RR	RR1	$\overline{RR}$|RHR1/ASSA/RCS Filled (W,Y)	4.4E-4
	RR2	$\overline{RR}$|RHR1/ASSA/RCS Drained (X)	2.3E-4
	RR3	$\overline{RR}$|RHR1/Support Train A Failed/RCS Filled (W,Y) or RHR3/Support Train A Failed (W,Y) or RHR3/$\overline{TP}$|ASSA/RCS Filled (W,Y) or RHR5/ASSA/RCS Filled (W,Y) or RHR5/Support Train A Failed/RCS Filled (W,Y)	1.2E-1
	RR4	$\overline{RR}$|RHR3/Support Train A Failed/RCS Drained (X) or RHR3/$\overline{TP}$/ASSA/RCS Drained (X) or RHR5/ASSA/RCS Drained (X) or RHR5/Support Train A Failed/RCS Drained (X)	8.9E-3
	RR5	$\overline{RR}$|RHR1/Support Train B Failed, or RHR2/ASSA, or RHR2/Support Train B Failed	9.3E-4
	RRZ	$\overline{RR}$|LOSP(X), TCTL(X), FTBLP(X)/ASSA	6.3E-4
	RR6	$\overline{RR}$|RR6 with RCS Condition W	2.3E-3
	RRY	$\overline{RR}$|LOSP(X), TCTL(X), FTBLP(X)/Support Train A Failed, or LPCCA(X), LSWA(X), FSGA(X), FLISG/Support Train A	8.9E-3
	RR7	$\overline{RR}$|$\overline{RR7}$ with RCS Condition W	1.2E-1
	RR8	$\overline{RR}$|LOSP, TCTL, FTBLP/Support Train B Failed, or RHR3/TP/Support Train B Failed or RHR4/TP/ASSA or RHR4/TP/Support Train B Failed	7.6E-3
	RR9	$\overline{RR}$| RHR3/TP/ASSA/RCS Filled (W,Y)	3.3E-3
	RRA	$\overline{RR}$| RHR3/TP/ASSA/RCS Drained (X)	6.6E-4
	RRF	$\overline{RR}$| RHR2/Support Train A Failed, or RHR4/Support Train A Failed, or RHR3/$\overline{TP}$/Support Train B Failed, or RHR4/$\overline{TP}$/ASSA,	1.0

TABLE 5-7. TRANSIENT TREE SPLIT FRACTIONS

TOP EVENT	SPLIT FRACTION	DESCRIPTION	FREQUENCY
RR		or RHR4/$\overline{TP}$/Support Train B Failed, or RHR5/Support Train B Failed, or RHR6 or No Support Available, or LOSP, TCTL, FTBLP/No Support Trains Available or LPCCA, LSWA, FL1SG, FSGA, FETB/No Support Train Available or LPCC, LOSW, FLSW, FCRAC, FETG, FPCC, FPAB, FLRHR	
LC	LC1	$\overline{LC}$|Procedure initiated event: ASSA, RCS Open (X) or LOSP(X), TCTL(X), FTBLP(X), FLRHR(X): ASSA, RCS Open (X)	2.3E-3
	LC2	$\overline{LC}$|Procedure initiated event: Support Train A Failed, RCS open (X) or LOSP(X), TCTL(X), FTBLP(X), LPCCA(X), LSWA(X), FETG(X), FSGA(X), FL1SG(X), FLRHR(X): Support Train Failed, RCS Open (X)	9.0E-3
	LC3	$\overline{LC}$|Procedure initiated event: Support Train B Failed, RCS open (X) or LOSP(X), TCTL(X), FTBLP(X), FLRHR(X), FETB(X): Support Train B Failed, RCS Open (X)	2.3E-3
	LC4	$\overline{LC}$|Procedure initiated event: No Support Trains Available, RCS open (X) or LOSP(X), TCTL(X), FTBLP(X), FLRHR(X), FSGA(X), FETB(X), LPCCA(X), LSWA(X), FETB(X), FPAB(X): No Support Train Avail., RCS Open (X) or FLSW(X), LPCC(X), LOSW(X), FPCC(X): RCS Open (X)	1.8E-2
	LC5	$\overline{LC}$|Same as LC1 except RCS Closed (W)	1.4E-7
	LC6	$\overline{LC}$|Same as LC2 except RCS Closed (W)	5.5E-7
	LC7	LC|Same as LC3 except RCS Closed (W)	1.4E-7
	LC8	$\overline{LC}$|Same as LC4 except RCS Closed (W)	8.7E-4
	LC9	$\overline{LC}$|Procedure initiated event - RCS at refueling level (Y)	1.0E-5
	LCF	$\overline{LC}$| FCRAC	1.0
EH	EH1	$\overline{EH}$|RCS condition W procedure initiators	2.9E-3
	EH2	$\overline{EH}$|RCS condition X procedure initiators or LPCCA(X), LSWA(X), LPCC(X), LOSW(X), FSGA(X), FETG(X), FETB(X), FPCC(X), FPAB(X), FLRHR(X)	5.1E-3

TABLE 5-7. TRANSIENT TREE SPLIT FRACTIONS

TOP EVENT	SPLIT FRACTION	DESCRIPTION	FREQUENCY
EH	EH3	$\overline{EH}$|RCS condition Y procedure initiators	2.1E-3
	EH4	$\overline{EH}$|FCRAC(X), LOSP(X), FLSW(X), FL1SG(X), TCTL(X), FTBLP(X)	1.1E-4
	EH5	$\overline{EH}$|LOCAs	3.8E-2
	EH6	$\overline{EH}$|Same as EH4 except RCS Condition W	3.3E-2
	EH7	$\overline{EH}$|Same as EH3 except RCS Condition W	3.5E-3
SP	SP1	$\overline{SP}$|Initiators with RCS Condition W	1.7E-2
	SP2	$\overline{SP}$|Initiators with RCS Condition X	4.0E-2

TABLE 5-8

SHUTDOWN LOCA SPLIT FRACTIONS

TOP EVENT	SPLIT FRACTION	DESCRIPTION	FREQUENCY
OD	OD1	$\overline{OD}\mid$L1, L5, L6, LS	1.6E-3
	OD2	$\overline{OD}\mid$L3	2.7E-4
	OD3	$\overline{OD}\mid$LP	1.6E-3
IR	IR1	$\overline{IR}\mid$L1, LP	8.1E-3
	IR2	$\overline{IR}\mid$L3	4.6E-4
	IRF	$\overline{IR}\mid$LS	1.0
	IRS	$\overline{IR}\mid$L5, L6	0.0
MU	MU1	$\overline{MU}\mid$(L1,LP) * (ASSA or Support Train B Failed)	4.7E-3
	MUF	$\overline{MU}\mid$L3,LS, or (L1,LP), * (Support A Failed or All Supports Failed)	1.0
	MUS	$\overline{MU}\mid$L5, L6	0.0
TP	TPA	$\overline{TP}\mid$(L1,LP) * IR	1.0E-4
	TPB	$\overline{TP}\mid$(L1,LP) * $\overline{IR}$ * $\overline{MU}$	2.2E-1
	TPS	$\overline{TP}\mid$(L1,LP) * $\overline{IR}$ * MU or L5, L6, L3	0.0
	TPF	$\overline{TP}\mid$LS	1.0
OL	OL1	$\overline{OL}\mid$(L1,LP) * IR	5.0E-5
	OL2	$\overline{OL}\mid$(L5,L6) * (ASSA or Single Support Train Avail.)	2.6E-4
	OL3	$\overline{OL}\mid$(L5,L6) * No Support Trains Avail.)	6.5E-4
	OL4	$\overline{OL}\mid$L3 * IR	6.5E-5
	OL5	$\overline{OL}\mid$LS * (ASSA or Single Support Train Failed)	8.5E-4
	OL6	$\overline{OL}\mid$(L1,LP) * $\overline{IR}$ * (ASSA or Single Support Train Failed)	4.3E-4
	OL7	$\overline{OL}\mid\overline{OD}$	9.5E-4
	OLF	$\overline{OL}\mid$(L1,LP) * ($\overline{IR}$ or $\overline{OD}$) * No Support Trains Avail. or LS * No Support Trains Avail. or L3 * ($\overline{IR}$ or $\overline{OD}$)	1.0
RR	RR1	$\overline{RR}\mid$(L5,L6) * ASSA	4.4E-4

TABLE 5-8

SHUTDOWN LOCA SPLIT FRACTIONS

TOP EVENT	SPLIT FRACTION	DESCRIPTION	FREQUENCY
RR	RR3	$\overline{RR}$|(L5,L6) * Support Train A Failed	1.2E-1
		or (L1,LP) * IR * (ASSA or Support Train A Failed)	
	RR5	$\overline{RR}$|(L5,L6) * Support Train B Failed	9.3E-4
	RRF	RR|No Support Trains Avail. or	1.0
		(L1,LP) * $\overline{IR}$ or	
		(L1,LP) * IR * Support Train B Failed or	
		or LS or L3	
LC	LC1	$\overline{LC}$|ASSA * [(L5,L6), LP * $\overline{IR}$ * MU)]	2.3E-3
	LC2	$\overline{LC}$|Support Train A Failed * [(L5, L6, LP * $\overline{IR}$ * MU)]	9.0E-3
	LC3	$\overline{LC}$|Support Train B Failed * [(L5,L6), LP * $\overline{IR}$ * MU]	2.3E-3
	LC5	$\overline{LC}$|ASSA * (L1,L3,LP) * IR	1.4E-7
	LC6	$\overline{LC}$|Support Train A Failed * (L1,L3,LP) * IR	5.5E-7
	LC7	$\overline{LC}$|Support Train B Failed * (L1,L3,LP) * IR	1.4E-7
	LCA	$\overline{LC}$|(ASSA or Support Train A Failed) * L1 * $\overline{IR}$ * MU	1.2E-1
	LCB	$\overline{LC}$|(ASSA or Support Train A Failed) * L1 * $\overline{IR}$ * $\overline{MU}$	2.4E-1
	LCC	$\overline{LC}$|LS * (ASSA or Support Train A Failed)	1.2E-1
	LCF	$\overline{LC}$|No Support Trains Available * (L1,L3,L5,L6,LP,LS)	1.0
		or Support Train B Failed * L1 * $\overline{IR}$	
		or Support Train B Failed * LS	
		or LP * $\overline{IR}$ * $\overline{MU}$ or L3 * $\overline{IR}$	
EH	EH2	$\overline{EH}$|L5, L6, L3	5.1E-3
	EH5	$\overline{EH}$|L1, LP, LS	3.8E-2
SP	SP2	$\overline{SP}$|L1, L5, L6, LS	4.0E-2
	SPF	$\overline{SP}$|LP, L3	1.0

TABLE 5-9

FREQUENCY CONTRIBUTIONS TO PROCEDURE-INITIATED EVENTS
FROM CASES A, B, AND C AND TREES 1 THROUGH 6

SHUTDOWN INITIATING EVENTS - PROCEDURE TREE LINKING
PHI(X) M : MATRIX OF PLANT DAMAGE STATE FREQUENCIES

	W1A	W3A	W3B	W3C	W3N	W5A	W5B	W5C	W5M	W6A
A1	3.28E-03	9.70E-06	1.71E-07	5.03E-11	1.01E-02	3.66E-05	1.90E-09	5.60E-13	3.73E-02	3.40E-03
A6	1.49E-02	2.73E-07	4.99E-09	4.50E-12	2.14E-04	4.11E-06	4.64E-12	4.19E-15	3.16E-03	0.00E+00
B1	6.28E-04	1.98E-07	3.42E-09	1.03E-13	1.43E-04	7.55E-07	4.11E-12	1.23E-16	5.18E-04	4.50E-04
B2	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
B5	2.23E-02	7.20E-07	3.71E-06	1.60E-06	1.16E-04	8.73E-05	1.45E-08	6.27E-09	1.67E-03	0.00E+00
B6	1.98E-03	3.55E-08	4.62E-09	3.24E-11	3.08E-05	5.44E-07	4.30E-12	3.02E-14	4.18E-04	0.00E+00
C1	1.39E-03	1.21E-05	2.63E-06	1.26E-10	8.69E-03	2.67E-06	5.01E-09	2.40E-13	1.57E-03	6.31E-04
C2	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.43E-03	0.00E+00	0.00E+00	0.00E+00	1.49E-03	0.00E+00
C3	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C4	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C5	4.79E-02	2.95E-06	1.31E-05	5.45E-06	3.96E-04	3.24E-04	9.91E-08	4.12E-08	5.90E-03	0.00E+00
C6	4.88E-03	4.24E-07	5.35E-08	3.76E-10	1.70E-04	6.51E-06	1.50E-10	1.65E-12	2.32E-03	0.00E+00
TOTAL	9.23E-02	2.65E-05	1.97E-05	7.05E-06	2.23E-02	4.63E-04	[illegible]E-07	4.75E-08	5.44E-02	4.68E-03

	W6B	W6C	W6M	X3M	X4M	X5M	X6M	Y3M	Y5M	L5
A1	4.12E-09	7.13E-11	1.43E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
A6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
B1	8.31E-11	1.44E-12	1.89E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
B2	0.00E+00	0.00E+00	0.00E+00	2.22E-02	0.00E+00	1.66E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
B5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
B6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C1	5.12E-09	1.11E-09	3.48E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C2	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.32E-03	5.23E-03	1.41E-04
C3	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C4	0.00E+00	0.00E+00	0.00E+00	3.93E-02	3.09E-03	4.57E-02	6.02E-04	0.00E+00	0.00E+00	0.00E+00
C5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
TOTAL	9.33E-09	1.18E-09	1.96E-03	6.15E-02	3.09E-03	6.24E-02	6.02E-04	1.32E-03	5.23E-03	1.41E-04

	L6	TOTAL
A1	0.00E+00	5.55E-02
A6	0.00E+00	1.83E-02
B1	0.00E+00	1.85E-03
B2	0.00E+00	3.89E-02
B5	0.00E+00	2.42E-02
B6	0.00E+00	2.43E-03
C1	0.00E+00	1.28E-02
C2	0.00E+00	3.93E-03
C3	1.74E-05	5.71E-03
C4	0.00E+00	8.87E-02
C5	0.00E+00	4.96E-02
C6	0.00E+00	7.37E-03
TOTAL	1.74E-05	3.10E-01

TOTAL CORE MELT FREQUENCY IS 3.10E-01

TABLE 5-10

SPLIT FRACTIONS AND TRANSFER SEQUENCE FREQUENCIES
FOR SHUTDOWN CASE A (TREES 1 AND 6)

Tree 1: Cooldown to Cold Shutdown

Initiating Frequency	Tree 1 Top Events						
	RV	CT	RI	LT	RM	SA	NC
3.4 per year	RV1	CT1	RI1	LT1	RM1	SA1[(a)]	NC1[(b)]

(a) SA2 if event CT fails

(b) NC2 if event RM or SA fails

Tree 6: Cold Startup

Initiating Frequency	Tree 6 Top Events					
	LI	LT	SA	RM	CT	IS
3.4 per year	LI1	LT6	SAC[(a)]	RMA	CT1	IS1

(a) SAD if event LT fails

TABLE 5-11

SPLIT FRACTIONS AND TRANSFER SEQUENCE FREQUENCIES FOR SHUTDOWN CASE B (TREES 1, 2, 5, AND 6)

Tree 1: Cooldown to Cold Shutdown

Initiating Frequency	Tree 1 Top Events						
	RV	CT	RI	LT	RM	SA	NC
0.45 per year	RV1	CT1	RI1	LT2	RM2	SA1[a]	NC3[b]

(a) SA2 if event CT fails

(b) NC4 if event RM or SA fails

Tree 2: RCS Draindown

Initiating Frequency	Tree 2 Top Events						
	TV	DR	LM	VA	IO	SA	RM
0.45 per year	TV1	DR1	LM1	VA1	IO1	SA3	RM4

Tree 5: RCS Fill

Initiating Frequency	Tree 5 Top Events							
	TL	CT	LM	CC	LT	PU	SA	RM
0.45 per year	TL1	CT2[a]	LM5	CC1[b]	LT4	PU1	SA8[c]	RM8

(a) CT4 if event TL fails
(b) CC2 if event CT fails
(c) SA9 if event LT fails

TABLE 5-11

SPLIT FRACTIONS AND TRANSFER SEQUENCE FREQUENCIES FOR SHUTDOWN CASE B (TREES 1, 2, 5, AND 6

Tree 6: Cold Startup

Initiating Frequency	Tree 6 Top Events					
	LI	LT	SA	RM	CT	IS
0.45 per year	LI1	LT7	SAC[(a)]	RMA	CT2	IS1

(a) SAD if event LT fails.

TABLE 5-12

SPLIT FRACTIONS AND TRANSFER SEQUENCE FREQUENCIES
FOR SHUTDOWN CASE C (TREES 1 THROUGH 6)

Tree 1: Cooldown to Cold Shutdown

Initiating Frequency	Tree 1 Top Events						
	RV	CT	RI	LT	RM	SA	NC
0.83 per year	RV1	CT1	RI1	LT3	RM3	SA1[(a)]	NC5[(b)]

(a) SA2 if event CT fails

(b) NC6 if event RM or SA fails

Tree 2: RCS Draindown

Initiating Frequency	Tree 2 Top Events						
	TV	DR	LM	VA	IO	SA	RM
0.83 per year	TV1	DR2	LM2	VA1	IO2	SA4	RM5

Tree 3: Refueling Cavity Fill

Initiating Frequency	Tree 3 Top Events			
	DF	CS	SA	RM
0.83 per year	DF1	CS1	SA5	RM6

TABLE 5-12

SPLIT FRACTIONS AND TRANSFER SEQUENCE FREQUENCIES FOR SHUTDOWN CASE C (TREES 1 THROUGH 6)

Tree 4: Refueling Cavity Drain

Initiating Frequency	Tree 4 Top Events						
	CD	BR	DM	RF	LM	SA	RM
0.83 per year	CD1	BR1	DM1	RF1	LM3[a]	SA6[b]	RM7

(a) LM4 if event DM fails

(b) SA7 if event DM fails

Tree 5: RCS Fill

Initiating Frequency	Tree 5 Top Events							
	TL	CT	LM	CC	LT	PU	SA	RM
0.83 per year	TL1	CT2[a]	LM6	CC1[b]	LT5	PU2	SAA[c]	RM9

(a) CT3 if event TL fails
(b) CC2 if event CT fails
(c) SAB if event LT fails

Tree 6: Cold Startup

Initiating Frequency	Tree 6 Top Events					
	LI	LT	SA	RM	CT	IS
0.83 per year	LI2	LT8	SAE[a]	RMB	CT2	IS1

(a) SAG if event LT fails

TABLE 5-13

SUMMARY OF PROCEDURAL EVENT TREE SPLIT FRACTIONS

TREE	TOP EVENT	SPLIT FRACTION	DEPENDENCIES	TOTAL FREQUENCY
1	RV	RV1		1.0E-3
	CT	CT1		1.7E-2
	RI	RI1		4.2E-4
	LT	LT1	$\overline{LT}$ | Case A	3.0E-4
		LT2	$\overline{LT}$ | Case B	3.0E-5
		LT3	$\overline{LT}$ | Case C	4.8E-5
	RM	RM1	$\overline{RM}$ | Case A	1.1E-2
		RM2	$\overline{RM}$ | Case B	1.2E-3
		RM3	$\overline{RM}$ | Case C	1.9E-3
	SA	SA1	$\overline{SA}$ | Case A	3.0E-3
		SA2	$\overline{SA}$ | Case B	3.2E-4
		SA3	$\overline{SA}$ | CT, Case C	8.8E-3
		SA4	$\overline{SA}$ | $\overline{CT}$, Case C	1.1E-1
	NC	NC1	$\overline{NC}$ | Case A	9.8E-4
		NC2	$\overline{NC}$ | Case B	1.4E-3
		NC3	$\overline{NC}$ | Case C	1.7E-3
2	TV	TV1		1.0E-3
	DR	DR1	$\overline{DR}$ | Case B	3.1E-3
		DR2	$\overline{DR}$ | Case C	0.0
	LM	LM1	$\overline{LM}$ | Case B	8.6E-4
		LM2	$\overline{LM}$ | Case C	3.1E-4
	VA	VA1		0.0
	IO	IO1	$\overline{IO}$ | Case B	1.5E-2
		IO2	$\overline{IO}$ | Case C	7.4E-4
	SA	SA5	$\overline{SA}$ | Case B	3.2E-2

TABLE 5-13

SUMMARY OF PROCEDURAL EVENT TREE SPLIT FRACTIONS

TREE	TOP EVENT	SPLIT FRACTION	DEPENDENCIES	TOTAL FREQUENCY
		SA6	$\overline{SA}$|Case C	8.9E-4
	RM	RM4	$\overline{RM}$|Case B	3.7E-2
		RM5	$\overline{RM}$|Case C	1.8E-3
3	DF	DF1		2.1E-5
	CS	CS1		1.7E-4
	SA	SA7		1.6E-3
	RM	RM6		6.3E-3
4	CD	CD1		3.1E-3
	BR	BR1		1.3E-2
	DM	DM1		3.4E-2
	RF	RF1		3.1E-3
	LM	LM3	$\overline{LM}$|DM	8.6E-4
		LM4	$\overline{LM}$|$\overline{DM}$	3.1E-4
	SA	SA8	$\overline{SA}$|DM	4.8E-2
		SA9	$\overline{SA}$|$\overline{DM}$	2.7E-2
	RM	RM7		5.6E-2
5	TL	TL1		1.3E-2
	CT	CT2	$\overline{CT}$	7.4E-3
	LM	LM5	$\overline{LM}$|Case B	2.2E-3
		LM6	$\overline{LM}$|Case C	3.4E-3
	CC	CC1		2.9E-2
	LT	LT4	$\overline{LT}$|Case B	4.8E-3
		LT5	$\overline{LT}$|Case C	4.9E-3
	PU	PU1	$\overline{PU}$|Case B	6.3E-3

TABLE 5-13

SUMMARY OF PROCEDURAL EVENT TREE SPLIT FRACTIONS

TREE	TOP EVENT	SPLIT FRACTION	DEPENDENCIES	TOTAL FREQUENCY
		PU2	$\overline{PU} \mid$ Case C	7.6E-3
	SA	SAA	$\overline{SA} \mid LT$ * Case B	2.7E-4
		SAB	$\overline{SA} \mid \overline{LT}$ * Case B	1.0E-3
		SAC	$\overline{SA} \mid LT$ * Case C	5.0E-4
		SAD	$\overline{SA} \mid \overline{LT}$ * Case C	2.0E-3
	RM	RM8	$\overline{RM} \mid$ Case B	3.9E-3
		RM9	$\overline{RM} \mid$ Case C	7.5E-3
6	LI	LI1	$\overline{LI} \mid$ Case A, B	1.3E-3
		LI2	$\overline{LI} \mid$ Case C	2.8E-3
	LT	LT6	$\overline{LT} \mid$ Case A	2.4E-4
		LT7	$\overline{LT} \mid$ Case B	3.0E-2
		LT8	$\overline{LT} \mid$ Case C	3.0E-2
	SA	SAE	$\overline{SA} \mid LT$ * Case A, B	6.3E-5
		SAG	$\overline{SA} \mid \overline{LT}$ * Case A, B	2.5E-4
		SAH	$\overline{SA} \mid LT$ * Case C	1.9E-4
		SAI	$\overline{SA} \mid \overline{LT}$ * Case C	7.3E-4
	RM	RMA	$\overline{RM} \mid$ Case A, B	9.3E-4
		RMB	$\overline{RM} \mid$ Case C	2.8E-3
	CT	CT1	$\overline{CT} \mid$ Case A	1.7E-2
		CT2	$\overline{CT} \mid$ Case B, C	7.4E-3
	IS	IS1		3.1E-3

TABLE 5-14

CORE DAMAGE FREQUENCY DISTRIBUTIONS

	FREQUENCEY DISTRIBUTION (per year)				
	Mean	Variance	5th	50th	95th
Core Damage Total	4.4E-5	1.6E-8	5.9E-6	2.0E-5	1.3E-4
Plant Damage States					
R2D	3.8E-5	1.5E-8	4.0E-6	1.5E-5	1.2E-4
R2P	1.4E-6	1.8E-11	9.1E-8	5.1E-7	4.6E-6
R2H	4.4E-7	9.7E-13	4.8E-8	2.5E-7	1.3E-6
R6D	4.4E-6	6.8E-11	3.6E-7	2.1E-6	1.[illegible]-5
R6P	[illegible].3E-7	7.4E-14	7.2E-9	5.[illegible]E-8	4.9E-6
R6H	1.1E-7	2.5E-14	6.4E-[illegible]	5.0E-8	4.5E-7

6.0 OPERATOR ACTION ANALYSIS

The operator actions analysis in this section provides an input to the quantification of event tree top events. The actual event trees and their top events are described in Sections 3 and 4 for the plant response model and the procedure initiated events model, respectively. Quantification of these models is documented in Section 5. The results of this section are a direct input to these appendices where human error and hardware failure probabilities are combined as necessary.

Two types of operator actions or responses are evaluated. The first type is actions associated with normal shutdown procedures. Event tree models are developed in Section 4 to identify potential operator errors that lead to an initiating event such as loss of RHR. The second type is operator actions in response to initiating events. As can be seen in the results presented in Section 3, the need to distinguish between these two types of actions is particularly important in the case of shutdown. Event tree models in Section 3 evaluate plant response to initiating events such as operator action and equipment required to provide feed and bleed cooling.

Section 6.1 describes the methodology used for operator actions analysis. Sections 6.2 and 6.3 describe the quantification of operator errors associated with the procedure initiated model and plant response model, respectively. Results are summarized in Tables 6-1, 6-2, and 6-3. Section 6.4 describes operator error quantification used in the systems analysis (Section 7) in the containment analysis (Section 10.1), or resulting in an initiating event, with a summary in Table 6-4.

6.1 Methodology

The human reliability analysis consist of the following steps:

- initial task analysis
- screening quantification
- final quantification
- uncertainty analysis

The initial task analysis involved reviewing the shutdown evolution procedures to identify sources of initiating events - loss of RHR, overpressurization, and LOCA events - that could be caused by operator errors. This information was used to create the initial procedural event trees. Also, the steps to respond to an initiating event were examined in creating the plant response event trees. The shutdown procedures and resulting event trees are described in Section 3 and 4.

The top events in the initial event trees were quantified in a screening analysis using human error rates from NUREG/CR-1278 (Ref. 17) where a human error probability (HEP) could be easily identified. Otherwise, the events were classified as skill-based, rule-based, or knowledge-based actions consistent with NUREG/CR-4772 (Reference 18). The screening values of HEPs used for these three classes of events were 0.001, 0.01, and 0.1, respectively. For events where the boundary between two classes was fuzzy, the nominal HEP was adjusted upwards or downwards as the situation dictates. In addition, adjustments were made to account for dependence between 2 or more actions in the same sequence. As a result of this initial screening quantification, several top events were eliminated (due to hardware failures that dominated) or were refined to account for the critical error in the step.

Using the final event tree top events, the human error probabilities were quantified using the quantification methodology adopted from NUREG/CR-1278, "The Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications" (the "Handbook", Reference 17). This single reference was used in order to anchor all the HEPs to a single, consistent method and to consistently treat groups of actions that differ only with time available to complete the action. Also, the "Handbook" was judged to be appropriate for operator errors during shutdown because the same types of basic human errors are important during shutdown as during operation. Each operator top event was analyzed in terms of basic HEPs contained in the "Handbook". This final quantification methodology is described in more detail in the following sections.

The uncertainty distribution assigned for each point value estimated HEP was based on guidance provided by the "Handbook". The point estimate HEP is assumed to be the median of a lognormal distribution with the appropriate error factor estimate from the "Handbook". The frequency distributions shown in Tables 6-1 through 6-4 are the results of a Monte Carlo combination of the input lognormal distributions.

Another level of uncertainty analysis was performed to account for the dependency on the time to core uncovery which is a function of the time after shutdown. In general, the HEPs were estimated conservatively assuming the shortest feasible time after shutdown. This time dependency was modeled in Transient and LOCA tree top events OR and OL - operator diagnosis (see Section 6.2). An uncertainty model, documented in Section 5.6, accounts for the longer times available for operator diagnosis and recovery as the time after shutdown increases. The time-point estimated HEPs for OR and OL were adjusted based on the results of the uncertainty analysis. Other best estimate analyses are included in the uncertainty analysis for the operator actions that show up in the dominate sequences.

6.1.1 Final Human Error Probability Assessments

The final assessment of human reliability is performed by identifying the nominal HEP from the "Handbook" (Ref. 17) that applies to the situation. In general, it is assumed that average industrial conditions exist; that operators have nominal training and experience; and that human factors of displays are satisfactory. The nominal HEPs are adjusted to account for non-optimal stress (low or high) and for dynamic versus step-by-step actions. They are also adjusted to account for dependencies on previous operator successes or failures.

The key factors for quantifying human reliability include some or all of the following for each operator action:

- Quality of procedures
- Quality of information - instrumentation and alarms
- Time for diagnosis and recovery
- Stress level for routine or dynamic actions
- Dependencies - previous successes or failures
  - multiple alarms

The factors that influence each specific operator action are described in Sections 6.2 through 6.4. In addition, each nominal HEP and adjustment factor used for an operator top event are referenced to specific tables and items in the "Handbook" so that the quantification can be reproduced.

6.1.2 Human Errors During Shutdown Procedures

Human errors during normal plant evolutions which may cause an initiating event are described and quantified in Section 6.3. There are several general types of errors that are characteristic of these actions.

An error of omission, the operator skipping a critical step in a plant evolution procedure, can result in an immediate event or may remain undetected until another event occurs. This error is quantified from the "Handbook", Table 20-7.

Several errors of commission were identified: check-reading displays (Table 20-11), operating manual controls or selecting the wrong circuit breaker (Table 20-12), and selecting locally operated valves (Table 20-13). Also, failures to recover from an error of commission were quantified as HEPs for failing to detect errors made by others (Table 20-22).

These and other tables in the "Handbook" were referenced in quantifying the operator actions in Section 6.2.

6.1.3 Human Errors During Response to Shutdown Plant Transients

Human errors during shutdown in response to a transient event are described and quantified in Section 6.2. In general, these are operator errors during initial response, diagnosis, and long term response to the event.

The initial operator response to a transient can mitigate its effects even prior to full diagnosis. These include tripping a cavitating RHR pump, controlling an overpressurization, and isolation RHR in the event of a LOCA. The operator errors associated with initial response include failing to detect and respond to multiple alarms (Handbook Table 20-23) or deviant displays (Table 20-25).

The operator failure to diagnose is based on the "Handbook" Figure 12-4 (and the related Table 20-3). This figure provides probability of failure to diagnose as a function of time after a compelling signal of an abnormal situation. The time available to diagnose is estimated as the time to core overheating minus the time to begin to respond.

The operator failures in the long term response are failures of commission - operating manual controls or selecting the wrong circuit breakers (Table 20-12), or selecting locally operated valves (Table 20-13).

The basic HEPs for the above failures are modified to account for stress level (Table 20-16) and/or dependencies from previous successes or failures (Tables 20-18, 19).

6.1.4 Uncertainty Distributions

The uncertainty parameter - the error factor (EF) - given for each basic HEP in Chapter 20 of the "Handbook" is used to generate an uncertainty distribution. Where the uncertainty parameter is not given, the estimated uncertainty bounds for general classes of HEPs are taken from Table 20-20 ("Handbook"). (For example, for step-by-step procedural tasks carried out in non-routine circumstances with moderately high stress and the estimated HEP less than 0.001, the estimated error factor is 10. [Table 20-20, Item 5, Ref. 17]). The error factor is assumed to be equal to the ratio of the 95th percentile to the median (or the ratio of the median to the 5th percentile) in a lognormal distribution. The point value best estimate (BE) HEP is taken to be the median of this distribution. These two parameters (BE, EF) are sufficient to define the lognormal distribution.

The distributions for HEPs were developed using the general guidelines of the "Handbook" and assuming lognormality to account for uncertainty.

Where shutdown procedures exist (i.e.. for plant evolutions), the procedures are in somewhat draft condition and operators have not been trained since the use of such procedures (e.g., refueling) is several years aw.. Other procedures (accident response at shutdown) have not yet been written. As a result, it was judged appropriate to estimate only one parameter (the best estimate) and use the general guidelines of the "Handbook" to assign an error factor. This resulted in a consistent methodology for creating distributions about the best estimate. Also, use of the best estimate as the median of a log-normal distribution resulted in a mean value that is greater than the best estimate by a factor ranging from 1.25 for an error factor of 3 to a factor of 8.5 for an error factor of 30. Thus, use of the log-normal and rather large error factors resulted in mean significantly larger than the median, conservatively reflecting the uncertainty.

6.2 Quantification of Plant Response Actions

Using the methodology in Section 6.1, the operator error probabilities are calculated for the plant response tree top events. This includes the shutdown transient tree in Section 6.2.1 and the shutdown LOCA tree in Section 6.2.2. These probabilities are combined in Appendix E with hardware contributions to determine the total top event split fraction. Tables 6-1 and 6-2 summarize the results of operator action quantification for the plant response trees.

Each operator action variable is quantified by estimating the median (best estimate = BE) and the range of the distribution (error factor = EF) as discussed previously. It is assumed that the operator action variables are lognormally distributed based on the characteristics of this distribution (e.g., it ranges from 0+ to infinity; it is skewed to the right so that the mean is greater than the median). Using these two parameters (BE,EF), the mean of the distribution can be computed as follows:

$$\text{mean} = BE * \exp[1/2 * (\ln EF/1.645)^2]$$

where:

$$BE = \text{median} = X_{50}$$

$$EF = \text{error factor} = \frac{X_{95}}{X_{50}}$$

The quantification of specifications is provided in the sections below:

6.2.1 <u>Shutdown Transient Tree</u>

1. OP_{OC} - operator fails to control the source of overpressurization. The operator fails to isolate charging and/or to increase letdown after an RHR relief valve or pressurizer PORV lifts and before substantial liquid mass has escaped from the RCS. The operator alert level will be very high and detection good because of the alarms and indications (level, temperature in the PRT, LTOP alarm, pressurizer level and pressure, and RHR discharge pressure). Operator fails to control overpressurization by tripping the wrong pump and failing to detect his error. The time available before substantial inventory loss is estimated to be greater than 60 min, (based on 500 gpm (flow through one relief) * 60 min = 30,000 gal). Thus, T = 60 min.

   o OP_{OC} = OP1 + OP2 * NR = 9.5E-4 (mean)

   where:

   OP1 = operator fails to diagnose plant condition (overpressure) and the source of overpressure and fails to determine a successful course of action within 60 min.

   = 8.5E-4 (mean)

   BE = 1.0E-4 (Table 20-3, Item 5, Ref. <u>17</u>)

   EF = 30 (same ref.)

   OP2 = operator trips non-operating charging pump - selecting wrong control from an array of controls with well defined mimic layout.

= 1.3E-3 (mean)

BE = 5.0E-4 (Table 20-12, Item 4, Ref. 17)

EF = 10 (same ref.)

NR = operator fails to recover from error OP2. Expected response is directly coupled to to action. Operator is performing short term checking with alerting factors.

= 8.0E-2 (mean)

BE = 0.05 (Table 20-22, Item 3, Ref. 17)

EF = 5 (same ref.)

2. OP_{TP} - operator fails to detect RHR pump operating in a degraded suction mode (vortexing or cavitation) or trips wrong pump.

$OP1_{TP}$ - The failure to trip the pump is due to the operator failing to respond to the low flow alarm in time to prevent pump damage, or the operator responding but tripping the wrong pump. Tripping the wrong pump is not a credible failure because of the separation between RHR trains on the MCB with flow meters clearly associated with each train. This operator action to trip the pump is a simple, routine action. With no associated overpressure event, the quality of information is high because of the single (or few) alarm. The time available is assumed to be at least 30 min. based on evidence from historical events (see Section 9.3).

o $OP1_{TP}$ = $\overline{TP}|$No Overpressure Condition

= OP1 + OP2 * NR = 3.7E-4 (mean)

where:

OP1 = operator fails to respond to VAS alarm.

= 2.7E-4 (mean)

BE = 1.0E-4 (Table 20-23, Item 1, Ref. 17)

EF = 10 (Table 20-20, Item 6, Ref. 17)

OP2 = operator trips wrong pump - selects wrong control from panel with good mimics.

= 1.3E-3

BE = 5.0E-4 (Table 20-12, Item 4, Ref. 17)

EF = 10 (same ref.)

NR = operator fails to recover from OP2. Operator is performing short term checking with alert factors.

= 8.0E-2 (mean)

BE = 0.05 (Table 20-22, Item 3, Ref. 17)

EF = 5 (same ref.)

$OP2_{TP}$ - If the pump suction situation is accompanied with an overpressurization, the VAS low flow alarm indicating the suction valves are closed will be accompanied with additional alarms due to overpressure (RCS filled, solid or a bubble in pressurizer) The operator must respond to the multiple alarms and must diagnose the pump cavitation problem in addition to the overpressu

o $OP2_{TP} = \overline{TP}|\overline{PC} = OP1' + OP2 * NR$

= 1.7E-3 (mean)

where:

OP1' = operator fails to respond to cavitating pump alarm (low flow) given prior overpressure alarm (fail to respond to second of two alarms)

= 1.6E-3 (mean)

BE = 1.0E-3 (Table 20-23, Item 2, Ref. 17)

EF = 5 (Table 20-20, Item 7, Ref. 17)

OP2 = operator trips wrong pump (same as OP2 for $OP1_{TP}$)

= 1.3E-3 (mean)

NR = operator fails to recover from OP2 (same as NR for $OP1_{TP}$)

= 8.0E-2 (mean)

3. OP_{OR} - operator fails to determine that decay heat removal capability has been lost or operator chooses a decay heat removal mode that is not viable. This action includes perceiving that there is a plant upset condition, discriminating from other potential sources of upset, inter-

preting the alarms and indications, diagnosing the most likely cause of the event, and deciding on the "best" success path. This action is modeled as a function of the time available to core uncovery. The analyses below are done for the earliest time after shutdown, i.e., for the highest decay heat level and, thus, for the shortest time available. A correction factor is included to account for the variability in time after shutdown. The correction factors are based on the uncertainty analysis in Section 5.6.

OR1 - For loss of (operating) RHR in the RCS Condition W or Y, the RCS is full and intact (or in refueling) and at least two steam generators are available for cooling. The decay heat can be removed via natural circulation for many hours (> 10 hours). The operator action is very reliable because of the time and the additional resources that will be made available. The dependencies from previous operator actions are accounted for in the time available; see below. Optimal stress is assumed. Time available equals:

T = 12 hrs (time to steam gen. dryout for 4 S/Gs, 1 day after shutdown - Appendix B, Fig. B-6)

\+ 3 hrs (time to core uncovery, 1 day after shutdown - Appendix B, Fig. B-4)

\+ 2 hrs (time to core damage after uncovery, 3 days after shutdown - Appendix B, Fig. B-3)

\- 1.0 hr (time to restart failed pumps)

\- 0.5 hr (time to begin makeup)

= 15.5 hr available (930 min)

o OR1 = $\overline{OR}$|RCS Conditions W or Y

= OR * MD * CF = 1.7E-5 (mean)

where

OR:BE = OR (T = 930 min.) = 1.3E-5 (Figure 12-4, Ref. 17)

OR:EF = 30 (same ref.)

MD = 0.15 (Failure of second shift of operators to diagnose plant status, assuming moderate dependency between first and second shifts - Table 20-18, footnote three, Ref. 17)

CF = 1.0 (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OR2 - For the RCS Condition X, the operator has as little as 3 hours to dete ine a course of action (OR) and then implement it (RR,LC). Time available equals:

T = 2 hrs (time to core uncovery, 3 days after shutdown - Appendix B, Fig. B-1)

+ 2 hrs (time to core damage after core uncovery, 3 days after shutdown, Appendix B, Fig. B-3)

- 0.5 hr (time to restart failed pump)

- 0.5 hr (time to begin makeup)

= 3 hrs available (180 min)

For the scenario with the operating pump failed (hardware failure) and the standby pump available (RHR5), annunciator alarms immediately alert the operator to the loss of flow or the loss of cooling. Also, he can continue on normal RHR using the standby pump. The dependency with previous failures (e.g., failure to trip) is accounted for in time. Also optimal stress is assumed.

o OR2 = $\overline{OR}$|(RCS Condition X, RHR5 or 3, $\overline{TP}$)

= OR * CF = 1.7E-4 (mean)

where

OR:BE = OR (T = 180 min) = 4.0E-5 (Table 20-3, Item 5, Ref. 17)

OR:EF = 30 (same ref.)

CF = 0.5 (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OR3 - For the RCS Condition X with RHR pump vortexing (RHR3 or 4) but successful operator action in TP to trip the pump, the operator has immediate awareness of the loss of cooling. It may require some time to restore level and restart the normally operating RHR pump. Time available equals:

T = 2 hrs (time to core uncovery - see OR2)

+ 2 hrs (time to core damage - see OR2)

- 10 min (time to trip pump)

- 0.5 hrs (time to begin makeup)

= 200 min available

The dependency with previous operator actions is accounted f · in time T . Optimal stress is assumed.

o OR3 = $\overline{OR}$|(RCS Condition X, RHR3 or 4, TP)

= OR * CF = 1.7E-4 (mean)

where

OR:BE = OR (T = 200 min.) = 4.0E-5 (Figure 12-4, Ref. 17)

OR:EF = 30 (same ref.)

CF = 0.5 (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OR4 - For the RCS Condition X with both the operating and the standby RHR pumps failed due to hardware causes (RHR6), the operator has immediate awareness of the loss of cooling. Procedure calls for makeup from RWST to ensure level above hot leg midplane. Makeup may be from charging pump or gravity feed. Time available equals:

T = 2 hrs (time to core uncovery - see OR2)

+ 2 hrs (time to core damage - see OR2)

- 30 min (time to try to restart 1st pump)

- 15 min (time to try to start 2nd pump)

- 30 min (time to begin makeup)

= 165 min available

Thus, the best estimate for OR:

OR (T = 165 min) = 5.0E-5 (Figure 12-4, Ref. 17)

Moderately high stress is assumed, with a stress factor:

F_S = 2 (Table 20-16, Item 4, Ref. 17) o OR4 = $\overline{OR}$|(RCS Condition X, RHR6 or 4, $\overline{TP}$)

= OR * F_S * CF = 4.3E-4 (mean)

where

OR:BE = OR (T = 165 min.) = 5.0E-5

OR:EF = 30 (Figure 12-4, Ref. <u>17</u>)

CF = 0.5 (Corection Factor for time-dependent uncertainty analysis - see Section 5.6)

OR5 - For the RCS Condition X with loss of both support systems, the operator is immediately aware of the loss of cooling and aware of the status of the RHR pumps. His stress level will be high because of the limited options he has for long term cooling. However, gravity feed from RWST will provide core cooling for many hours while alternative cooling strategies are being formulated. The time available equals:

T = <u>2 hrs</u> (time to core uncovery - see OR2)

\+ <u>2 hrs</u> (time to core damage - see OR2)

\- <u>0.5 hr</u> (time to try to restore support systems)

\- <u>0.5 hr</u> (time to begin makeup)

= <u>3 hrs</u> available (180 min)

Thus, best estimate for OR:

OR (T = 180 min.) = 4.0E-5 (Table 20-3, Item 5, Ref. <u>17</u>)

Assuming extremely high stress, the stress factor is:

F_S = 5 (Table 20-16, Item 6, Ref. <u>17</u>)

o OR5 = $\overline{OR}$|RCS Condition X, No Support Systems Avail.

= OR * F_S * CF

= 1.7E-3 (mean)

where

OR:BE = OR (T = 180 min.) = 4.0E-5

OR:EF = 30 (Table 20-3, Item 5, Ref. <u>17</u>)

CF = 1.0 (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

ORF - Guaranteed operator failure for severe fires, seismic events.

o ORF = 1.0

ORS - With the RHR pump operating (RHR1 or 2), the operator must continue to maintain decay heat removal. No diagnosis is needed.

ORS = $\overline{OR}$|RHR1,2 = 0.0

6.2.2 Shutdown LOCA Tree

1. OD - Operator fails to detect a LOCA prior to substantial inventory loss from the primary system.

OD1 - For LOCAs L1, L5, L6, and LS, the operator has multiple alarms and indications of water in containment - PRT level and temperature, sump level, etc. Detection is immediate and clear. The time available, based on LOCA LS, is T = 10 min. Operator responses to multiple annunciator alarms clearly in time and must distinguish overpressure alarms from LOCA alarms (for L. - other LOCAs do not have multiple alarm sets).

o OD1 = $\overline{OD}$|L1,L5,L6,LS = 1.6E-3 (mean)

BE = 6.0E-4 (Table 20-23, Item 2, Ref. 17) - arithmetic mean.

EF = 10 (Table 20-20, Item 6, Ref. 17)

- For LOCA L3, the operator gets immediate alarms of excess water returning to the RWST (low pressurizer level, high RWST level). The time available is short, T = 10 min.

OD2 = $\overline{OD}$|L3 = 2.7E-4 (mean)

BE = 1.0E-4 (Table 20-23, Item 1, Ref. 17)

EF = 10 (Table 20-20, Item 8, Ref. 17)

OD3 - For LOCA LP, the operator must detect the RHR pump seal failure from indirect indications (RHR vault sump alarm).

The leak is small so more time is available T = 60 min.).

Operator must respond to the second of two annunciator alarm sets - overpressure is first, then low VCT level due to small LOCA at RHR pump seal.

o $OD3 = \overline{UD}|LP = 1.6E-3$ (mean)

$BE = 1.0E-3$ (Table 20-23, Item 2, Ref. 17)

$EF = 5$ (Table 20-20, Item 7, Ref. 17)

2. OP_{IR} - Operator fails to isolate the RHR suction valves RH-V22 or 23, and RH-V87 or 88 given he successfully detected the LOCA. Isolation is the expected action once the operator has detected the loss of inventory since the RHR cooling loop is the most likely source of leakage.

$OP1_{IR}$ - For LOCAs L1 and LP, the operator has time to isolate RHR; T = 30 min. Operator error is based on omitting a step in the LOCA response procedure, for a short list with no check-off provisions.

$OP1_{IR} = \overline{IR}|L1,LP$

$= 3.8E-3$ (mean)

$BE = 3.0E-3$ (Table 20-7, Item 3, Ref. 17)

$EF = 3$ (same ref.)

$OP2_{IR}$ - For LOCA L3, the alarms (low pressurizer level, high RWST level) are clearly coupled with opening the suction valves. The operator's instinctive action is to reset the previous action at once in response to the alarm.

$OP2_{IR} = \overline{IR}|L3$

$= 2.7E-4$ (mean)

$BE = 1.0E-4$ (Table 20-23, Item 1, Ref. 17)

$EF = 10$ (Table 20-20, Item 6, Ref. 17)

3. OP_{TP} - Operator fails to trip the running RHR pump before pump damage occurs from loss of suction.

OP_{TPA} - For LOCAs L1 and LP with top event IR successful, the operator must trip the pump in a short time to prevent pump damage. He is alert due to success of IR. The time available is assumed to be at least 30 min. based on evidence from historic events (see Section 9.3).

Based on the success of IR, it is assumed the operator will trip the RHR pump instinctively. The error is tripping the wrong switch and failing to recover (OP2 and NR from $OP1_{TP}$ in Section 6.2.1).

$$OP_{TPA} = \overline{TP}|(L1,LP) * IR$$

$$= OP2 * NR = 1.0E\text{-}4 \text{ (mean)}$$

OP_{TPB} - For LOCAs L1 and LP with top events IR and MU failed, the operator must trip the pump before it fails from vortexing. The operator has a higher failure probability because of previous errors, but has ample alarms and indications to alert him to the LOCA. Assuming moderate dependence and a basic HEP of 1.0E-4 (from above):

$$OP_{TPB} = \overline{TP}|(L1,LP) * \overline{IR} * \overline{MU} = 0.22 \text{ (mean)}$$

BE = 0.14 (Table 20-18, Items 6,7, Ref. 17)

EF = 5 (Table 20-20, Item 5, Ref. 17)

OP_{TPF} - For LOCA LS, top event TP is a guaranteed failure. Since LS is a large, energetic LOCA, insufficient time is available to trip the operating RHR pump before vortexing.

$$OP_{TPF} = \overline{TP}|LS = 1.0$$

OP_{TPS} - For LOCAs L5 and L6, it is not necessary for the operators to trip the pump since the RCS inventory cannot drain below the vessel flange. For LOCA L3, the RHR pumps are not yet running per procedure. These are modeled as guaranteed successful.

o $OP_{TPS} = \overline{TP}|L3,L5,L6 = 0.0$

Also, for L1 and LP with IR failed and MU successful, it is not necessary to trip the pumps. One charging pump can maintain level.

o $OP_{TPS} = \overline{TP}|(L1,LP) * \overline{IR} * MU = 0.0$

4. OL - Operator fails to determine appropriate actions to restore decay heat removal before core damage occurs. This action is modeled as a function of the time available to core uncovery. The analyses below are done for the earliest time after shutdown and a correction factor is used to account for the variability in time after shutdown. The correction factors are based on the uncertainty analysis in Section 5.6.

OL1 - For LOCAs L1 and LP, if the operator successfully isolates RHR (IR), he has a number of hours with passive secondary cooling to get RHR or alternate cooling operable. The time available is modeled as:

T = 12 hr (time to S/G dryout with 4 S/Gs, 1 day after shutdown - see Appendix B, Fig. B-6)

+ 3 hr (time to core uncovery, level at flange, 1 day after shutdown - see Appendix B, Fig. B-2)

+ 2 hr (time to core damage, 3 days after shutdown - see Appendix B, Fig. B-3)

- 0.5 hr (time to begin makeup)

= 16.5 hr (990 min)

Optimal stress is assumed because of the long time available.

o OL1 = $\overline{OL}|(L1,LP) * IR$

= OL * CF

= 5.0E-5 (mean)

where

OL:BE = OL (T = 990 min) = 1.2E-5 (Fig. 12-4, Ref. 17)

OL:EF = 30 (same ref.)

CF = 0.5 (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OL2 - For LOCAs L5 and L6, RHR is maintained and the operator has a moderately high stress level due to loss of refueling level with potential uncovered fuel elements. This recovery is a step-by-step action (starting the standby pump if necessary). Thus, the stress factor is:

F_S = 2 (Table 20-16, Item 4, Ref. 17)

The time available equals:

T = 3.7 hr (time to core uncovery 3 days after shutdown with level at the vessel flange - see Appendix B, Fig. B-2)

+ 2 hr (time to core damage, 3 days after shutdown - see Appendix B, Fig. B-3)

- 0.5 hr (time to begin makeup)

= 5.2 hr (310 min)

Thus,

$OL\ (T = 310\ \text{min}) = 3.0E\text{-}5$ (Fig. 12-4, Ref. 17)

o $OL2 = \overline{OL}|L5,L6 *$ (ASSA or Single Support Train Avail.)

$= OL * CF * F_S$

$= 2.6E\text{-}4$ (mean)

where

$OL{:}BE = OL\ (T = 310\ \text{min}) = 3.0E\text{-}5$

$OL{:}EF = 30$ (Fig. 12-4, Ref. 17)

$CF = 0.5$ (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OL3 - For LOCAs L5 and L6, if RHR cannot be restored, the operator has a higher stress level but has time to plan long term cooling (feed and boil off). It is assumed moderately high stress level with dynamic actions needed to recover cooling. Thus, the stress factor is:

$F_S = 5$ (Table 20-16, Item 5, Ref. 17)

The time available is the same as above, $T = 310$ min.

Thus,

$OL\ (T = 310\ \text{min}) = 3.0E\text{-}5$ (Fig. 12-4, Ref. 17)

o $OL3 = \overline{OL}|L5,L6 *$ (No Support Trains Avail.)

$= OL * F_S * CF$

$= 6.5E\text{-}4$ (mean)

where

$OL{:}BE = OL\ (T = 310\ \text{min}) = 3.0E\text{-}5$

$OL{:}EF = 30$ (Fig. 12-4, Ref. 17)

$CF = 0.5$ (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OL4 - For LOCA L3, if IR is successful, the time available for operator action is:

T = $\underline{16\ hr}$ (Time to core uncovery 12 hr after shutdown with 4 S/Gs - see Appendix B, Fig. B-6) - $\underline{0.5\ hr}$ (Time to begin makeup) = $\underline{15.5\ hr}$ (930 min)

Because of the long time available, it is assumed that the operators have optimal stress.

o OL4 = $\overline{OL}|L3 * IR$

= OL * CF

= 6.5E-5 (mean)

where

OL:BE = OL (T = 930 min) = 1.5E-5

OL:EF = 30 (Fig. 12-4, Ref. 17)

CF = 0.5 (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OL5 - For LOCA LS, the leak is assumed to be unisolated. Thus, the operator action is identify low pressure injection/recirculation. The time available equals:

T = $\underline{2\ hr}$ (time to core uncovery, 3 days after shutdown, drained to hot leg - see Appendix B, Fig. B-1)

+ $\underline{2\ hr}$ (time to core damage, 3 days after shutdown - see Appendix B, Fig. B-3)

- $\underline{0.5\ hr}$ (time to begin makeup) = $\underline{3.5\ hr}$ (210 min)

OL (T = 210 min) = 4.0E-5 (Fig. 12-4, Ref. 17)

Moderately high stress with dynamic actions is assumed. Thus, the stress factor is:

F_S = 5 (Table 20-16, Item 5, Ref. 17)

o OL5 = $\overline{OL}|LS$ * (ASSA or Single Support Train Failed)

= OL * F_S * CF

= 8.5E-4 (mean)

OL:BE = OL (T = 210 min) = 4.0E-5

OL:EF = 30 (Table 20-3, Item 5, Ref. 17)

CF = 0.5 (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OL6 - For LOCA L1 and LP, if IR is failed, the time available equals:

T = 1.5 hr (Time to core uncovery 1 day after shutdown, drained to hot leg - see Appendix B, Fig. B-1)

+ 2 hr (time to core damage, 3 days after shutdown - see Appendix B, Fig. 3)

- 0.5 hr (time to begin makeup) = 3.0 hr (360 min)

Thus,

OL (T = 360 min) = 2.0E-5 (Fig. 12-4, Ref. 17)

Moderately high stress and dynamic actions are assumed. Thus, the stress factor is:

F_S = 5 (Table 20-16, Item 5, Ref. 17)

o OL6 = $\overline{OL}|(L1,LP) * \overline{IR}$

= OL * F_S * CF

= 4.3E-4 (mean)

where

OL:BE = OL (T = 360 min) = 2.0E-5

OL:EF = 30 (Fig. 12-4, Ref. 17)

CF = (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OL7 - For any LOCA, if the initial detection (OD) is failed, time available equals:

T = 1.5 hr (Time to core uncovery 1 day after shutdown, drained to hot leg - see Appendix B, Fig. B-1)

+ 2 hr (time to core damage 3 days after shutdown - see Appendix B, Fig. B-3)

- 1.0 hr (time to fail to diagnose)

- 30 min (time to begin makeup)

= 2.0 hr (120 min). Thus,

OL (120 min) = 4.5E-5 (Fig. 12-4, Ref. 17).

Moderately high stress and dynamic actions are assumed.

Thus, the stress factor is:

F_S = 5 (Table 20-16 Item 5, Ref. 17)

o OL7 = $\overline{OL}|\overline{OD}$

= OL * F_S * CF

= 9.5E-4 (mean)

where

OL:BE = OL (120 min) 4.5E-5

OL:EF = 30

CF = 0.5 (Correction Factor for time-dependent uncertainty analysis - see Section 5.6)

OLF - For L3 with IR failed, a short time is available for recovery. It is conservatively assumed to be a guaranteed failure.

o OLF = $\overline{OL}|L3 * \overline{IR}$ = 1.0

For L1 and LP with IR failed or for LS, with no support trains available, it is assumed that there are no long term cooling options.

o OLF = $\overline{OL}|(L1,LP) * \overline{IR}$ * No Support Trains Available, or

LS * No Support Trains Available = 1.0

6.3 Quantification of Shutdown Procedure Actions

Using the methodology in the previous sections, the operator error probabilities are calculated for the procedure event tree top events. These probabilities are combined in Appendix D with the hardware contributions to determine the total split fraction quantification. Table 6-3 summarizes the results of operator action quantification for procedure event trees.

6.3.1 Operator Actions for Tree 1

1. OP_{RV} - Operator attempts to open both RHR suction valves with RCS pressure greater than 450 psig. The shutdown procedure instructs the operator to open the RHR suction valves between 365 psig (the suction valves interlock setpoint) and 325 psig (the low NPSH criteria for RCPs). This is a sensitive setpoint for the operators because of possible damage

to RCPs. Also, the operators are using a wide range pressure indicator and have a band of only 40 psig, or 2% of scale. The operator may attempt to open the suction valves early, relying on the interlocks to prevent opening. However, operator opening the valves at pressure above 450 psig is a much less likely error.

o $OP1_{RV}$ = OP1 = 3.8E-3 (mean)

where:

OP1 = operator skips a procedural step, and opens suction valves early, given normal pressure indication but a faulty pressure interlock.

BE = 0.003 (Table 20-7, Item 3, Ref. 17)

EF = 3 (Table 20-7, Item 3, Ref. 17)

o $OP2_{RV}$ = OP2 = 1.0

where:

OP2 = operator opens the suction valves at an indicated pressure of less than 365 psig, given a faulty pressure indication.

mean = 1.0

o $OP3_{RV}$ = OP3 = 4.5E-2 (mean)

where:

OP3 = operator fails to detect pressure transmitter failure. Operator fails to detect deviant display during hourly control board scan.

BE = 0.028 (Table 20-25, Item 2(a)-(h), Ref. 17)

EF = 5 (Table 20-20, Item 3, Ref. 17)

*2. OP_{CT} - operator fails to have the cross-train alignment (CT) for the RHR suction valves implemented or auxiliary operator (AO) fails to setup alignment correctly (leaves at least one of two valves powered).

o $OP1_{CT}$ = OP1 + (1-OP1) * (OP2 * NR2 + OP3 * NR3)

= 1.7E-2 (mean)

---

* Quantification of OP_{CT} is based on procedural modifications to setup the suction valve depowering on both RHR trains.

where:

OP1 = operator fails to have procedure step carried out

= 0.013 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

OP2 = auxiliary operator fails to remove power from correct valve in Train A RHR:

= 0.0063 (mean)

BE = 0.005 (Table 20-12, Item 11, Ref. 17)

EF = 3 (Table 20-12, Item 11, Ref. 17)

NR2 = Control Room operator fails to notice the white indicator light is still on

= 0.32 (mean)

BE = 0.2 (Table 20-22, Item 2, Ref. 17)

EF = 5 (Table 20-22, Item 2, Ref. 17)

OP3 = auxiliary operator fails to remove power from the second valve (in Train B RHR) given that the first was depowered (assuming Moderate Dependence):

= 0.005 (mean)

BE = 0.004 (Table 20-19, Item 5, Ref. 17)

EF = 3 (Table 20-12, Item 11, Ref. 17)

NR3 = Control Room operator fails to notice white indication light is still on

= 0.32 (mean)

BE = 0.2 (Table 20-22, Item 2, Ref. 17)

EF = 5 (Table 20-22, Item 2, Ref. 17)

3. OP_{RI} - operator fails to correctly start RHR pump or operator fails to open RHR discharge isolation valve, operator fails to start first pump:

$OP1_{RI}$ = (OP1 + OP2) * NR = 4.0E-3 (mean)

where:

OP1 = operator fails to correctly start first RHR pump (e.g., fails to vent)

= 3.8E-3 (mean)

BE = 0.003 (Table 20-7, Item 3, Ref. 17)

EF = 3 (Table 20-7, Item 3, Ref. 17)

OP2 = operator fails to open discharge isolation valve, skips procedural step. (Long list, no checkoff provisions).

= 1.3E-2 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

NR = operator fails to recover from failure before pump overheats and fails, given unannunciated deviant display (analog meter without limit modes, initial audit).

= 0.24 (mean)

BE = 0.15 (Table 20-25, Item 2, Ref. 17)

EF = 5 (Table 20-20, Item 2, Ref. 17)

Operator fails to start second RHR pump given first pump failed:

$OP2_{RI}$ = (OP1 + OP2) * NR' = 1.3E-3 (mean)

where:

OP1 = operator fails to start pump

= 3.8E-3 (mean)

OP2 = operator fails to open discharge isolation valve

= 1.3E-2 (mean)

NR' = operator fails to recover from error given first pump is failed (previous failure serves to alert operator):

$= 0.08$ (mean)

BE = 0.05 (Table 20-22, Item 3, Re . 17)

EF = 5 (Table 20-22, Item 3, Ref. 17)

4. OP_{SA} - operator fails to remove power from valves during test or maintenance of the RHR suction valves. This failure is dependent on top event CT and is applicable during Case C only.

$OP1_{SA} = \overline{SA}|CT$ - operator fails to remove power from the valve that remain powered the cross-train alignment, when performing test of each pressure transmitter.

o $OP1_{SA} = (OP1 * NR1)_A + (OP1 * NR1)_B$

$= 8.3E-3$ (mean)

where:

OP1 = operator fails to depower each of two RHR suction valves (skip procedural step, long list, no checkoff):

$= 1.3E-2$ (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

NR1 = operator in control room fails to realize suction valves remain powered during test/ maintenance (routine checking without written material)

$= 0.32$ (mean)

BE = 0.2 (Table 20-22, Item 2, Ref. 17)

EF = 5 (Table 20-22, Item 2, Ref. 17)

$OP2_{SA} = \overline{SA}|\overline{CT}$ - operator fails to remove power from both suction isolation valves for each RHR train. (All remain powered since CT is failed).

o $OP2_{SA} = 2 * (OP1 + OP2) * NR1 = 0.11$ (mean)

where:

OP1 = 1.3E-2 (mear) - above

OP2 = operator fails to detect and remove power from the RHR suction valve which is expected to be depowered.

= 0.16

BE = 0.1 (Table 20-22, Item 1, Ref. 17)

EF = 5 (Table 20-22, Item 1, Ref. 17)

NR1 = 0.32 (mean) - above

5. NR_{NC} - operator fails to recover from hardware-induced excess charging event.

- $NR1_{NC}$ - operator fails to recover from inadvertent SI overpressurization for Case A (bubble in pressurizer). The time available equals

$$T = \frac{720\ ft^3 \text{ in pressurizer steam volume } * 7.5 \text{ gal per } ft^3}{500 \text{ gpm maximum flow from one charging pump}}$$

$= 10.8$ min

The inadvertent SI would be accompanied by a compelling signal of an abnormal situation. Thus,

$NR1_{NC}$ = 0.27 (mean)

BE = 0.1 (Table 20-3, Item 2, Ref. 17)

EF = 10 (Table 20-3, Item 2, Ref. 17)

- $NR2_{NC}$ - operator fails to recover from hardware failure resulting in isolation of letdown. This failure would not (necessarily) be alarmed. The failure would have to be detected by observing increasing level in the pressurizer. The time available:

$$T = \frac{720\ ft_3 \text{ in pressurizer steam volume } * 7.5 \text{ gal per } ft_3}{70 \text{ gpm maximum letdown flow}}$$

$= 77$ min

Assuming an hourly scan of the pressurizer level (analog meter without limit marks), the operator has two scans prior to overpressurization.

$NR2_{NC}$ = 0.11 (mean)

BE = 0.07 (Table 20-25, Item 2, Ref. 17)

EF = 5 (Table 20-20, Item 5, Ref. 17)

- o $NR3_{NC}$ - operator fails to recover from hardware failures resulting in maximum charging through the normal makeup path. The failure would be detected by observing increasing level in the pressurizer. The time available:

$$T = \frac{720 \text{ ft}^3 \text{ in pressurizer steam volume} * 7.5 \text{ gal/ft}^3}{120 \text{ gpm maximum makeup}}$$

$$= 45 \text{ min}$$

Assuming an hourly scan of the pressurizer level, the operator has one scan prior to overpressurization.

$NR3_{NC}$ = 0.24 (mean)

BE = 0.15 (Table 20-25, Item 2, Ref. 17)

EF = 5 (Table 20-20, Item 5, Ref. 17)

6.3.2 Operator Actions for Tree 2

1. OP_{TV} - Operator fails to install temporary level transmitter properly and fails to detect this error when comparing readings with LI-462.

o OP_{TV} = OP1 * OP2 = 1.0E-3 (mean)

where:

OP1 = temporary level transmitter installed improperly by AOs (omits step in installation procedure, e.g., venting air). Assume written procedures are available but may not be used (skill of the trade).

= 0.08 (mean)

BE = 0.05 (Table 20-7, Item 5, Ref. 17)

EF = 5 (Table 20-7, Item 5, Ref. 17)

OP2 = comparison of readings performed incorrectly by AO and control room operator, given the tube was installed improperly. Operator omits step in long list without checkoff.

= 0.013 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

2. OP_{DR} - Operator fails to reduce RHR flow to 1000 gpm to prevent vortexing at the hot leg level. This action is necessary only for Case B. Operator omits procedural step in long list without checkoff and fails to recover g n 30 min. to recover.

$OP1_{DR}$ = $\overline{DR}$|Case B

o $OP1_{DR}$ = OP1 * NR1 = 3.1E-3 (mean)

where:

OP1 = operator fails to reduce flow, omits procedural step:

= 0.013 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

NR1 = operator fails to recover from error OP1 before RHR pump cavitates, given analog meter deviant display, without limit marks (i.e., flow).

= 0.29 (mean)

BE = 0.15 (Table 20-25, Item 2, Ref. 17)

EF = 5 (Table 20-20, Item 3, Ref. 17)

o $OP2_{DR}$ = $\overline{DR}$|Case C = 0.0

3. OP_{LM} - Operator fails to maintain level after draining down. It is assumed that the operator must make three adjustments in establishing level. This error is dependent on the level of water in the vessel - Case B a the hot leg mid-plane, and Case C at the top of the vessel flange.

$OP1_{LM}$ = $\overline{LM}$|Case B

o $OP1_{LM}$ = 3 * OP1 * NR1 = 8.6E-4 (mean)

where:

OP1 = operator fails to maintain level with the water level at the hot leg nozzle mid-plane. Operator set rotary switch to incorrect setting.

= 1.3E-3 (mean)

BE = 0.001 (Table 20-12, Item 9, Ref. 17)

EF = 3 (Table 20-12, Item 9, Ref. 17)

NR1 = operator fails to recover from error OP1 before RHR pump cavitation, given pre-vortexing alarm. Operat must perform same action as in OP1. A ume moderate dependency.

= 0.22 (mean)

BE = 0.14 (Table 20-18, Item 6, Ref. 17)

EF = 5 (Table 20-20, Item 3, Ref. 17)

$OP2_{LM}$ = $\overline{LM}$|Case C

o $OP2_{LM}$ = 3 * OP1 * NR2 = 3.1E-4 (mean)

where:

OP1 = operator fails to maintain level with level at the vessel flange. (Same as OP1 above)

= 1.3E-3 (mean)

NR2 = operator fails to recover from error OP1 before pump cavitation, given prevortexing alarm. Because of longer time available, low dependency assumed.

= 0.08 (mean)

BE = 0.05 (Table 20-18, Item 6, Ref. 17)

EF = 5 (Table 20-20, Item 3, Ref. 17)

. OP_{VA} - Operator fails to vent RCS to atmosphere.

o OP_{VA} = 0.0 based on installation of delta pressure measurement for level monitoring

5. OP_{SA} - Operator fails to control level over the mission time in tree 2, resulting in RHR pump cavitation. It is assumed that the operator must adjust level once per 24 hours. The operator error probability depends on the time in tree 2. It is also dependent on the RCS water level - Case B at the hot leg nozzle midplane and Case C at the vessel flange.

o $OP3_{SA} = \overline{SA}|\text{Case B } (T_M = 922 \text{ hr})$

$$= \frac{t}{24} * OP1 * NR1 = 2.2E-2 \text{ (mean)}$$

where:

t = time in tree 2, Case B = T_M = 959 hr

OP1 = operator fails to control level with level at the hot leg midplane. Operator sets rotary switch to incorrect setting. The basic HEP (BE) = 0.001 (Table 20-12, Item 9, Ref. <u>17</u>). Very low stress level is assumed F_S = 2 (Table 20-16, Item 1, Ref. <u>17</u>).

= 2.5E-3 (mean)

BE = HEP * F_S = 2.0E-3

EF = 3 (Table 20-12, Item 9, Ref. <u>17</u>)

NR1 = operator fails to recover from error OP1 before pump cavitation, given prevortexing alarm. Assume moderate dependence.

= 0.22 (mean)

BE = 0.14 (Table 20-18, Item 6, Ref. <u>17</u>)

EF = 5 (Table 20-20, Item 3, Ref. <u>17</u>)

o $OP4_{SA} = \overline{SA}|\text{Case C } (T_M = 47 \text{ hr})$

$$= \frac{t}{24} * OP1 * NR2 = 3.9E-4 \text{ (mean)}$$

where:

t = time in tree 2, Case C = 47 hr

OP1 = operator fails to control level with level at the vessel flange (same as OP1 above).

= 2.5E-3 (mean)

NP2 = operator fails to recover, given prevortexing alarm. Because of longer time available, low dependency is assumed.

= 0.08 (mean)

BE = 0.05 (Table 20-18, Item 6, Ref. 17)

EF = 5

6.3.3 Operator Actions for Tree 3

1. OP_{DF} - Operator fails to close SF-V-81, resulting in a loss of inventory from the refueling cavity.

o OP_{DF} = (OP1 + OP2 * NR) * OP3 = 2.1E-5 (mean)

where:

OP1 = operator starts to fill refueling cavity prior to having valve SF-V-81 (refueling cavity drain valve) closed and blocked off. Operator omits a procedural step - no signoff required, long list.

= 0.013 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

OP2 = auxiliary operator fails to close valve and fails to install flange. Operator fails to recall oral instructions (one of two actions).

= 1.3E-3 (mean)

BE = 1.0E-3 (Table 20-8, Item 6, Ref. 17)

EF = 3 (Table 20-8, Item 6, Ref. 17)

NR = independent verification fails to detect valve open and flange off.

= 0.16 (mean)

BE = 0.1 (Table 20-22, Item 1, Ref. 17)

EF = 5 (Table 20-22, Item 1, Ref. 17)

OP2 = operator fails to detect leakage to containment sumps (sump alarm), given valve is open. Assume addition random alarm.

BE = 0.001 (Table 20-23, Item 2, Ref. 17)

EF = 5 (Table 20-20, Item 7, Ref. 17)

2. OP_{CS} - technician fails to install cavity seal correctly.

o OP_{CS} = OP1 * NR1 = 1.7E-4 (mean)

where:

OP1 = the cavity seal is installed incorrectly and results in loss of inventory. Operator skips a procedural step.

= 0.013 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

NR1 = the cavity seal installation is not inspected and leak is not detected. Operator skips a procedural step in testing.

= 0.013 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

6.3.4 Operator Actions for Tree 4

1. OP_{CD} - Operator fails to close RH-V21 or RH-V33, valves in the RWST refilling path.

o OP_{CD} = OP1 * (OP1' + OP2) = 3.1E-3 (mean)

where:

OP1 = operator skips procedural step to close RH-V21, given alarm at vessel level (4" below flange). Short list (based on alarm). no checkoff provisions.

= 0.013 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

OP1' = operator skips the ste~ in the pr~cedure which says to close m~ ~al valve RH-V33, given lower level of alert. Long list, no checkoff provision. Moderate dependence. The basic HEP = 0.01 from abov~.

= 0.24 (mean)

BE = 0.15 (Table 20-18, Item 4, Ref. 17)

EF = 5 (Table 20-20, Item 3, Ref. 17)

OP2 = auxiliary operator fails to close correct valve (RH-V33). Operator fails to recall oral instructions.

= 0.0013 (mean)

BE = 0.001 (Table 20-8, Item 1, Ref. 17)

EF = 3 (Table 20-8, Item 1, Ref. 17)

2. OP_{BR} - Operator fails to realign RHR Train B f~~ cooling by opening RH-V26 (discharge isolation valve).

   o OP_{BR} = operator skips a procedural step to open RH-V26; long list, no checkoff provision.

   = 1.3E-2 (mean)

   BE = 1.0E-2 (Table 20-7, Item 4, Ref. 17)

   EF = 3 (Table 20-7, Item 4, Ref. 17)

3. OP_{RF} - Operator fails to reduce RHR flow to 1000 gpm. (Same quantification as $OP1_{DR}$ in Section 6.3.2).

   o OP_{RF} = OP1 * NR1 = 3.1E-3 (mean)

4. OP_{LM} - Operator fails to achieve the desired level. Operator error probability depends on the desired level (DM successful, level at hot leg nozzle midplane; DM failed, level at head flange). It is assumed that it requires three operator adjustments to achieve level. (Same quantification as $OP1_{LM}$ and $OP2_{LM}$ in Section 6.3.2).

   o $OP3_{LM}$ = $\overline{LM}|DM$ = 3 * OP1 * NR1

   = 8.6E-4 (mean)

   o $OP4_{LM}$ = $\overline{LM}|\overline{DM}$ = 3 * OP1 * NR2

   = 3.1E-4 (mean)

5. OP_{SA} = Operator fails to control level over the mission time in tree 4 and results in RHR pump failure (vortexing). It is assumed that the operator adjusts level once per 24 hours. Operator error probability heavily depends on the desired vessel level (DM successful, level is at hot leg nozzle midplane; DM failed, level at vessel head flange).

o $OP6_{SA}$ = $\overline{SA}|DM$ (T_M = 1440 hrs) = 3.3E-2 (mean)

= t/24 * OP1 * NR1

OP1 = operator fails to maintain desired level given level at hot leg midplane. (Same quantification as OP1 for OP_{SA} in Section 6.3.2).

= 2.5E-3 (mean)

NR1 = operator fails to recover from adjustment error prior to RHR pump failure, given prevortexing alarm. (Same quantification as NR1 for OP_{SA} in Section 6.3.2).

= 0.22 (mean)

o $OP7_{SA}$ = $\overline{SA}|\overline{DM}$ = 1.2E-2 (mean)

= t/24 * OP1 * NR2 (t = 1440 hr)

OP1 = operator fails to maintain level at vessel flange. (Same as OP1 above).

= 2.5E-3 (mean)

NR2 = operator fails to recover before level drops 7 ft. and RHR pump failure (vortexing) occurs. (Same quantification as NR2 for OP_{SA} in Section 6.3.2).

= 0.08 (mean)

6.3.5 Operator Action for Tree 5

1. OP_{TL} - Temporary level transmitter - operator fails to verify that LI-9405 and temporary level transmitter give same readings initially.

o OP_{TL} = operator fails to align temporary level transmitter reading, given transmitter has failed.

= 1.3E-2 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

2. OP_{CT} - Operator fails to ensure that the cross-train alignment is in effect. It is assumed that there is one test and maintenance of the RHR suction valves during the outage. Thus, the cross-train alignment could be misaligned because it was misaligned in tree 1 and not restored in tree 5 or because it was misaligned due to test and maintenance and not restored in tree 5.

o $OP2_{CT}$ = (OP1 + OP2) * NR1 = 7.4E-3 (mean)

where:

OP1 = operator fails to correctly align power to suction valves (see $OP1_{CT}$ in Section 6.3.1).

= 1.3E-2 (mean)

OP2 = test and maintenance error resulting in suction valve depowering misaligned. Assume written procedures are available but may not be used.

= 0.08 (mean)

BE = 0.05 (Table 20-7, Item 5, Ref. 17)

EF = 5 (Table 20-7, Item 5, Ref. 17)

NR1 = operator fails to detect misalignment, given it is a prerequisite to fill procedure.

= 0.08 (mean)

BE = 0.05 (Table 20-22, Item 2, Ref. 17)

EF = 5 (Table 20-22, Item 2, Ref. 17)

3. OP_{LM} - Operator fails to maintain level at 45', resulting in filling the pressurizer and overpressurization. It is assumed that the operator must adjust level once every 24 hours. The failure probability depends on the length of time in the tree.

o $OP5_{LM}$ = $\overline{LM}$|Case B (T_M = 101 hr)

$$= (OP1 + \frac{t}{24} * OP2) * NR1 = 2.2E-3 \text{ (mean)}$$

where:

OP1 = auxiliary operator fails to read temporary level transmitter correctly or fails to alert control room that the required level has initially been reached. Operator fails to read analog meter correctly

= 0.0038 (mean)

BE = 0.003 (Table 20-11, Item 4, Ref. 17)

EF = 3 (Table 20-11, Item 4, Ref. 17)

OP2 = operator fails to maintain charging/letdown balance, given bubble in pressurizer. Operator sets rotary control to incorrect setting.

= 1.[illegible]-3 (mean)

BE = 0.001 (Table 20-12, Item 9, Ref. 17)

EF = 3 (Table 20-12, Item 9, Ref. 17)

NR1 = operator fails to recover before significant overpressure. Operator fails to detect unannunciated deviate display.

= 0.24 (mean)

BE = 0.15 (Table 20-25, Item 2, Ref. 17)

EF = 5 (Table 20-20, Item 7, Ref. 17)

o $OP6_{LM} = \overline{LM}|\text{Case C } (T_M = 184 \text{ hr})$

$= (OP1 + \frac{t}{24} * OP2) * NR1 = 3.4E-3$ (mean)

where:

t = time in tree 5, Case C = 193 hr

4. OP_{CC} - Operator fails to correctly cross-calibrate LI-462 (pressurizer level) with temporary level transmitter.

o $OP1_{CC} = OP1 + OP2 = 2.9E-2$ (mean)

where:

OP1 = operator skips calibration step in procedure; long list, no checkoff provision.

= 0.013

BE · 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

OP2 = I&C technican incorrectly calibrates LI-462, skips step where written procedures are available but not used - task is "second nature".

= 0.016 (mean)

BE = 0.01 (Table 20-7, Item 5, Ref. 17)

EF = 5 (Table 20-7, Item 5, Ref. 17)

5. OP_{LT} = Operator fails to restore PT403 and PT405 to service.

o $OP4_{LT}$ = $OP5_{LT}$ = OP1 + OP2 * NR = 4.7E-3 (mean)

where:

OP1 = operator skips procedural step to restore PT403 and PT405. Long list, with checkoff provisions.

= 0.0038 (mean)

BE = 0.003 (Table 20-7, Item 2, Ref. 17)

EF = 3 (Table 20-7, Item 2, Ref. 17)

OP2 = I&C technician fails to properly restore PT403/405.

= 0.0038 (mean)

BE = 0.003 (Table 20-13, Item 2, Ref. 17)

EF = 3 (Table 20-13, Item 2, Ref. 17)

NR = operator fails to detect PTs not restored. Operator fails to detect deviant display of analog meter without limit modes

= 0.24 (mean)

BE = 0.15 (Table 20-25, Item 2, Ref. 17)

EF = 5 (Table 20-20, Item 7, Ref. 17)

6. OP_{PU} - Operator fails to maintain pressurizer level at pressure of 325 psia. It is assumed that the operator must make three adjustments to charging in tree 5 to maintain level during evolutions.

o $OP1_{PU}$ = $OP2_{PU}$ = 3 * OP1 = 3.9E-3 (mean)

where:

OP1 = operator fails to maintain level.

= 0.0013 (mean)

BE = 1.0E-3 (Table 20-12, Item 9, Ref. 17)

EF = 3 (Table 20-12, Item 9, Ref. 17)

6.3.6 Operator Actions for Tree 6

1. OP_{LI} - Operator fails to control excess letdown during heatup, resulting in filling the pressurizer and an overpressurization. This event depends on the length of time in tree 6. For Cases A and B (T_M = 24 hr), it is assumed that there are 5 demands for operator action to increase letdown. Four demands occur when pressure is low and recovery is good. One demand occurs as the pressure increases to 300 psig where recovery is not as easy.

$OP1_{LI}$ = $\overline{LI}$|Case A,B

= 4 * OP1 * NR1 + 1 * OP1 * NR2 = 9.0E-4 (mean)

where:

OP1 = operator fails to control level. Operator sets rotary control to incorrect setting.

= 1.6E-3 (mean)

BE = 0.001 (Table 20-12, Item 9, Ref. 17)

EF = 5 (Table 20-12, Item 9, Ref. 17)

NR1 = operator fails to recover from overfill prior to overpressurization, given the pressure is low. Assume low dependency OP1.

= 0.08 (mean)

BE = 0.05 (Table 20-18, Item 6, Ref. 17)

EF = 5 (Table 20-20, Item 7, Ref. 17)

NR2 = operator fails to recover from overfill, given the pressure is high. Assume moderate dependency with OP1.

= 0.24 (mean)

BE = 0.15 (Table 20-18, Item 6, Ref. 17)

EF = 5 (Table 20-20, Item 7, Ref. 17)

For Case C (T_M = 72 hr), it is assumed there are 8 demands to maintain level - 3 with pressure low and 5 with pressure high.

o $OP2_{LI}$ = $\overline{LI}|$Case C

= 3 * OP1 * NR1 + 5 * OP1 * NR2 = 2.3E-3 (mean)

where OP1, NR1, and NR2 are from above.

2. OP_{IS} - operator fails to isolate RHR.

OP_{IS} = OP1 * OP2 = 3.1E-3 (mean)

where:

OP1 = operator fails to close one of two valves prior to depowering; long list, no checkoff procedures.

= 0.013

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

OP2 = operator fails to close second suction valve, given he failed to close first valve. Assume moderate dependency.

= 0.24

BE = 0.15 (Table 20-18, Item 4, Ref. 17)

EF = 5 (Table 20-20, Item 5, Ref. 17)

6.4 Quantification of Other Operator Actions

6.4.1 Operator Actions Used in Systems Analysis

The following operator action quantifications are used in the Systems Analysis (Section 7.0) in combination with hardware failure.

1. $OP1_{CT}$ - Operator fails to initiate cooling tower operation, given unavailability of service water pumphouse or pumps. This action is used in top events WA and WB (service water train A and train B) in the Support Systems tree. See Section 7.4.2. This

action is only modeled when offsite power is available. It is assumed that time is available (15 to 30 min) following loss of a service water train before the operator must initiate the cooling tower to prevent overheating of PCC. Cooling tower initiation is not modeled for LOSP because of the immediate need for cooling the diesel generators.

- $OP1_{CT}$ = 1.3E-3 (mean)

  BE = 1.0E-3 (Table 20-12, Item 3, Ref. 17)

  EF = 3 (Table 20-12, Item 3, Ref. 17)

2. OP_{RR} - Operator fails to correctly start RHR pump or operator fails to align RHR train correctly. This action is used in top event RR in the Transient and LOCA trees; see Section 7.1.3.

   This action is essentially the same as OP_{RI} (in Section 6.3.1) and is quantified the same:

   Operator fails to correctly start the "operating" RHR train after tripping the pump due to low suction:

   - $OP1_{RR}$ = $OP1_{RI}$ = 4.0E-3 (mean)

   Operator fails to correctly start the standby RHR train, given failure of the operating train:

   - $OP2_{RR}$ = $OP2_{RI}$ = 1.3E-3 (mean)

3. $OP1_{FD}$ - Operator fails to rack in the charging and SI pumps to allow for feed and bleed cooling, given failure of the operating charging pump. This action is included in the feed portion of feed and bleed cooling which is included in the top event LC in the Transient and LOCA trees; see Section 7.5.4.

   - $OP1_{FD}$ = 6.3E-3 (mean)

     BE = 5.0E-3 (Table 20-12, Item 11, Ref. 17)

     EF = 3 (Table 20-12, Item 11, Ref. 17)

4. OP_{FB} - Operator fails to maintain adequate feed/bleed flow to remove decay heat and conserve inventory, including makeup to RWST. This action is included in the quantification of feed and bleed cooling which is part of top event LC in the Transient and LOCA trees; see Section 7.5.4.

o $OP1_{FB}$ = Operator fails to initiate feed and bleed or if the RWST is full, operator fails to ramp back charging flow or begin makeup to RWST or if RWST is empty, operator fails to begin makeup to boric acid storage tank.

$$\approx OP_S + RWST_{FULL} * (OP_{CF} * OP_{RT}) + RWST_{EMPTY} * OP_{BT}$$

$$\approx 1.7E-3 \text{ (mean)}$$

where:

$$RWST_{EMPTY} = 1 - RWST_{FULL} = \frac{1 \text{ week}}{10 \text{ yrs}}$$

$$= 0.002 \text{ (mean)}$$

based on assuming one week of maintenance every 10 years during which time the RWST is empty and unavailable to be refilled. This is assumed to vary between 4 weeks per 10 years (weight = 0.1) and one week every 40 years (weight = 0.1), with the best estimate one week in 10 years (weight = 0.8).

OP_S = Operator fails to correctly initiate feed and bleed cooling - start charging pump and open the RWST suction valve. Time available equals 30 min.

= Operator selects wrong switch (charging pump that is disabled) and fails to detect need for cooling (from incore thermocouples) or detects need for cooling but again selects wrong switch.

$$\approx 2 * OP1 * (NR + OP2)$$

$$= 5.8E-4 \text{ (mean)}$$

where

OP_S:OP1 = operator selects wrong switch

= 1.3E-3 (mean)

BE = 0.001 (Table 20-12, Item 3, Ref. 17)

EF = 3 (Table 20-12, Item 3, Ref. 17)

OP_S:OP2 = operator selects wrong switch, given he previously selected wrong switch (OP1). Moderate dependency assumed.

= 0.22 (mean)

BE = 0.14 (Table 20-18, Item 6, Ref. 17)

EF = 5 (Table 20-20, Item 5, Ref. 17)

OP_S:NR = operator fails to detect that core cooling has not been initiated; fails to detect incore thermocouple temperature continues to increase - check reading digital indicator.

= 1.3E-3 (mean)

BE = 0.001 (Table 20-11, Item 1, Ref. 17)

EF = 3 (Table 20-11, Item 1, Ref. 17)

OP_{CF} = operator fails to ramp back charging flow to conserve RWST inventory, given containment sump alarms; skips procedural step in response procedure. Time available equals 2 hours.

= 1.3E-2 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

OP_{RT} = operator fails to monitor RWST level and begin making up to RWST. Time available is greater than 6 hours. Operator fails to detect unannunciated deviant display on an analog meter without limit marks - assuming hourly scans.

= 4.8E-2 (mean)

BE = 0.03 (Table 20-25, Item 2(a) - (f), Ref. 17)

EF = 5 (Table 20-20, Item 5, Ref. 17)

OP_{BT} = operator fails monitor boric acid storage tank level (given RWST is empty) and begin making up to the tank. Time available equals:

$$\left(\frac{\text{20,000 gal in BAST}}{\text{400 gpm-one charging pump}}\right) = 50 \text{ min}$$

Operator fails to detect unannunciated deviant display on an analog meter without limit marks - BAST level - assuming initial audit only.

= 0.24 (mean)

BE = 0.15 (Table 20-25, Item 2(a), Ref. 17)

EF = 5 (Table 20-20, Item 5, Ref. 17)

Operator fails feed and bleed cooling function, given no support systems available. (Gravity feed, used only for RCS Condition X - RCS open):

o $OP2_{FB}$ = $RWST_{FULL} * (OP_{S'} + OP_C) + RWST_{EMPTY}$

= 1.8E-2 (mean)

where

$RWST_{EMPTY}$ = 1 - $RWST_{FULL}$ = 0.002 (above)

$OP_{S'}$ = operator fails to correctly initiate gravity feed - opening several valves assuming moderately high stress, dynamic action.

= $OP_S * F_S$

= 2.9E-3 (mean)

where OP_S = 5.8E-4 (from above)

F_S = 5 (Table 20-16, Item 6, Ref. 17)

OP_C = operator fails to control flow rate and drain RWST before 24 hours. Time available equals 6 hours. Operator skips a procedural step - long list, no checkoff provisions.

= 0.013

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

6.4.2 Containment Isolation Operator Actions

Operator actions to isolate containment in the event of a core damage event are combined with hardware unavailabilities in Section 10.1 (Table 10-3). These actions are quantified below:

1. OP_{EH} - operator fails to restore equipment hatch prior to core melt. This action is included in top event EH in the Transient and LOCA trees (see Table 10-3, footnote 9).

   This action to restore the hatch, without major error, takes between 4 hours and 8 hours, possibly even less in the case of an emergency, based on information from plant maintenance personnel. This action was assumed to be guaranteed failure for plant conditions with less than 8 hours available to core uncovery with loss of cooling - conservatively modeled as all LOCAs and all transients initiated with the RCS drained down (Condition X). For Condition W (RCS filled), it is assumed that the hatch can be restored unless an error is made in rigging. This error is quantified below:

o $OP1_{EH}$ = OP_{EH} given hardware/operator initiated transient with RCS Condition W (RCS filled). Time available equals

T = 15.5 hr (see OR1, Section 6.2.1) - 4 hr (time to respond to transient event)

= 11.5 hr

Crane operator omits critical step in rigging hatch and checker fails to detect error.

= OP1 * NR

= 1.3E-2 (mean)

where

OP1 = crane operator omits step, written procedures available but not used - "second nature" action. Moderately high stress, step-by-step action assumed.

= 0.16 (mean)

BE = 0.05 (Table 20-7, Item 5, Ref. 17)

EF = 5 (Table 20-7, Item 5, Ref. 17)

F_S = stress factor

= 2 (Table 20-16, Item 4, Ref. 17)

NR = checker fails to detect error prior to irrecoverable action - special short term, one-of-a-kind checking with alerting factors.

= 0.08 (mean)

BE = 0.05 (Table 20-22, Item 3, Ref. 17)

EF = 5 (Table 20-22, Item 3, Ref. 17)

o $OP2_{EH}$ = OP_{EH} given internal/external hazard initiated transients with no LOSP or recoverable LOSP. Time available equals

T = 15.5 hr (see OR1, Section 6.2.1) - 4 hr (time to respnd to hazard) - 4 hr (time to respond to transient) = 7.5 hr

= OP2 * NR

= 3.2E-2 (mean)

where

OP2 = OP1 (above) with extremely high stress level due to the reduced time available.

= 0.40 (mean)

BE = 0.05 (Table 20-7, Item 5, Ref. 17)

EF = 5 (Table 20-7, Item 5, Ref. 17)

F_S = 5 (Table 20-16, Item 6, Ref. 17)

NR = 0.08 (mean) - (same as NR above)

2. $OP1_{PL}$ - operator fails to close the containment online purge (COP) and containment air purge (CAP) valves prior to core melt. The action is included in top event EH in the Transient and LOCA trees (see Table 10-3, footnote 11).

o OP_{PL} = OP_{PL} given transient with RCS Conditions W or Y (RCS filled). Time available equals 11.5 hr (from $OP1_{EH}$ above).

= OP1 * NR

= 2.0E-3 (mean)

where

OP1 = operator skips procedural step to close CAPs/COPs; long list, no checkoff provisions. Moderately high stress assumed.

= 0.025 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

F_S = stress factor = 2

(Table 20-16, Item 4, Ref. 17)

NR = operator fails to recover from OP1 and close valves given alert - stack radiation alarms.

= 0.08 (mean)

BE = 0.05 (Table 20-22, Item 3, Ref. 17)

EF = 5 (Table 20-22, Item 3, Ref. 17)

o $OP2_{PL}$ = OP_{PL} given transient with RCS Condition X (drained down) or LOCA. Time available equals T = 3 hr (see OR2 in Section 6.2.1)

= OR2 * NR

= 5.0E-3 (mean)

where

OP2 = OP1 (above) with very high stress level due to reduced time available.

= 0.063 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

F_S = 5 (Table 20-16, Item 6, Ref. 17)

NR = 0.08 (mean) - (same as NR above)

3. OP_{SP} - Operator fails to close all small containment penetrations prior to core melt, given large penetrations (equipment hatch, COPs, CAPs) are isolated. This action is included in top event SA in Transient and LOCA trees.

o $OP1_{SP}$ = OP_{SA} given RCS Condition W or Y (filled). Time available equals 11.5 hr (see $OP1_{PL}$ above).

= OP_{CR} + 2 * OP_{OUT}

= 1.7E-2 (mean)

where

OP_{CR} = operator fails to close valves that can be isolated from the control room.

$= 2.0E-3$ (mean) - (from $OP1_{PL}$ above)

OP_{OUT} = operator fails to close valves that must be locally isolated. Moderately high stress level for a step-by-step action is assumed. It is also assumed that two penetrations must be locally isolated.

$= 7.5E-3$ (mean)

BE = 3.0E-3 (Table 20-13, Item 2, Ref. 17)

EF = 3 (Table 20-13, Item 2, Ref. 17)

F_S = 2 (Table 20-16, Item 4, Ref. 17)

o $OP2_{SP}$ = OP_{SA} given RCS Condition X (drained). Time available equals 3 hr (see $OP2_{PL}$ above).

$= OP_{CR} + 2 * OP'_{OUT}$

$= 4.0E-2$ (mean)

where

OP_{CR} = 2.0E-3 (mean) - (above)

OP'_{OUT} = OP_{OUT} from above with very high stress.

$= 1.9E-2$ (mean)

BE = 3.0E-3 (Table 20-13, Item 2, Ref. 17)

EF = 3 (Table 20-13, Item 2, Ref. 17)

F_S = 5 (Table 20-16, Item 5, Ref. 17)

6.4.3 Operator Actions Resulting in or Contributing to an Initiating Event

1. Valve RH-V33 is a manual valve on the path connecting the RHR pump discharge to the RWST. This valve is opened when draining the refueling cavity water back to the RWST. If this valve is not closed after the refueling cavity is drained, this can be a potential LOCA source during the next outage when RHR is initiated. This LOCA (L3) would occur early in an outage when decay heat level is relatively high and the primary system is still hot. In order for

this event to occur, multiple independent operator errors must occur, as follows:

o OP_{L3} = $(OP_1 + OP_2) * OP_3 * OP_4$

= 3.9E-6 per year

where

OP_1 = operator skips procedural step to close RH-V33

= 0.013 (mean)

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

OP_2 = AO fails to close correct valve, given correct instructions from operator (unclearly labeled)

= 0.01 (mean)

BE = 0.008 (Table 20-13, Item 4, Ref. 17)

EF = 3 (Table 20-13, Item 4, Ref. 17)

OP_3 = independent check for mode change fails to identify RH-V33 open (position indicator difficult to read)

= 0.013 (mean)

BE = 0.01 (Table 20-14, Item 4, Ref. 17)

EF = 3 (Table 20-14, Item 4, Ref. 17)

OP_4 = when RHR is started in subsequent outage, operator fails to close RH-V21 or V22 prior to RHR initiation - operator skips procedural step.

= 0.013

BE = 0.01 (Table 20-7, Item 4, Ref. 17)

EF = 3 (Table 20-7, Item 4, Ref. 17)

2. For LOCA LS, loss of coolant to the containment sump (see Section 7.6.3) the operator action is quantified for failure to immediately reclose the sump valve during the valve test with an undetected

check valve failure. The operator is expected to detect a plant upset condition and immediately reset his previous action - i.e., opening the valve. It is not necessary for him to detect the cause of the upset condition to be successful for this action. This action is quantified as a special short term, one-of-a-kind checking with alerting factors.

o NR_{LS} = 0.08 (mean)

median = 0.05 (Table 20-22, Item 3, Ref. 17)

EF = 5 (Table 20-22, Item 3, Ref. 17)

3. In response to a control room fire with results in loss of AC power, the operators must go to the Remote Safe Shutdown Panel and other local breaker controls to continue decay heat removal. The action is quantified as a diagnosis function with time available equal 60 min, and dynamic action with moderately high stress (F_S).

$F_{HE',2}$ = Operator fails to diagnose, given 60 min.

= 4.3E-3 (mean)

BE = 1.0E-4 (Ref. 17, Table 20-3, Item 5)

EF = 30 (Ref. 17, Table 20-3, Item 5)

F_S = 5 (Ref. 17, Table 20-16, Item 5)

This operator action is used in the quantification of initiating event FCRAC in Section 8.2.1.3.

TABLE 6-1

SUMMARY OF OPERATOR ACTIONS FOR TRANSIENT TREE

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
Short Term						
OC	OP_{OC}	Operator fails to control the source of overpressurization.	9.5E-4	1.6E-5	1.9E-4	3.4E-3
(a) TP	$OP1_{TP}$	Operator fails to trip vortexing or cavitating RHR pump, given no overpressure condition.	3.7E-4	2.6E-5	1.7E-4	1.3E-3
	$OP2_{TP}$	Operator fails to trip cavitating RHR pump, given overpressure condition.	1.7E-3	2.5E-4	1.1E-3	5.2E-3
Long Term						
(b) OR	OR1	Operator fails to choose a viable heat removal mode, given loss of RHR with the RCS full.	1.7E-5	6.6E-8	2.0E-6	6.0E-5
	OR2	Operator fails to choose a viable heat removal mode, given RCS is drained, operating RHR pump is failed (hardware) or pump failed from vortexing.	1.7E-4	6.7E-7	2.0E-5	6.0E-4
	OR3	OR2 except operating RHR pump is vortexing and successfully tripped (TP).	1.7E-4	6.7E-7	2.0E-5	6.0E-4
	OR4	OR2 except standby RHR pump is also unavailable.	4.3E-4	1.7E-6	5.0E-5	1.5E-3
	OR5	OR2 with no support system available.	1.7E-3	6.6E-6	2.0E-4	6.0E-3

(a) $OP2_{TP}$ quantified assuming prevortexing level alarm.

(b) OR quantified assuming accident response procedures and administrative controls to assure either either secondary cooling or gravity RWST feed options available.

TABLE 6-2

SUMMARY OF OPERATOR ACTIONS FOR LOCA TREE

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
Short Term						
OD	OD1	Operator fails to detect LOCA prior to substantial inventory loss for LOCA L1, L5, L6, and LS.	1.6E-3	6.0E-5	6.0E-4	6.0E-3
	OD2	OD1 except for L3.	2.7E-4	1.0E-5	1.0E-4	1.0E-3
	OD3	OD1 except for LP.	1.6E-3	2.0E-4	1.0E-3	5.0E-3
IR	$OP1_{IR}$	Operator fails to isolate the RHR suction valves, given he detected the LOCA, for L1 and LP.	3.8E-3	1.0E-3	3.0E-3	9.0E-3
	$OP2_{IR}$	$OP1_{IR}$ for L3.	2.7E-4	1.0E-5	1.0E-4	1.0E-3
(a) TP	OP_{TPA}	Operator fails to trip cavitating RHR pump, given LOCA's L1 or LP and operator isolates leak (IR).	1.0E-4	1.5E-6	2.6E-5	4.4E-4
	OP_{TPB}	OP_{TPA} except given operator fails to isolate leak $(\overline{IR})$ and fails to initiate makeup $(\overline{MU})$.	2.2E-1	2.8E-2	1.4E-1	7.0E-1
Long Term						
(b) OL		Operator fails to determine appropriate actions to restore decay heat removal before core damage occurs.				
	OL1	OL given LOCA's L1 or LP with operator successfully isolating RHR (IR).	5.0E-5	2.0E-7	6.0E-6	1.8E-4
	OL2	OL given LOCA's L5 or L6 with at least one support train available.	2.6E-4	1.0E-6	3.0E-5	9.0E-4

TABLE 6-2

SUMMARY OF OPERATOR ACTIONS FOR LOCA TREE

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
OL	OL3	OL [illegible] LOCA's L5 or L6 with no support train[illegible]ailable.	6.5E-4	2.5E-6	7.5E-5	2.3E-3
	OL4	OL given LOCA L3 with operator successfully isolating RHR (IR).	6.5E-5	2.5E-7	7.5E-6	2.3E-4
	OL5	OL given LOCA L5 with at least one support train available.	8.5E-4	3.3E-6	1.0E-4	3.[illegible]E-3
	OL6	OL given LOCA's L1 or LP with RHR not isolated (IR).	4.3E-4	1.7E-6	5.0E-5	1.5E-3
	OL7	OL given OD failed.	9.5E-4	4.0E-6	1.2E-4	3.6E-3

NOTES:

(a) OP_{TP} quantified assuming prevortexing alarm.

(b) OL quantified assuming accident response procedures.

TABLE 6-3

SUMMARY OF OPERATOR ACTIONS FOR PROCEDURE EVENT TREES

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
Tree 1						
RV	$OP1_{RV}$	Operator attempts to open both RHR suction valves to one train with RCS presrure greater than 450 psig.	3.8E-3	1.0E-3	3.0E-3	9.0E-3
	$OP3_{RV}$	Operator fails to detect pressure transmitter failure.	4.5E-2	5.6E-2	2.8E-2	1.4E-1
(a) CT	$OP1_{CT}$	Operator fails to implement cross-train power alignment for RHR suction valves.	1.7E-2	5.0E-3	1.4E-2	3.7E-2
RI	$OP1_{RI}$	Operator fails to correctly start the first RHR pump train.	4.0E-3	3.4E-4	2.1E-3	1.4E-2
	$OP2_{RI}$	Operator fails to correctly start the second RHR pump train given the first pump failed.	1.3E-3	1.1E-4	7.0E-4	4.5E-3
SA	$OP1_{SA}$	Operator fails to remove power from valves during test or maintenance of RHR suction valves given CT successful, for Case C only.	8.3E-3	5.6E-4	4.0E-3	2.8E-2
	$OP2_{SA}$	$OP1_{SA}$ except CT failed, for Case C only.	1.1E-1	5.8E-3	4.6E-2	4.2E-1
NC	$NR1_{NC}$	Operator fails to recover from inadvertent SI before overpressurization.	2.7E-1	1.0E-2	1.0E-1	9.9E-1
	$NR2_{NC}$	Operator fails to recove rom letdown isolation before overpressurization.	1.1E-1	1.4E-2	7.0E-2	3.5E-1
	$NR3_{NC}$	Operator fails to recover from maximum makeup before overpressurization.	2.4E-1	3.0E-2	1.5E-1	7.5E-1

TABLE 6-3

SUMMARY OF OPERATOR ACTIONS FOR PROCEDURE EVENT TREES

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
Tree 2						
(b) TV	OP_{TV}	Operator fails to install temporary level transmitter correctly.	1.0E-3	7.1E-5	5.0E-4	3.6E-3
DR	$OP1_{DR}$	Operator fails to reduce flow to 1000 gpm given Case B.	3.1E-3	2.1E-4	1.5E-3	1.1E-2
(c) LM	$OP1_{LM}$	Operator fails to maintain level given Case B.	8.6E-4	5.9E-5	4.1E-4	2.9E-3
	$OP2_{LM}$	Operator fails to maintain level given Case C.	3.1E-4	2.1E-5	1.5E-4	1.1E-3
(d) VA	OP_{VA}	Operator fails to vent RCS to atmosphere.	0.0	------	------	------
(e) SA	$OP3_{SA}$	Operator fails to control level given Case B.	2.2E-2	1.6E-3	1.1E-2	7.9E-2
	$OP4_{SA}$	Operator fails to control level given Case C.	3.9E-4	2.8E-5	2.0E-4	1.5E-3
Tree 3						
DF	OP_{DF}	Operator fails to close refueling pool drain valve.	2.1E-5	1.5E-6	1.0E-5	7.2E-5
CS	OP_{CS}	Cavity seal is not installed correctly.	1.7E-4	1.1E-5	1.0E-4	9.2E-4
Tree 4						
(f) CD	OP_{CD}	Operator fails to close RH-V21 or RH-V33 valves in the RWST refilling path.	3.1E-3	2.2E-4	1.5E-3	1.1E-2
(f) BR	OP_{BR}	Operator fails to realign RHR train B for cooling.	1.3E-2	3.3E-3	1.0E-2	3.0E-2
RF	OP_{RF}	Operator fails to reduce RHR flow to 1000 gpm.	3.1E-3	2.3E-4	1.7E-3	1.2E-2

TABLE 6-3

SUMMARY OF OPERATOR ACTIONS FOR PROCEDURE EVENT TREES

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
Tree 4						
(c) LM	$OP3_{LM}$	Operator fails to achieve desired level, given level is at the mid-plane of the hot leg nozzle.	8.6E-4	5.9E-5	4.1E-4	2.9E-3
	$OP4_{LM}$	Operator fails to achieve desired level, given level is at the top of the flange.	3.1E-4	2.1E-5	1.5E-4	1.1E-3
(e) SA	$OP6_{SA}$	Operator fails to maintain level at hot leg nozzle mid-plane.	3.3E-2	4.0E-3	1.7E-2	1.2E-1
	$OP7_{SA}$	Operator fails to maintain level at vessel flange.	1.2E-2	8.3E-4	5.9E-3	4.4E-2
Tree 5						
(b) TL	OP_{TL}	Temporary level transmitter indication not aligned for operation.	1.3E-2	3.3E-3	1.0E-2	3.0E-2
	$OP2_{CT}$	Operator fails to ensure cross-train power alignment for RHR suction valves.	7.4E-3	4.4E-4	3.3E-3	2.8E-2
LM	$OP5_{LM}$	Operator fails to maintain level at 45', given Case B.	2.2E-3	2.0E-4	1.2E-3	7.3E-3
	$OP6_{LM}$	Operator fails to maintain level at 45', given Case C.	3.4E-3	3.0E-4	1.8E-3	1.1E-2
CC	$OP1_{CC}$	Operator fails to correctly cross-calibrate LI-462 (pressurizer level) with tygon tube.	2.9E-2	8.7E-3	2.3E-2	6.6E-2
LT	$OP4_{LT}$ & $OP5_{LT}$	Operator fails to restore PT-403 and PT-405 to service.	4.7E-3	1.1E-3	3.6E-3	1.1E-2

TABLE 6-3

SUMMARY OF OPERATOR ACTIONS FOR PROCEDURE EVENT TREES

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
Tree 5						
PU	$OP1_{PU}$ & $OP2_{PU}$	Operator fails to maintain pressurizer level.	3.9E-3	1.0E-3	3.0E-3	9.0E-3
Tree 6						
LI	$OP1_{LI}$	Operator fails to control excess letdown during heatup, given Cases A or B.	9.0E-4	5.7E-5	4.3E-4	3.2E-3
	$OP2_{LI}$	$OP1_{LI}$ except Case C.	2.3E-3	1.4E-4	1.1E-3	9.0E-3
IS	OP_{IS}	Operator fails to isolate RHR.	3.1E-3	2.1E-4	1.5E-3	1.1E-2

NOTES:

(a) OP_{CT} - quantification assumes procedural enhancement to verify cross-train alignment on both trains.

(b) OP_{TV} and OP_{TL} are modeled with the temporary level transmitter (assuming the tygon tube will not be used).

(c) OP_{LM} - quantification assumes prevortexing level alarm at hot leg mid-plane.

(d) OP_{VA} - is assumed to not be a failure mode based on delta-P sensing level monitor.

(e) OP_{SA} - quantification assumes prevortexing alarm.

(f) OP_{CD} and OP_{CR} are based on procedural enhancement to drain to flange and then close V33.

TABLE 6-4

SUMMARY OF OPERATOR ACTIONS FOR SYSTEMS ANALYSIS AND CONTAINMENT ISOLATION

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
Short Term						
WA,WB	$OP1_{CT}$	Operator fails to initiate cooling tower operation, given unavailability of service water pump (Support Systems tree).	1.3E-3	3.3E-4	1.0E-3	3.0E-3
Long Term						
RR	$OP1_{RR}$	Operator fails to restart operating RHR train after tripping pump on low suction (Transient, LOCA trees).	4.0E-3	3.4E-4	2.1E-3	1.4E-2
	$OP2_{RR}$	Operator fails to correctly start second RHR train given failure of first train (Transient, LOCA trees).	1.3E-3	1.1E-4	7.0E-4	4.5E-3
LC	$OP1_{FD}$	Operator fails to rack in charging/SI pumps to allow for feed and bleed cooling (Transient, LOCA trees).	6.3E-3	1.7E-3	5.0E-3	1.5E-2
	$OP1_{FB}$	Operator fails to maintain feed and bleed cooling function, given at least one train of support systems available (Transient, LOCA trees).	1.7E-3	3.8E-4	1.3E-3	4.8E-3
	$OP2_{FB}$	Operator fails to maintain feed and bleed cooling function, given no support systems available (Transient, LOCA trees).	1.8E-2	6.6E-3	1.5E-2	3.8E-2
(a) EH	$OP1_{EH}$	Operator fails to restore equipment hatch, given hardware/operator initiated transient with RCS Condition W (Transient, LOCA trees).	1.3E-2	5.1E-4	5.0E-3	5.0E-2

TABLE 6-4

SUMMARY OF OPERATOR ACTIONS FOR SYSTEMS ANALYSIS AND CONTAINMENT ISOLATION

Top Event	Operator Action	Description	Mean Value	Failure Frequency 5th Percentile	50th Percentile	95th Percentile
(a) EH	$OP2_{EH}$	Operator fails to restore equipment hatch, given internal/external initiated transient with offsite power available or recoverable (Transient, LOCA trees).	3.2E-2	1.3E-3	1.3E-2	1.2E-1
	$OP1_{PL}$	Operator fails to close COP and CAP valves, given RCS Conditions W or Y (Transient, LOCA trees).	2.0E-3	1.4E-4	1.0E-3	7.2E-3
	$OP2_{PL}$	Operator fails to close COP and CAP valves, given RCS Condition X or LOCA (Transient, LOCA trees).	5.0E-3	3.6E-4	2.5E-3	1.8E-2
SP	$OP1_{SP}$	Operator fails to close all small containment penetrations for RCS Condition W or Y (Transient, LOCA trees).	1.7E-2	5.1E-3	1.4E-2	3.9E-2
	$OP2_{SP}$	Operator fails to close all small containment penetrations for RCS Condition X (Transient, LOCA trees).	4.0E-2	1.1E-2	3.2E-2	9.2E-2
Initiating Event						
L3	OP_{L3}	Operator fails to close RH-V33 and subsequent checks fail to detect error; results in LOCA back to RWST.	3.9E-6	3.5E-7	1.9E-6	1.1E-5
LS	NR_{LS}	Operator fails to reclose sump valve during the valve test with an undetected check valve failure; results in a LOCA to the sump.	8.0E-2	1.0E-2	5.0E-2	2.5E-4
FCRAC	$F'_{HE,2}$	Operator fails to control decay heat removal from the remote safe shutdown panel, given fire in the control room resulting in loss of AC power and 2 hours before core damage.	4.3E-3	1.7E-5	5.0E-4	1.5E-2

NOTE:
(a) OP_{EH} quantification assumes administrative controls given in Section 10.1.

7.0 SYSTEM ANALYSIS

This section documents the systems analysis used to quantify initiating events and hardware (non-operator action) portions of event tree top events. The initiating events are part of the plant model described in Section 3 and quantified in Section 5. The event tree top events are also an integral part of the plant model as well as the procedure-initiated event model. The quantification of top events is documented in Section 5 which uses the results of this section as input. The quantitative results of this section are summarized in Tables 7-1 through 7-4.

7.1 Residual Heat Removal (RHR)

7.1.1 System Description (SSPSA Section D.8)

The RHR system is used for long term primary system cooling after shutdown. In this mode, the system transfers heat from the reactor coolant system to the Primary Component Cooling Water (PCC) system by taking suction from the hot legs of two reactor coolant loops, through two . . pumps and heat exchangers, and discharging to the cold legs of each loop.

The heat is ultimately removed to the environment through the Service Water (SW) system which cools the PCC heat exchangers. The PCC system is also needed to cool the RHR pump seals and to cool the room ventilation air coolers. PCC and SW systems are analyzed in Sections 7.3 and 7.4, respectively.

One RHR train consisting of an RHR pump, heat exchanger, and flow path to at least two cold legs is needed to assure successful shutdown cooling. The room ventilation (the Enclosure Air Handling system) function is highly reliable because of its configuration; redundant fans and and air coolers either of which cool both trains of RHR (SSPSA Appendix D.7). Loss of ventilation can be mitigated by use of portable fans and open doors while repairs are being made, so loss of ventilation is not included in the quantification.

The simplified system P&ID is given in Figure 7-1 for RHR Train A (Train B is symmetric). A block diagram for this system is shown in Figure 7-2. The components included in each block in Train A in the block diagram are listed in Table 7-5. Train B blocks are symmetrical with Train A. (See SSPSA Section D.8 for development of the system failure logic).

The logic expression for a single train failure is:

$$RHR_A = C + HA + E + G + H$$

As noted in Table 7-5, bloc LTA and K are not included in the model because their failures are included explicitly in top events in the procedure initiated event trees.

The logic expression for the system failure is:

$$RHR_{AB} = RHR_A * RHR_A$$

where RHR_A is the single train logic expression described above.

The independent hardware unavailability can be quantified using the logic expression and the failure data for the components in each block l ed . Table 7-5.

For a single train failure to start,

$$RH1_S = P8A_S + MOV145_{OPEN}$$

$$= 6.65E-3$$

$P8A_S$ = Pump 8A (RHR Train A) fails to start

= Z1PMOS (Table 9-1)

$= 2.35E-3$

$MOV145_{OPEN}$ = PCC heat exchanger MOV fails to open on demand

= ZIVMOD (Table 9-1)

$= 4.30E-3$

For a single train failure to run,

$RH1_R = Q_C + Q_{HA} + Q_E + Q_G + Q_H$

$= 3.89E-5/hr$

where:

$Q_C = P8A_R + HX_{EL} + 4MV_{TC} + CV_{TC} + AOV_{TC}$

$Q_{HA} = MV_{TC} + MOV_{TC}$

$Q_E = MOV_{TC}$

$Q_G = Q_H = MV_{TC} + 2\ CV_{TC}$

These blocks are quantified using the following data variables (means).

$P8A_R$ = Pump 8A (RHR Train A) fails to start

= ZIPMOR

$= 3.36E-5/hr$

HX_{EL} = HX (excessive leakage) = ZIHXRB

$= 1.95E-6/hr$

MOV_{TC} = MOV (transfer closed) = ZIVMOT

$= 9.27E-8/hr$

AOV_{TC} = AOV (transfer closed) = ZIVAOT

$= 2.67E-7/hr$

CV_{TC} = CV (transfer closed) = ZIVCOL

$= 5.36E-7/hr$

MV_{TC} = MV (transfer closed) = ZIVHOT

$= 4.2E-8/hr$

These data variables are from Table 9-1.

Common cause hardware unavailability for the RHR system is quantified for failure to start and failure to run, as follows.

$RHCC_S = RH1_S * BETA_S$

$= P8A_S * BETA1_S + MOV145_{OPEN} * BETA2_S = 3.39E-4$ (mean)

where:

$P8A_S$ = RHR pump fail to start = 2.35E-3

$MOV145_{OPEN}$ = RHR Hx PCC MOV fail to open on mand

= 4.3E-3

$BETA1_S$ = Common cause beta factor for RH pumps failure to start

= ZBPDHS (Table 9-2)

= 6.68E-2

$BETA2_S$ = Common cause beta factor for MOV fail to open

= ZBVMOD (Table 9-2)

= 4.23E-2

The common cause "failure to run" term is given by:

$RHCC_R = P_R * T_M * BETA_R$

$= 9.27E-6 * T_M$

where:

P_R = RHR pump fa.l to run failure rate

= ZIPMOR (Table 9-1)

= 3.36E-5

T_M = mission time

$BETA_R$ = common cause beta factor RHR pumps failure to run

= ZBPDHR (Table 9-2)

= 0.276

These hardware unavailability terms are combined in the following sections for the various boundary conditions of the RHR system and maintenance is included as appropriate. The RHR system is modeled in the Procedural Event Trees to identify and quantify loss of RHR initiating events. RHR is modeled in the plant response trees (Shutdown Transient Tree and Shutdown LOCA Tree) to operate if plant conditions allow. These models are quantified below. The model assumes that Train A of RHR (and therefore its support systems) is normally operating and Train B is in standby.

7.1.2 Loss of RHR Initiating Events (Procedural Tree Top Events)

The RHR system is modeled in the Procedural Event Trees in top event RI (RHR initiated) in tree 1 and top event RM (RHR maintained) in all trees 1 through 6. Possible outcomes of the Procedural Event Trees include initiating events to the Shutdown Transient Trees involving loss of the operating RHR pump. The top events are quantified using the following assumptions:

- Only the operating RHR pump is modeled in top event RM. If it fails to continue to operate, it is assumed the plant will be in a transient condition requiring the operators to start the standby pump, if available, or to use alternate cooling methods.
- Top event RI includes failure of both RHR pump trains to start. When the RHR pumps are first started in tree 1, decay heat removal is occurring via the steam generators. Failure of the first pump to start is not considered a transient. If both pumps fail to start, it is assumed that the plant is in a mild transient for 24 hours while the RHR pumps are restored.
- Both RHR trains are assumed operable at the beginning of each procedural tree except for the following:
  - (1) when the standby RHR train is in planned maintenance, which can occur in trees 1, 5, and 6, or

(2) when the standby RHR train is not restored to operable following refueling drain (top event BR in tree 4 failed), which can occur in trees 5 and 6.

This is consistent with the Technical Specifications which require two operable RHR trains when drained down. It is assumed that the RHR system is restored to complete operability before plant evolutions proceed.

- o All RHR support systems and offsite power are assumed available throughout the procedural trees. Loss of support trains and offsite power are handled separately as initiating events.
- o RHR Train A is assumed to be running and Train B in standby or in maintenance. This modeling assumption is consistently used with the support systems.

Top event RI includes failure of either RHR pump train to start on demand (manual start). The quantification of RI is:

$$RI1 = [RH1_S + OP1]_A * [RH1_S + OP2]_B + RHCC_S$$

$$= 4.24E-4 \text{ (mean)}$$

where:

$RH1_S$ = RHR Train A (B) fails to start (from Section 7.1.1)

= 6.65E-3

$OP1_{RI}$ = Operator fails to start first RHR train

= 4.0E-3 (from Section 6.3.1)

$OP2_{RI}$ = Operator fails to start opposite RHR train given the first pump failed

= 1.3E-3 (from Section 6.3.1)

$RHCC_S$ = Common cause unavailability of RHR pumps to start or MOVs to open

= 3.39E-4 (above)

Top event RM includes the operating RHR pump train failing to continuously operate for the mission time in each Procedural Event Tree. Maintenance occurs only on the standby pump, so the quantification of

RM does not include maintenance unavailability. The unavailability of the operating RHR train is:

$$\overline{RM} = RH1_R * T_M$$

where:

$RH1_R$ = RHR single train fails to run

= 3.89E-5/hr (from Section 7.1.1)

T_M = Mission Time in each Procedural Event Tree (Table 9-3).

Top event RM is quantified for each tree and case as follows. The mission times are derived in Section 9.2.

RM1	= $\overline{RM}$ | Case A, Tree 1	(T_M = 295 hr)	= 1.1E-2
RM2	= $\overline{RM}$ | Case B, Tree 1	(T_M = 31 hr)	= 1.2E-3
RM3	= $\overline{RM}$ | Case C, Tree 1	(T_M = 50 hr)	= 1.9E-3
RM4	= $\overline{RM}$ | Case B, Tree 2	(T_M = 959 hr)	= 3.7E-2
RM5	= $\overline{RM}$ | Case C, Tree 2	(T_M = 47 hr)	= 1.8E-3
RM6	= $\overline{RM}$ | Case C, Tree 3	(T_M = 161 hr)	= 6.3E-3
RM7	= $\overline{RM}$ | Case C, Tree 4	(T_M = 1440 hr)	= 5.6E-2
RM8	= $\overline{RM}$ | Case B, Tree 5	(T_M = 101 hr)	= 3.9E-3
RM9	= $\overline{RM}$ | Case C, Tree 5	(T_M = 193 hr)	= 7.5E-3
RMA	= $\overline{RM}$ | Case A, Tree 6 or Case B, Tree 6	(T_M = 24 hr)	= 9.3E-4
RMB	= $\overline{RM}$ | Case C, Tree 6	(T_M = 72 hr)	= 2.8E-3

7.1.3 RHR Top Events

The RHR system is modeled in the Shutdown Transient Tree and the Shutdown LOCA Tree in top event RR, normal RHR shutdown cooling recovered. This top event includes the hardware start and run for 24 hours for the preferred pump and/or the standby pump, as available. RR also included operator action to restart pumps if tripped (due to pump manually tripped in top event TP or due to LOSP) or if in standby (for the second pump). It is assumed that prior to the initiating event, Train A of RHR was operating and Train B was in standby, operable, or in maintenance. This assumption is used consistently for the support systems Train A and B.

Maintenance contribution is considered only on the standby train. Unplanned maintenance would be due to a failure in the operating pump which results in an initiating event - loss of operating RHR. It is assumed that planned maintenance is performed in accordance with Technical Specifications (see Appendix C). These specifications require two RHR loops or one RHR loop and two steam generators to be operable when the reactor coolant loops are filled in Modes 4 and 5. Two RHR loops must be operable when the loops are drained in Mode 5 and when less than 23 feet in Mode 6. During refueling (Mode 6) when the water level is 23 feet above the vessel flange (refueling cavity filled), one RHR loop is required to be operable.

Planned maintenance on an RHR loop can occur only when the coolant loops are filled and steam generators are operable or with the refueling cavity filled. These plant conditions occur in all the Procedural Event Trees except Tree 2 "RCS Drain" (for Case B) and Tree 4 "Reactor Cavity Drain" (for Case C). Trees 2 and 4 include plant evolutions to drain down the primary system which requires both RHR trains operable. Also, it is assumed that maintenance does not occur during actual refueling (Tree 3, Case C) because of the short duration of refueling (134 hours/year from Table 9-3). Maintenance unavailability is modeled in the other trees, where the RCS is filled and closed. This RCS condition is designator W described in Section 4.3.1.

Planned maintenance is assumed to occur once per year and to require between 2 and 10 days outage time (best estimate = 7 days) for each train. The duration is assumed to be distributed in a three bin histogram as follows:

DUR_1 = 2 days, WT_1 = 0.1

DUR_2 = 7 days, WT_2 = 0.8

DUR_3 = 10 days, WT_3 = 0.1

The maintenance contribution to single train unavailability is:

RHI_M = MAINT|RCS Filled (W)

= DUR * FREQ

= 0.112 (mean)

where:

DUR = mean duration of maintenance

= (48 hr) * 0.1 + (168) + 0.8 + (240) * 0.1

= 163 hours

FREQ = frequency of maintenance

= one planned maintenance per year while in RCS Condition W

$$= \frac{(1 \text{ maintenance})}{(\text{year})} * \frac{(1 \text{ year})}{(t_W)}$$

= 6.9E-4 per hour

where:

t_W = annual average time in RCS Condition

= 1455 hours per year (Section 9.2)

No planned maintenance is assumed to occur when the RCS is drained (X), i.e., Case B, Tree 2 and Case C, Tree 4 and when the RCS is full for refueling (Y), i.e., Case C, Tree 3. Thus,

MAINT|RCS Drained (X) or RCS Refueling (Y) = 0.0

As shown in Table 7- ., top event RR is quantifi:d for a number f boundary conditions that account for initiating event impacts and failures of support :ystems. These boundary conditions l:ad to the following unavailability expressions:

- o All Support Systems Available and RHR Trains A and B Available, RCS Filled (W)

  $RR1 = RHA_R * (RHB_S + RHB_R + RHB_M) + RHCC_R = 4.40E-4$ (mean)

- o All Support Systems Available and RHR Trains A and B Available, RCS Drained (X) ($RHB_M = 0.0$)

  $RR2 = RHA_R * (RHB_S + RHB_R) + RHCC_R = 2.30E-4$ (mean)

- o Loss of Train A of Support System and/or Train A RHR, RCS Filled (W)

  $RR3 = RHB_S + RHB_R + RH1_M = 0.121$ (mean)

- o Loss of Train A of Support Systems and/or Train A RHR, RCS Drained (X); ($RHB_M = 0.0$)

  $RR4 = RHB_S + RHB_R = 8.88E-3$ (mean)

- o Loss of Train B of Support Systems and/or Train B RHR (no dependence on RCS Condition because the B train is unavailable)

  $RR5 = RHA_R = 9.34E-4$ (mean)

- o LOSP and All Support Systems Available and RHR Trains A and B Available, RCS Filled (W); RCS Drained (X)

  $RR6 = (RH1_S + RHA_R) * (RHB_S + RHB_R + RHB_M) + RHCC_S + RHCC_R = 2.32E-3$ (mean)

  $RRZ = (RH1_S + RHA_R) * (RHB_S + RHB_R) + RHCC_S + RHCC_R$

  $= 6.28E-4$

- o LOSP and Loss of Train A or Support Systems and/or Train A RHR, RCS Filled (W); RCS Drained (X)

  $RR7 = RR3 = 0.121$

  RRY = F . = 8.88E-3

- LOSP and Loss of Train B of Support Systems and/or Train B RHR, RCS Filled (W) or RCS Drained (X)

  $RR8 = RH1_S + RHA_R = 7.58E-3$

- All Support Systems Available, RHR Trains A and B Available, RHR Pump A Tripped (TP), RCS Filled (W)

  $RR9 = (RHA_S + RHA_R) * (RHB_S + RHB_R + RHB_M) + RHCC_S + RHCC_R$

  $= 3.27E-3$

- All Support Systems Available, RHR Trains A and B Available, RHR Pump A Tripped (TP), RCS Drained (X) ($RHB_M = 0.0$)

  $RRA = (RHA_S + RHA_R) * (RHB_S + RHB_R) + RHCC_S + RHCC_R$

  $= 6.64E-4$

- Loss of Opposite Trains of Support Systems and RHR or Loss of Both Trains of Support Systems or Loss of Both RHR Trains

  $RRF = 1.0$

Based on the systems analysis in Section 7.1.1, the variables in these unavailability expressions are quantified as follows:

$RH1_S$ = The operating RHR train fails to automatically restart following LOSP

$= 6.65E-3$

RHA_S = The operating RHR train fails to start after being tripped (top event TP).

$= RH1_S + OP1_{RR} = 1.07E-2$

where $OP1_{RR} = 4.0E-3$ (from Section 6.4.1)

RHB_S = The standby RHR train fails to start given failure of Train A

$= RH1_S + OP2_{RR} = 7.95E-3$

where $OP2_{RR} = 1.3E-3$ (from Section 6.4.1)

RHA_R = The operating RHR train fails to continue to run for $T_M = 24$ hr

$= RH1_R * T_M = 3.89E-5/hr * 24\ hr = 9.34E-4$

RHB_R = The standby RHR train fails to run for T_M = 24 hr given successful start

= $RH1_R * T_M$ = 9.34E-4

$RHCC_S$ = Both RHR trains fail to start following a LOSP due to common cause = 3.39E-4

$RHCC_R$ = Both RHR trains fail to run for T_M = 24 hr due to common cause = 2.22E-4

RHB_M = Maintenance unavailability for standby pump

= 2 * $RH1_M$ = 0.224

7.2 Electric Power

7.2.1 System Description (SSPSA Section D.2)

Offsite electric power is provided to Seabrook Station through three 345KV lines connecting with the New England grid - Newington, Scobie Pond, and Tewksbury (under construction). During shutdown, offsite power to the 4160Vac essential buses (E5 and E6) is via two Reserve Auxiliary Transformers (RAT), one to each bus. Offsite power connections to the esential buses can also be made through the Generator Step Up Transformer (GSU) to two Unit Auxiliary Transformers (UATs).

The two emergency diesel generators are independent sources, each powering one of the 4160V essential buses (E5 and E6). One diesel is sufficient to power safe shutdown loads and to maintain the plant to shutdown condition. Each diesel has a set of support systems considered internal to the diesel system, including the air intake and exhaust, the starting air system, and the lube oil system. Support systems considered external (with regard to failure data) are the fuel oil system (storage tank, day tank, and transfer pump), cooling water system (closed loop cooled by service water), room ventilation (fans and dampers), and DC control power.

Technical Specifications require both diesels and two offsite circuits to be operable, for Modes 1 through 4, with a 24 hour allowed outage time for one diesel. In Modes 5 and 6, one diesel and one offsite circuit are required to be operable. The offsite circuits are assumed operable during shutdowns except for unplanned line outages. In shutdown the diesels are assumed to be available unless in maintenance or annual inspection. Also, both diesels must be available when the RCS is drained (Condition X) to support RHR. It is assumed that planned diesel maintenance occurs only when the RCS is filled (Condition W).

Each diesel is assumed be unavailable for between 2 and 10 days per year during the refueling outage to complete planned maintenance and repairs. The duration is assumed to be distributed in a three bin histogram as follows:

DUR_1 = 2 days, WT_1 = 0.1

DUR_2 = 7 days, WT_2 = 0.8

DUR_3 = 10 days, WT_3 = 0.1

The annual maintenance contribution to diesel unavailability is:

$$DG_{M1} = DUR * FREQ = 1.12E-1 \text{ (mean)}$$

where:

$$DUR = 48 \text{ hr} * 0.1 + 168 \text{ hr} * 0.8 + 240 \text{ hr} * 0.1$$

$$= 163 \text{ hours}$$

$$FREQ = \frac{1}{t_W} = \frac{1}{1455 \text{ hr}}$$

where t_W = annual average time in RCS Condition W (filled) (Section 9.2).

Infrequently each diesel undergoes a major overhaul in which the diesel is unavailable for an estimated 31 days. The most likely frequency for this overhaul is 10 years (with a likelihood of 0.8), and a minimum and maximum value of 4 years and 40 years (each with a likelihood of 0.1). This unavailability of one diesel due to overhaul is equal to the following fraction:

$$DG_{M2} = DUR * FREQ = 5.5E-2 \text{ (mean)}$$

$$\text{where } DUR = 31 \text{ days} * 24 \text{ hr/d} = 744 \text{ hr}$$

$$FREQ = \frac{0.1}{4 \text{ yr} * t_W} + \frac{0.8}{10 \text{ yr} * t_W} + \frac{0.1}{40 \text{ yr} * t_W}$$

$$= 7.4E-5 \text{ per hour}$$

The total maintenance and overhaul contribution to single diesel unavailability is:

$$DG_M = DG_{M1} + DG_{M2} = 1.67E-1 \text{ (mean)}$$

Electric Power system is quantified for three conditions:

(1) Diesel Generator operation in the Support System Tree (Section 7.2.2),

(2) Loss of Offsite Power initiating event (Section 7.2.3), and

(3) Electric power recovery (Section 7.2.4).

AC electric power is quantified in the Support Systems tree only when offsite power is lost, i.e., with initiators LOSP, TCTL, etc. From the SSPSA it was determined that, with offsite power available, the AC electric power system is very reliable (SSPSA p. D.2-64); thus, its failure is not questioned. The same conclusion is assumed to hold for the plant at shutdown.

7.2.2 Diesel Generator Top Events

The diesel generators are modeled in the Support System Tree as top events GA (Train A fails to operate for 24 hours given LOSP) and GB (Train B fails to operate for 24 hours given LOSP). Diesel unavailability is quantified for two sets of initiators:

(1) loss of offsite power with the RCS filled - LOSP(W), and

(2) loss of offsite power with the RCS drained - LOSP(X)

The mission time for each set above is 24 hours. The electric power recovery model in Section 7.2.4 includes credit for recovery of diesels or offsite power.

For loss of offsite power with all support systems available and RCS Condition W (Filled), the dual diesel system unavailability is:

o $DG1 = DGAB_{24} + 2 * DG_M * DGA_{24}$

$= 4.6E-2$

where:

$DGAB_{24}$ = diesel trains A and B fail to start or fail to run for 24 hours = 1.47E-2 (SSPSA Table D.2-12 with mission time extended from 6 hours to 24 hours)

DGA_{24} = single diesel generator fails to start or fails to run for 24 hours = 9.25E-2 (SSPSA Table D.2-12 with mission time extended from 6 to 24 hours)

DG_M = diesel generator planned maintenance unavailability

= 0.167 (from Section 7.2.1)

For RCS Condition X (Drained), the dual diesel system unavailability is:

o $DG2 = DGAB_{24} = 1.5E-2$

For loss of offsite power with loss of support train A or B and RCS Condition W,

o $DG1_A = DG1|\text{loss of support train B} = DGA_{24} = 9.3E-2$

o $DG1_B = DG1|\text{loss of support train A} = DGA_{24} + DG_M$

$= 2.6E-1$

For loss of offsite power with loss of support train and RCS Condition X,

o $DG2_A = DG2_B = DGA_{24}$

$= 9.3E-2$ (mean)

Using the system and single train unavailabilities above, split fractions for top events GA and GB are calculated using the methodology in the SSPSA Section 5.4.2.

$GA1 = \overline{GA}|LOSP(W) = DG1 + DG1_A = 0.14$

$GA2 = \overline{GA}|LOSP(X) = DG2 + DG2_A = 0.11$

$GAF = \overline{GA}|$Power to Bus E5 guaranteed failed $= 1.0$

$GB1 = \overline{GB}|LOSP(W) = DG1 + DG1_B = 0.31$

$GBA = \overline{GB}|GA \text{ and } LOSP(W) = \dfrac{DG1_B}{1-(DG1 + DG1_A)} = 0.30$

$GBB = \overline{GB}|\overline{GA} \text{ and } LOSP(W) = \dfrac{DG1}{DG1 + DG1_A} = 0.33$

$GB2 = \overline{GB}|LOSP(X) = DG2 + DG2_B = 0.11$

$GBC = \overline{GB}|GA \text{ and } LOSP(X) = \dfrac{DG2_B}{1-(DG2 + DG2_A)} = 0.10$

$GBD = \overline{GB}|\overline{GA} \text{ and } LOSP(X) = \dfrac{DG2}{DG2 + DG2_A} = 0.14$

$GBF = \overline{GB}|$Power to Bus E6 guaranteed failed $= 1.0$

7.2.3 Loss of Offsite Power Initiating Event

The frequency of the "loss of offsite power during shutdown" initiating event is given by the following expressions:

$LOSP(X) = (FR(SD) * LOSP' + LOSP_{IV}) * FR(X) = 3.0E-2$ (mean)

$LOSP(W) = (FR(SD) * LOSP' + LOSP_{IV}) * FR(W) = 2.7E-2$ (mean)

where FR(SD) = fraction of time the plant is in the shutdown mode = 0.37 (from Table 9-3)

LOSP' = frequency of LOSP while in normal (at-power) configuration = 0.135/year (SSPSA Section 6.6)

$LOSP_{IV}$ = frequency of LOSP while in the shutdown because of special maintenance conditions = 0.009/year (Reference 8, Table 2-1)

FR(X) = fraction of the shutdown that the RCS is in Condition X - RCS drained to the vessel flange or to the hot leg mid-plane.

= 0.51 (from Table 9-3)

FR(W) = fraction of the shutdown that the RCS is in Condition W - RCS full with secondary cooling available.

= 0.45 (from Table 9-3)

The frequencies of LOSP' and $LOSP_{IV}$ are used to account for the increased likelihood of loss of offsite power during a shutdown, i.e., human or equipment errors occurring during maintenance or testing which is done only during an outage. e frequency of loss of offsite power from the SSPSA (LOSP') is assumed to be the "background" rate of LOSP. The frequency of LOSP due to special maintenance conditions is assumed to add to this background rate when the background rate is adjusted for the shutdown fraction. The frequency of LOSP due to maintenance conditions is taken from NSAC-80 (Reference 8). Category IV events in NSAC-80 are the LOSPs which occur during shutdown and are due to special maintenance conditions which exist only at shutdown. This frequency ($LOSP_{IV}$) includes the condition that the plant is shutdown so it is not necessary to multiply by the shutdown fraction.

7.2.4 Electric Power Recovery

The electric power recovery model includes the following:

(1) probability of diesel generators to operate given loss of offsite power, and

(2) probability of recovery of offsite power or diesel generators given failure of the diesel generators and loss of offsite power.

The mission time in the model is 24 hours, consistent with the other systems analyses in this study. Electric power recovery is a function of the recoverability of offsite power and diesels and the time avalable with no heat removal before core damage. These factors are determined by the initiating event as shown in Table 7-7. The electric power unavailabilities including recovery (EPR) were calculated using a Monte Carlo uncertainty model described in Section 5.6. The electric power recovery fractions (ER) listed in Table 7-7 are the ratios of the electric power unavailability with recovery to the electric power unavailability with no recovery. These fractions are used in the point estimate model to adjust the unavailability of non-recovered electric power.

7.3 Primary Component Cooling Water System (PCC)

7.3.1 System Description (SSPSA Section D.4)

The PCC system consists of two separate closed loop cooling trains which remove heat from various primary components. The system serves as an intermediate fluid barrier between the reactor coolant system and service water system to minimize the potential for radioactive releases to the environment. During shutdown, the PCC system provides cooling to the RHR pump seals and removes core decay heat through the RHR heat exchanger. Each PCC train has two pumps, one operating, one in standby, and one heat exchanger. One pump in one train is sufficient to remove shutdown heat loads.

The PCC pumps are located in the Primary Auxiliary Building (PAB) which is cooled by the PAH Air Handling System (PAH). The PCC pump area is rather large and open and the ventilation systems are reliable, as discussed in SSPSA Section D.4. Ventilation is not a significant contribution to PCC failure.

The PCC system is not required to operate in Modes 5 and 6, except in support of RHR. Both trains are assumed to operate throughout the shutdown (except for planned maintenance on a single train) because of RHR operability requirements and other plant cooling loads. For modeling convenience, Train A is assumed to be cooling the operating RHR train and Train B the standby RHR train, consistent with RHR (Section 7.1.1). Maintenance which causes the standby train to be unavailable is modeled in the B train.

Planned maintenance is assumed for the standby pumps for between 2 and 10 days each year. Since t_X and t_W are approximately equal, it is assumed that there is a 50-50 chance of maintenance occurring during either Condition X or Condition W. The duration is assumed to be distributed in a three bin histogram as follows:

$$DUR_1 = 2 \text{ days}, \quad WT_1 = 0.1$$

$$DUR_2 = 7 \text{ days}, \quad WT_2 = 0.8$$

$$DUR_3 = 10 \text{ days}, \quad WT_3 = 0.1$$

The maintenance unavailability for a single PCC pump is:

$$P11A_M(X) = DUR * FREQ(X) = 0.050 \quad \text{(mean)}$$

$$P11A_M(W) = DUR * FREQ(W) = 0.056 \quad \text{(mean)}$$

where:

$$DUR = (48 \text{ hr}) * 0.1 + (168 \text{ hr}) * 0.8 + (240 \text{ hr}) * 0.1 = 163 \text{ hr}$$

$$FREQ(X) = \frac{0.5 \text{ maint}}{\text{year}} * \frac{1 \text{ year}}{t_X} = \frac{0.5}{1627 \text{ hr}}$$

$$FREQ(W) = \frac{0.5 \text{ maint}}{\text{year}} * \frac{1 \text{ year}}{t_W} = \frac{0.5}{1455 \text{ hr}}$$

Planned maintenance occurs at a less frequent basis on heat exchangers or other components which make an entire train inoperable. This is assumed to require two weeks and to occur at a frequency of every two years (WT = 0.1), every 4 years (WT = 0.8) or every 10 years (0.1). PCC train maintenance can only occur when the RCS is filled (RCS condition = W). The maintenance unavailability contribution to one train is:

$$HXA_M = DUR' * FREQ'(W) = 0.060$$

where:

$$DUR' = 336 \text{ hr}$$

$$FREQ'(W) = \frac{0.1}{2 \text{ yr} * t_W} + \frac{0.8}{4 \text{ yr} * t_W} + \frac{0.1}{10 \text{ yr} * t_W}$$

$$= 1.79E-4$$

where t_W is defined and quantified in Section 9.2.

PCC system is quantified for three conditions:

(1) PCC operation in the Support System Tree.

(2) Loss of the Operating PCC Train Initiating Event, and

(3) Loss of All PCC Initiating Events.

7.3.2 PCC Top Events

PCC is modeled in the Support System Tree as t[illegible] events PA (operating train of PCC fails to operate for 24 hours) and PB (the standby train of PCC fails to start and operate for 24 hours).

For the RCS filled condition (W), the system unavailability with all support systems available is:

o $$PCC1 = PCC(1A) + 2 * PCC(2A) * (2 * B * P11A_M(W) + HXA_M(W))$$

$$= 1.1E-4$$

Where PCC(1A) is two train hardware unavailability and the second term accounts for planned maintenance unavailability

PCC(1A) = PCC unavailability with all support systems available

= 1.54E-6 (SSPSA p. D.4-46)

PCC(2A) = PCC single train unavailability

= 9.01E-4 (SSPSA, p. D.4-46)

B = Operating PCC pump failed

= 3.74E-3 (SSPSA, p. D.4-35)

$P11A_M(W)$ = Standby pump in planned maintenance (RCS Condition W)

= 5.6E-2

$P11A_M(X)$ = Standby pump in planned maintenance (RCS Condition X)

= 5.0E-2

$HXA_M(W)$ = Standby train in planned maintenance

= 6.0E-2

For train A of support systems available, with RCS filled (W),

o $PCC1_A = PCC(2A) + 2 * B * P11A_M(W)$

$= 1.3E-3$

For train B of support systems available, with RCS filled (W),

o $PCC1_B = PCC(2A) + 2 * B * P11A_M(W) + HXA_M(W)$

$= 6.1E-2$

For the drained RCS condition (X), the system unavailability is,

o $PCC2 = PCC(1A) + 2 * PCC(2A) * (2 * B * P11A_M(X))$

= 2.[illegible]

For a single train [illegible]upport systems available, with RCS drained (X).

o $PCC2_A = PCC2_B = PCC(2A) + 2 * B * P11A_M(X) = 1.3E-3$

For a LOSP initiating event with RCS filled (W), the system unavailability is:

o $PCC3 = PCC(1B) + 2 * PCC(2B) * (2 * B * P11A_M(W) + HXA_M(W))$

$= 1.3E-4$

where: PCC(1B) = PCC Unavailability with all Support Systems Available and LOSP

= 1.25E-5 (SSPSA p. D.4-46)

PCC(2B) = PCC Unavailability with Single Support Train Available and LOSP

= 9.46E-4 (SSPSA p. D.4-46)

For train A of support systems available and LOSP with RCS filled (W),

o $PCC3_A = PCC(2B) + 2 * B * P11A_M(W) = 1.4E-3$

For train B of support systems available and LOSP with RCS filled (W),

$PCC3_B = PCC(2B) + 2 * B * P11A_M(W) + HXA_M(W)$

$= 6.1E-2$

For a LOSP initiating event with RCS drained (X), the system unavailability is:

o $PCC4 = PCC(1B) + 2 * PCC(2B) * (2 * B * P11A_M(X))$

$= 1.3E-5$

For a LOSP initiating event with RCS drained (X) and a single train of support systems available,

o $PCC4_A = PCC4_B = PCC(2B) + 2 * B * P11A_M(X)$

$= 1.3E-3$

Using the system and single train results, split fractions for top events PA and PB can be calculated using the methodology in the SFPSA Section 5.4.2.

$PA1 = \overline{PA}|\text{RCS Filled (W)} = PCC1 + PCC1_A = 1.4E-3$

$PA2 = \overline{PA}|\text{RCS Drained (X)} = PCC2 + PCC2_A = 1.3E-3$

$PA3 = \overline{PA}|$LOSP with RCS Filled (W) $= PCC3 + PCC3_A = 1.5E-3$

$PA4 = \overline{PA}|$LOSP with RCS Drained (X) $= PCC4 + PCC4_A = 1.3E-3$

$PAF = \overline{PA}|$LPCC or LPCCA $= 1.0$

$PB1 = \overline{PB}|$RCS Filled (W) $= PCC1 + PCC1_B = 6.1E-2$

$$PBA = \overline{PB}|\text{PA and RCS Filled (W)} = \frac{PCC1_B}{1-(PCC1 + PCC1_A)} = 6.1E-2$$

$$PBB = \overline{PB}|\overline{PA}\text{ and RCS Filled (W)} = \frac{PCC1}{PCC1 + PCC1_A} = 7.9E-2$$

$PB2 = \overline{PB}|$RCS Drained (X) $= PCC2 + PCC2_B = 1.3E-3$

$$PBC = \overline{PB}|\text{PA and RCS Drained (X)} = \frac{PCC2_B}{1-(PCC2 + PCC2_A)} = 1.3E-3$$

$$PBD = \overline{PB}|\overline{PA}\text{ and RCS Drained (X)} = \frac{PCC2}{PCC2 + PCC2_A} = 1.7E-3$$

$PB3 = \overline{PB}|LOSP(W) = PCC3 + PCC3_B = 6.1E-2$

$$PBE = \overline{PB}|\text{PA and LOSP(W)} = \frac{PCC3_B}{1-(PCC3 + PCC3_A)} = 6.1E-2$$

$$PBG = \overline{PB}|\overline{PA}\text{ and LOSP(W)} = \frac{PCC3}{PCC3 + PCC3_A} = 8.7E-2$$

$PB4 = \overline{PB}|LOSP(X) = PCC4 + PCC4_B = 1.3E-3$

$$PBH = \overline{PB}|\text{PA and LOSP(X)} = \frac{PCC4_B}{1 - (PCC4 + PCC4_A)} = 1.3E-3$$

$$PBI = \overline{PB}|\overline{PA}\text{ and LOSP(X)} = \frac{PCC4}{PCC4 + PCC4_A} = 1.0E-2$$

$PBF = \overline{PA}|LPCC = 1.0$

7.3.3 Loss of PCC Train A Initiating Event (LPCCA)

Loss of PCC Train A (LPCCA) while in shutdown is modeled as an "initiating event" because it is a support system to the operating RHR train. This event causes a loss of decay heat removal. Both trains of PCC are assumed to be operable during most of the shutdown period (except for planned maintenance on a single train) because PCC trains also cool other service loads such as the fuel pool and waste processing in addition to cooling RHR. However, only loss of the PCC train supporting the operating RHR train is considered a transient.

The frequency of loss of PCC Train A during shutdown is quantified for the RCS in Condition X (RCS drained) and Condition W (RCS filled). The unavailability expression given below is based on the following logic: The operating PCC pump fails to run during the shutdown period and the standby PCC pump fails to start or is unavailable due to planned maintenance or fails to run while the first pump is being repaired or their is common cause failure of the PCC pumps to run.

$$LPCCA(X) = (P_{RUN} * T(X))_A * (P_S + P11A_M(X) + P_{RUN} * T_R)_C + (BETA_R * P_{RUN} * T_R)_{A,C}$$

$$= 2.92E\text{-}3 \text{ per year}$$

$$LPCCA(W) = (P_{RUN} * T(W))_A * (P_S + P11A_M(W) + P_{RUN} * T_R)_C + (BETA_R * P_{RUN} * T_R)_{A,C}$$

$$= 2.91E\text{-}3 \text{ per year}$$

where:

P_{RUN} = failure of the operating PCC pump in Train A
= 3.36E-5/hour (ZIPMOR in Table 9-1).

P_S = failure of the standby pump in Train A to start
= 2.35E-3/demand (ZIPMOS in Table 9-1).

$P11A_M(X)$ = PCC pump planned maintenance unavailability with RCS Condition X
= 5.0E-2 (Section 7.3.1)

$P11A_M(W)$ = PCC pump planned maintenance unavailability with RCS Condition W
= 5.6E-2 (Section 7.3.1)

$T(X)$ = mission time for operating pump = annual average time in RCS Condition X - RCS Drained
= 1627 hr per year (see Section 9.2).

$T(W)$ = mission time for operating pump = annual average time in RCS Condition W - RCS filled

= 1455 hr per year (see Section 9.2).

T_R = mission time for standby pump = mean time to repair PCC pump

= 20.9 hr (see SSPSA Section 6.4).

$BETA_R$ = common cause beta factor for PCC pump fails to run

= 2.32E-2 (ZBPCWR in Table 9-2).

A,C = normally operating PCC pump (A), standby PCC pump (C) in the operating train

These initiating events are quantified assuming that pump failure and repair are the dominant failure and recovery sequences. Other failures are less likely or do not affect cooling to the RHR pump and heat exchanger.

7.3.4 Loss of Both Trains of PCC Initiating Event (LPCC)

Loss of both trains of PCC during (LPCC) shutdown is quantified using the failure expression for loss of PCC during operation from SSPSA Section 6.6 but modifying the run time for the operating pump and including planned maintenance unavailability. Loss of both trains of PCC results in loss of decay heat removal and makes recovery more difficult.

Using the shutdown duration as the mission time and the shutdown maintenance terms developed in Section 7.3.1, the LPCC frequency can be calculated using the expression from SSPSA Section 6.6.3.2.3.

The frequency of LPCC is quantified for the RCS in Condition X (RCS drained) and Condition W (RCS filled). The expression below represents the following failure logic: The running pump in first train fails and the standby pump fails to start and the opposite train fails to operate or the running pump in the first fails and the opposite train running pump fails and both standby pumps fail to start or both running pumps fail due to a common cause and both standby pumps fail independently or from common cause.

$$LPCC(X) = 2 * P_{RUN} * T(X) * [P_S * Q_{TRAIN}(X) + BETA_S * P_S * Q'_{TRAIN}(X)] + BETA_R * P_{RUN} * T_R * [BETA_S * P_S + P_S^2]$$

$$= (1.1E-1) * [3.2E-6] + (1.63E-5) * [9.13E-5]$$

$$= 3.5E-7 \text{ per year}$$

$$LPCC(W) = 2 * P_{RUN} * T(W) * [P_S * Q_{TRAIN}(W) + BETA_S * P_S * Q'_{TRAIN}(W)] + BETA_R * P_{RUN} * [BETA_S * P_S + P_S^2]$$

$$= (9.8E-2) * [1.5E-4] + (1.6E-5) * [9.1E-5]$$

$$= 1.5E-5 \text{ per year}$$

where:

P_{RUN} = PCC pump fails to run = 3.36E-5/hour (Z1PMOR in Table 9-1).

$BETA_R$ = Common cause beta factor for pump fails to run

= 2.32E-2 (ZBPCWR in Table 9-2).

P_S = PCC pump fails to start (Z1PMOS in Table 9-1).

= 2.35E-3

$BETA_S$ = Common cause beta factor for pumps fail to start

= 3.65E-2 (ZBPCWS in Table 9-2).

T(X) = Mission time = Time in RCS Condition X

= 1627 hours/year (Section 9.2).

T(W) = Mission time = Time in RCS Condition W

= 1455 hours/year

$Q_{TRAIN}(W)$ = unavailability of one complete train of PCC (including planned maintenance unavailability) over the mean repair time of the first pump (about 24 hours)

= $PCC1_B$ = 6.1E-2 (Section 7.3.2)

$Q_{TRAIN}(X)$ = $PCC2_B$ = 1.3E-3 (Section 7.3.2)

$Q'_{TRAIN}(W)$ = unavailability of one train of PCC including the normal running pump but excluding the standby pump (which in this term has failed in common cause mode with the standby pump in the other train)

= A + C + $HXA_M(W)$ = 6.1E-2

$Q'_{TRAIN}(X)$ = A + C = 1.4E-3

where:

A = PCC pump run block

= 8.21E-4 (SSPSA p. D.4-35)

C = PCC series components

= 5.88E-4 (SSPSA p. D.4-37)

HXA_M = PCC heat exchanger maintenance

= 6.0E-2 (Section 7.3.1)

7.4 Service Water System (SW)

7.4.1 System Description (SSPSA Section D.3)

The Service Water System provides cooling water to transfer the heat loads in the primary and secondary portions of the plant to the ultimate heat sink. The Service Water System consists of two independent and redundant trains, each of which supplies cooling water to a primary component cooling water heat exchanger and a diesel jacket water cooler. Both trains combine into a common header before supplying cooling water to the condenser water box, priming pump seal, water heat exchangers, and the secondary component cooling water heat exchangers. The SWS normally uses the ocean as the ultimate heat sink. If the service water tunnel, pumphouse, or pumps are unavailable, a mechanical draft cooling tower serves as the ultimate heat sink. Each train of service water consists of two service water pumps and one cooling tower pump, only one of which is needed for success. Ventilation and heating systems are provided in the service water pumphouse pump area, the switchgear area, and the cooling tower pump and switchgear areas.

The SWS is not required to be operable in Modes 5 and 6 except in support of RHR. Both trains of Service Water will remain operating throughout the shutdown except during single train maintenance because of RHR operability requirements and other plant cooling loads. For modeling convenience, Train A is assumed to be cooling the operating RHR train and Train B, the standby RHR train. Maintenance which causes the standby train to be unavailable is modeled in the B train.

Planned maintenance is assumed to occur to the standby pumps in each train at the same frequency and duration as with PCC trains - once per year for approximately one week. This maintenance can occur anytime during the outage. Since t_X and t_W are approximately equal, it is assumed that there is a 50-50 chance of maintenance occurring during the Condition X or Condition W. The maintenance contribution to unavailability for a single SW train is:

$P41A_M(X)$ = 0.050 (from $P11A_M(X)$ in Section 7.3.1)

$P41A_M(W)$ = 0.056 (from $P11A_M(W)$ in Section 7.3.1)

The cooling tower pumps are assumed to be in planned maintenance during shutdown at the same rate as SW pumps:

$P110A_M(X)$ = 0.050

$P110A_M(W)$ = 0.056

Additional planned maintenance requires the standby train to be inoperable for a longer period of time but less frequently. It is assumed to require about 2 weeks every four and one-half years, consistent with HXA_M in the PCC system. SW train maintenance can occur only when the RCS is filled (RCS Condition Designator W). The maintenance unavailability contribution to a single train is:

SWB_M = 0.060 (from HXA_M in Section 7.3.1)

During RCS drained conditions (RCS Condition X), two trains of RHR (and SW) are required to be operable. There is no unavailability contribution from planned maintenance on the standby train when the RCS is drained.

The SW system is quantified for three conditions:

(1) SW operation in the Support System Tree,

(2) Loss of the Operating SW Train Initiating Event,

(3) Loss of All SW Initiating Events.

7.4.2 SW Top Events

The Service Water System is modeled in the Support System Tree as top events WA (operating train of SW fails to operate for 24 hours) and WB (standby train of SW fails to start and operate for 24 hours). These top events are quantified for four separate boundary conditions: RCS filled (W) for which train B planned maintenance is included; RCS drained (X) for which only standby pump maintenance is included; loss of offsite power initiators in RCS Condition W; and loss of offsite power initiators in RCS Condition X. The last two conditions require restart of the operating SW train.

The system unavailability for the RCS filled condition (W,Y) is quantified for various combinations of equipment available:

For all equipment available with RCS filled

o $SW1 = [SWAB + 2 * SWA * SWB_M + 4 * SWA * (A * P41A_M(W)_B]$

$* [CTAB + 2 * CTA * P110A_M(W) + CP1_{CT}]$

$= (3.02E-4) * (9.17E-3) = 2.8E-6$

where

$SWAB$ = Both trains of SW fail to operate for 24 hours, including common cause failure of pump and MOVs (No LOSP, No S Signal)

= 6.43E-6 (SSPSA p. D.3-53)

SWA = single SW train fails to operate

= $T + S1 + P1A + Y1 + A * C + E + Z$

= 2.46E-3 (SSPSA p. D.3-20 to 29)

SWB_M = Standby train maintenance unavailability

= 6.0E-2 (Section 7.4.1)

$P41A_M(W)$ = Standby pump maintenance unavailability

= 5.6E-2 (Section 7.4.1)

A = Service Water pump fails to run for 24 hours

= 8.09E-4 (SSPSA p. D.3-26)

$CTAB$ = Both cooling tower trains fail to start or run

= 2.46E-3 (SSPSA p. D.3-53)

CTA = Cooling tower single train fails to start or run

= 4.83E-2 (SSPSA p. D.3-53)

$P110A_M(W)$ = Cooling tower planned maint. unavailability

= 5.6E-2 (Section 7.4.1)

$OP1_{CT}$ = Operator fails to initiate cooling tower operation

= 1.3E-3 (Section 6.4.1)

For train A available, with RCS filled (W) -

o $SW1_A = [SWA + 2 * A * P41A_M(W)] * [CTA + P110A_M(W) + OP1_{CT}]$

$= (2.55E-3) * (0.106) = 2.7E-4$

For train B available, with RCS filled (W) -

o $SW1_B = [SWA + 2 * A * P41A_M(W) + SWB_M] * [CTA + P110A_M(W)$
$+ OP1_{CT}]$

$= (6.3E-2) * (.106) = 6.7E-3$

For the RCS drained condition (X), the system unavailability is quantified for equipment availabilities as follows:

For all equipment available with RCS drained -

o $SW2 = [SWAB + 4 * SWA * (A * P41A_M(X)_B] * [CTAB + 2 *$
$CTA * P110A_M(X) + OP1_{CT}]$

$= (6.83E-6) * (8.6E-3) = 5.9E-8$

where

$P41A_M(X) = P110A_M(X) = 5.0E-2$

For a single train available, with RCS drained (X) -

o $SW2_A = SW2_B = [SWA + 2 * A * P41A_M(X)] *$
$[CTA + P110A_M(X) + OP1_{CT}]$

$= (2.54E-3) * (1.00E-1) = 2.5E-4$

For a LOSP (or other internal/external) initiating event, it is the Cooling Towers are assumed unavailable because of the short time for operator action to provide cooling to the diesel generators.

For all equipment available with LOSP and with RCS Condition W:

o $SW3 = [SWAB' + 2 * SWA' * SWB_M]$

$= 3.4E-3$

where

SWAB' = Both SW trains fail to start or run given LOSP, including common cause failure of pumps and MOVs

= 1.10E-3 (SSPSA p. D.3-53)

SWA' = Single SW train fails to start or run given LOSP

= 1.93E-2 (SSPSA p. D.3-53)

SWB_M = Standby SW train in maintenance

= 6.0E-2 (Section 7.4.1)

For train A available with LOSP and with RCS Condition W:

o $SW3_A = SWA'$

$= 1.9E-2$

For train B available with LOSP and with RCS Condition W:

o $SW3_B = SWA' + SWB_M$

$= 7.9E-2$

For all equipment available with LOSP, with RCS Condition X:

o $SW4 = SWAB' = 1.1E-3$

For a single train of support systems available with LOSP and with RCS Condition X:

o $SW4A = SW4B = SWA'$

$= 1.9E-2$

Using the systems and single train unavailabilities, split fractions for top events WA and WB are calculated using the methodology in the SSPSA Section 5.4.2.

$WA1 = \overline{WA}|\text{RCS Filled (W)} = SW1 + SW1_A = 2.7E-4$

$WA2 = \overline{WA}|\text{RCS Drained (X)} = SW2 + SW2_A = 2.5E-4$

$WA3 = \overline{WA}|\text{LOSP(W)} = SW3 + SW3_A = 2.2E-2$

$WA4 = \overline{WA}|\text{LOSP(X)} = SW4 + SW4_A = 2.0E-2$

$WAF = \overline{WA}|\text{LOSW or LSWA} = 1.0$

$WB1 = \overline{WB}|\text{RCS Filled (W)} = SW1 + SW1_B = 6.7E-3$

$WBA = \overline{WB}|\text{WA and RCS Filled (W)} = \dfrac{SW1_B}{1-(SW1 + SW1_A)} = 6.7E-3$

$WBB = \overline{WB}|\overline{WA}$ and RCS Filled (W) $= \dfrac{SW1}{SW1 + SW1_A} = 1.0E-2$

$WB2 = \overline{WB}|$RCS Drained (X) $= SW2 + SW2_B = 2.5E-4$

$WBC = \overline{WB}|WA$ and RCS Drained (X) $= \dfrac{SW2_B}{1-(SW2 + SW2_A)} = 2.5E-4$

$WBD = \overline{WB}|\overline{WA}$ and RCS Drained (X) $= \dfrac{SW2}{SW2 + SW2_A} = 2.4E-4$

$WB3 = \overline{WB}|LOSP(W) = SW3 + SW3_B = 8.2E-2$

$WBE = \overline{WB}|WA$ and $LOSP(W) = \dfrac{SW3_B}{1-(SW3 + SW3_A)} = 8.1E-2$

$WBG = \overline{WB}|\overline{WA}$ and $LOSP(W) = \dfrac{SW3}{SW3 + SW3_A} = 1.5E-1$

$WB4 = \overline{WB}|LOSP(X) = SW4 + SW4_B = 2.0E-2$

$WBH = \overline{WB}|WA$ and $LOSP(X) = \dfrac{SW4_B}{1-(SW4 + SW4_A)} = 1.9E-2$

$WBI = \overline{WB}|\overline{WA}$ and $LOSP(X) = \dfrac{SW4}{SW4 + SW4_A} = 5.5E-2$

$WBF = \overline{WB}|LOSW = 1.0$

7.4.3 Loss of SW Train A Initiating Event (LSWA)

Loss of Service Water Train A (LSWA) while in shutdown is similar to the LPCCA initiating event for failure consequences and frequencies. Offsite power is available for this initiator and the Service Water System has an additional redundant Cooling Tower pump in each train. The quantification for loss of Train A of SW is:

$$\begin{aligned}LSWA(W) &= [(P_{RUN} * T(W))_A * (P_S + P41A_M(W) + P_{RUN} * T_R)_C \\ &\quad + (BETA_R * P_{RUN} * T_R)_{A,C}] * (OP1_{CT} + CTA + P110_M(W)) \\ &= [2.96E-3] * [0.106] = 3.1E-4\end{aligned}$$

$$\begin{aligned}LSWA(X) &= [(P_{RUN} * T(X))_A * (P_S + P41A_M(X) + P_{RUN} * T_R)_C \\ &\quad + (BETA_R * P_{RUN} * T_R)_{A,C}] * (OP1_{CT} + (CTA + P110M(X)) \\ &= [2.95E-3] * [.100] \\ &= 3.0E-4\end{aligned}$$

where the first term accounts for the Service Water pump in Train A failing to run, the second term accounts for the standby SW pump failing to start, unavailable due to maintenance, or failing to run while the first pump is restored, the third term accounts for common cause failure of SW pump to run, and the fourth term accounts for the Cooling Tower pump failing to start and run. The variables have the same quantification as that of LPCCA (Section 7.3.3) except for:

$P41A_M(W)$ = SW or CT pump planned maintenance unavailability, RCS Condition W

= 5.6E-2 (Section 7.4.2)

$P41A_M(X)$ = SW or CT pump planned maintenance unavailability, RCS Condition X

= 5.0E-2 (Section 7.4.2)

$BETA_R$ = common cause beta factor for SW pumps fail to run

= 7.62E-2 (ZBPSWR in Table 9-2).

$OP1_{CT}$ = operator fails to start Cooling Tower

= 1.3E-3 (Section 6.4.1)

7.4.4 Loss of All Service Water (LOSW)

Loss of all Service Water (LOSW) during shutdown is quantified similarly to the loss of both PCC trains in Section 7.3.4 except that Service Water has an additional Cooling Tower pump in each train. The loss of all service water during shutdown can be calculated using the expression from the SSPSA (Section 6.6.3.2.2) modified for the shutdown run time and planned maintenance:

$$LOSW(W) = [2 * P_{RUN} * T(W) * [P'_S(W) * A * C'(W) + BETA_S * P'_S(W) * A + P_S * SWB_M] + BETA_R * P_{RUN} * T(W) * [BETA_S * P_S + P'_S(W) P_S]] * CT(W) + [2 * P_{RUN} * T(W) * P'_S(W) * E]$$

$$= (9.8E-2 * [1.5E-4] + (3.7E-3) * [4.0E-4]) * 9.2E-3 + (1.8E-8)$$

$= 1.7E-7$ per year

$$LOSW(X) = [2 * P_{RUN} * T(X) * [P'_S(X) * A * C'(X) + BETA_S * P'_S(X) * A] + BETA_R * P_{RUN} * T(X) * [BETA_S * P_S + P'_S(X) * P_S]] * CT(X) + [2 * P_{RUN} * T(X) * P'_S(X) * E]$$

$$= [1.1E-1 * [7.1E-6] + (4.2E-3) * [3.8E-4]] * 8.6E-3 + (1.8E-8)$$

$$= 3.8E-8$$

where:

P_{RUN} = SW pump fails to run

= 3.36E-5 per hour (ZIPMOR in Table 9-1)

$BETA_R$ = Common cause pump fails to run

= 7.62E-2 (ZBPSWR in Table 9-2)

P_S = SW pump fails to start

= 2.35E-3 (ZIPMOS in Table 9-1)

$P'_S(W)$ = $P_S + P41A_M(W)$

= Pump fails to start or pump in maintenance

= 2.35E-3 + 5.6E-2

= 5.8E-2 (Section 7.4.1)

$P'_S(X)$ = $P_S + P41A_M(X)$ = 2.3E-3 + 5.0E-2 = 5.2E-2

$BETA_S$ = Common cause pumps fail to start

= 0.111 (ZBPSWS in Table 9-2)

T(W) = mission time (Time in RCS Condition W)

= 1455 hours per year

T(X) = mission time (Time in RCS Condition X)

= 1627 hours per year

A = SW pu p fails to run block

= 8.09I-4 (SSPSA, p. D.3-26)

$C'(W)$ = $C + P41A_M(W)$

= SW pump fails to start bloc + pump in maintenance

= 7.72E-3 + 5.6E-2

= 6.4E-2 (SSPSA, p. D.3-27 and this report Sectio 7.4.1)

$C'(X)$ = $C + P41A_M(X)$ = 7.72E-3 + 5.0E-2 = 5.8E-2

E = SW series components block

= 3.22E-6 (SSPSA, p. D.3-27)

SWB_M = SW train in maintenance

= 6.0E-2 (Section 7.4.2)

$CT(W)$ = Cooling tower unavailability = $CTAB + 2 * CTA * P110A_M(W) + OP1_{CT}$

= 9.2E-3 (Section 7.4.2)

$CT(X)$ = $CTAB + 2 * (CTA * P110A_M(X) + OP1_{CT}$

= 8.6E-3 (Section 7.4.2)

7.5 Other Systems Top Events

7.5.1 Secondary Cooling Cycle

System Description (SSPSA Sections D.9 and D.11)

This section includes the entire secondary cooling cycle - the Condensate Storage Tank (CST), Emergency Feedwater System (EFW), steam generators (SGs), and atmospheric relief valves (ARVs). The e gency feedwater system removes heat from the reactor coolant syst through flow to at least two of four operable steam generators and ste of at least two of four atmospheric relief valves. The EFW system consists of one motor driven pump and one turbine driven pump taking suction from the Condensate Storage Tank. To use the turbine driven pump would require the primary and secondary side to be repressurized. The startup feed pump also takes suction from the CST and can be aligned to the emergency feedlines. The startup feed pump can be powered from an emergency bus (opposite bus from the motor driven EFW pump). Other sources of makeup to the steam generators are possible (e.g., fire protection water) but these sources have not been included in the model. The ARVs are air-operated with air-cylinders providing backup power.

The system requires operator action to control EFW to prevent overfilling the steam generators and to control ARV position. Operator action is not included in the quantification because of the long time available using just the inventory of water in the steam generators. Based on Appendix B, more than 20 hours are available before core uncovery using the inventory in four steam generators. Based on the long time available, it is assumed that failure of secondary cooling would be due to hardware failures of EFW only. Even this assumption (that EFW is needed) is conservative based on the long time available with just boil off of the secondary inventory.

The primary reactor coolant system must be intact (i.e., RCS head, S/G manways on) for the secondary cooling cycle to be operable. Secondary cooling is not operable for Case B, Tree 2 and Case C, Tree 4 (RCS Condition X).

Maintenance

During shutdown, the EFW system and steam generators are not required to be operable if both RHR trains are operable. For all outages one or two steam generators are in dry layup (at one time) for testing or maintenance, and are unavailable. The maintenance contribution for the

EFW system from SSPSA Section D.9 is used.

The Secondary Cooling Cycle is quantified for use in the Transient and LOCA Event Trees in top event LC, alternate long-term cooling. The quantification from the SSPSA (Sections D.9 and D.11) is judged to be appropriate for shutdown.

This system is quantified for the following cases for procedure-initiated events:

SCF - Primary system open, secondary cooling inoperable (RCS Conditions X,Y).

SC1 - Both trains of EFW or one of two ARVs fail to operate, with primary system closed (RCS Condition W).

SC2 - Single train of EFW or one of two ARVs fail to operate, with the primary system closed (RCS Condition W).

SC3 - Turbine-driven EFW or one of two ARVs fail to operate, with the primary system closed (RCS Condition W).

(It is assumed that both steam generator sources of steam to the turbine-driven EFW pump are not in dry layup at the same time).

- SCF = 1.0
- SC1 = [EFW(1) + 2 * AOV] * NR_{SC} = 6.0E-5 (mean)

  where:

  EFW(1) = failure of both trains of EFW including common cause failure of pumps.

  = 4.34E-4 (SSPSA, p. D.9-51)

  AOV = failure of either ARV to open on demand in the operable steam generators

  = 1.52E-3 (ZIVAOD in Table 9-1)

- SC2 = [EFW(2) * 0.5 * [EFW(5) + SFP(1)] + 2 * AOV] * NR_{SC}

  = 6.0E-5 (mean)

  where:

  EFW(2) = failure of the turbine-driven EFW pump

= 4.77E-2 (SSPSA, p. D.9-51)

EFW(5) = failure of the motor-driven EFW pump

= 5.87E-3 (SSPSA, p. D.9-51)

SFP(1) = failure of the startup feed pump

= 1.50E-2 (SSPSA, p. D.9-51)

The recovery option modeled in NR is secondary cooling using fire suppression water into the steam generators (as discussed in Ref. 22, Section 8.4).

NR_{SC} = operator fails to recover secondary cooling, given at least 12 hours with core uncovery with no cooling. Because of the long time available, it is that NR is dominated by hardware failure of the fire suppression water system. The unavailability of the fire suppression system is used assuming no AC power available to the fire water pump.

NR_{SC} = 1.7E-2 (mean)

BE = 1.2E-2, EF = 3.1

o SC3 = $(EFW(2) + 2 * AOV) * NR_{SC}$

= 8.7E-4 (mean)

7.5.2 Primary System Relief Valves

System Description (SSPSA Section D.10)

During the RHR mode, primary system pressure relief is provided by the pressurizer PORVs or the RHR pump suction relief valves or pressurizer vent. Any one of these valves provides sufficient relief capacity to prevent a primary system overpressurization due to maximum charging flow from one charging pump.

The pressurizer PORVs (RC-PCV-456A,456B) are DC solenoid operated and discharge into the pressurizer relief tank (PRT). At power, the PORV pressure setpoint is 2385 psig. During shutdown, the PORV setpoint will automatically follow the reactor coolant temperature below 329°F to protect the primary system from low temperature overpressurization (LTOP). The LTOP control circuitry is discussed in Section 7.5.5.

The three-inch RHR relief valves (RC-V23,V89) are spring loaded with a setpoint of 450 psig and discharge to the PRT.

The primary system relief valves are quantified for failure to open on demand (top event VO) and failure to reclose (top event OC) for use in the Shutdown Transient Tree. Top event OC includes operator action to stop the overpressurization (OP_{OC}) and the relief valve hardware failure to close (VC). This section only addresses the hardware portion.

The top event quantification for the various possible relief valve combinations, taking credit for only one PORV, is as follows:

PORV	RHR RELIEF	VO	VC
1	2	1.29E-8	2.50E-2
1	1	1.03E-7	2.50E-2
0	2	3.03E-6	2.87E-3
0	1	2.42E-5	2.87E-3
1	0	4.27E-3	2.50E-2
0	0	1.0	0.0

For top event VO, the failure of the available relief valves to open is calculated by the failure expression:

$$VO = PO * RO$$

where:

PO = PORV fails to open

= 4.27E-3 (ZIVR3D in Table 9-1)

RO = Available RHR relief valves fail to open

= Q_{RV} = 2.42E-5 if only 1 RHR relief valve is available or

= $Q_{RV}^2 + BETA * Q_{RV}$ = 3.03E-6 if 2 RHR relief valves are available.

where:

BETA = generic common cause factor = 0.125 (ZBGN1A in Table 9-2)

For event VC, the failure of relief valves to reclose is calculated assuming that only one relief valve lifted.

VC = PC = PORV fails to reclose (ZIVR3C in Table 9-1)

= 2.50E-2 or

VC = RV = RHR relief valve fails to reclose (ZIVR1S in Table 9-1)

= 2.07E-3

The PORV is less likely to reclose so it is conservatively assumed to be open.

The possible combinations of relief valves opening and closing are conservatively binned to minimize the number of combinations of split fractions as follows:

VO1 = failure of 2 or more relief valves to open

= 3.03E-6

VO2 = failure of 1 relief valve to open

= 4.27E-3

VOF = no relief valves available

= 1.0

VC1 = failure of 1 relief valve to reclose

= 2.50E-2

7.5.3 ECCS

The ECCS functions of RHR, i.e., low pressure injection (LPI) and low pressure recirculation (LPR), are included in top event LC (alternate long term cooling) in the shutdown LOCA tree. These functions are questioned only for energetic LOCAs (i.e., LOCAs that occur when the RCS is pressurized - in RCS Condition W) that are not isolated early. For non-energetic LOCAs or LOCAs which are isolated early, vailability of normal decay heat removal function is questioned in top event RR (RHR restored). If RR fails, it is assumed that LPI and LPR are guaranteed failure.

The hardware unavailabilities for these functions can be taken directly from the SSPSA, modified to account for planned maintenance during shutdown. The contribution for planned maintenance of the RHR system has been developed in Section 7.1.3.

Planned maintenance requires each RHR train to be unavailable for one week each year. The maintenance contribution to the unavailability of functions LPI and LPR is:

$$RH1_M = 0.112$$

For energetic LOCAs which are not isolated (top event IR failed), the split fractions are quantified as follows:

For all support systems available and top event TP (pump tripped) successful,

o $LP1 = LP1' + 2 * LP2' * RH1_M$

$= 7.1E-3$ (mean)

where:

$LP1'$ = low pressure injection (1 of 2 RHR pumps to 2 of 4 cold legs) given all support systems available

= 4.35E-3 (SSPSA p. D.8-116)

$LP2'$ = low pressure injection given single support train available

= 1.23E-2 (SSPSA p. D.8-116)

o $LR1 = LR1' + 2 * LR2' * RH1_M$

$= 3.0E-3$ (mean)

where:

LR1' = low pressure recirculation given all support systems available

= LLLPR + SAB + HAB (SSPSA, pp. 8-116 to 118)

= 6.65E-4

LR2' = low pressure recirculation given single support train available

= $LLLPR_1$ + SA + HA (SSPSA, pp. 8-116 to 118)

= 1.03E-2

For Train A of support system failed or all support systems available and TP failed:

- o LP2 = LP2' + $RH1_M$

  = 1.2E-1 (mean)

- o LR2 = LR2' + RH1M

  = 1.2E-1 (mean)

For Train B of support systems failed and TP successful,

- o LP3 = LP2'

  = 1.2E-2 (mean)

- o LR3 = LR2'

  = 1.0E-2 (mean)

For no support trains available or Train B of support systems failed and TP failed, the functions are guaranteed failure.

- o LPF = 1.0
- o LRF = 1.0

7.5.4 Feed and Bleed Cooling

Feed and bleed cooling is an alternate method of removing decay heat which is modeled in the Transient and LOCA trees when normal RHR cooling is unavailable. Figure 7-3 shows the minimum charging flow needed to remove decay heat as a function of time. The earliest possible time to arrive in Mode 4 (hot shutdown) after shutdown is 4 hours (200° cooling at 50°F/hr), at which the required flow rate is about 220 gpm. If feed and bleed cooling was initiated at this time, the RWST could easily supply this flow rate for the 24 hour mission time (456,000 gal. vs. 220 * 60 X 24 = 316,800 gal.). The required flow rate would decrease to about 125 gpm after 1 day. The operators could also begin immediate makeup to the RWST.

In Modes 5 and 6, the Technical Specifications require either a minimum volume of 22,000 gal. in the RWST or 6,500 gal. in the boric acid storage tank. If the minimum volume (6,500 gal.) were available after the minimum time (about 12 hours), the operators would have about 40 minutes until the tank was drained. More realistically, after a week with the minimum RWST volume, the operators have 5.6 hours until the boric acid tank is drained. Borated water can be made up continuously at this rate (about 65 gpm).

The feed is provided by one of four high pressure charging or SI pumps. During shutdown all pumps except one charging pump are in pull-to-lock with the breakers racked out. For all support systems available, the unavailability of the feed (FD1) is quantified based on the operating charging pump failing and the operator failing to re-energize the other charging/SI pumps, or the other pumps fail to operate.

- $FD1 = CP * [OP1_{FD} + SLHPI(2) * (S1B + MNT)]$

  $= 5.1E-6$

  where:

  CP = charging pump fails to operate for 24 hours

  = 3.36E-5/hr * 24 hr

$= 8.06E-4$

$OP1_{FD}$ = operator fails to rack in the charging/SI pumps within about 1 hour

= 6.3E-3 (Section 6.4.1)

SIB = SI pump fails to start and run

= 4.70E-3 (SSPSA p. D.8-48)

SLHPI(2) = SI pump and charging pump fail to start and run

= 1.95E-4 (SSPSA p. D.8-121)

MNT = planned maintenance unavailability of an SI or charging pump (assumed one week per year total for charging/SI pumps)

$= \frac{168 \text{ hr}}{3214 \text{ hr}}$

= 5.2E-2

For Train B of support systems unavailable and assuming the operating charging pump is the Train A:

o FD2 = CP * ($OP1_{FD}$ + SIB + MNT)

= 5.1E-5

For Train A of support systems unavailable, either the SI or charging pump must be re-energized at the switchgear.

o FD3 = $OP1_{FD}$ + SLHPI(2) + SIB * MNT

= 6.7E-3

The "bleed" is provided by one of two PORVs opening on demand.

o BLD1 = PV^2 + PV * BETA

= 5.52E-4

where:

PV = PORV fails to open on demand (ZIVR30 in Table 9-1)

= 4.27E-3

BETA = generic common cause beta factor (ZBGN1A in Table 9-2)

= 0.125

Although bleed is guaranteed successful if the primary system is open (RCS Condition Designator X) or for a LOCA which is not isolated, it is not credited to simplify model. The unavailability of the overall feed and bleed function is as follows:

For all supports available:

o FB1 = $OP1_{FB}$ + FD1 + BLD1

= 2.3E-3

where $OP1_{FB}$ = operator fails to maintain adequate feed/bleed flow to remove decay heat and conserve inventory including makeup to RWST

= 1.7E-3 (see Section 6.4.1)

For Train B of support systems unavailable,

o FB2 = $OP1_{FB}$ + FD2 + BLD1

= 2.3E-3

For Train A of support systems unavailable,

o FB3 = $OP1_{FB}$ + FD3 + BLD1

= 9.0E-3

For a procedure initiated event with no support systems available and with the RCS open (i.e., RCS Condition X), the operator can gravity drain the RWST into the vessel. It is very probable that the RWST is full and, if the operators properly manage the inventory, the decay heat could be removed for more than 24 hours. After 24 hours, it is assumed that either offsite power is restored or some other means is available to provide makeup. If the RWST is at a minimum level, the operators have about 6 hours to recover offsite power or provide additional makeup. The unavailability of feed and bleed cooling with no support systems available and the RCS open is dominated by operator action:

- $FB4 = OP2_{FB}$

  $= 1.8E-2$

  where:

  $OP2_{FB}$ = operator fails to align the gravity feed into the vessel or fails to control flow rate properly (see Section 6.4.1).

For procedure-initiated events with RCS Condition Y (refueling level) the time to core uncovery with no cooling is very long (72 hours, 5 days after shutdown). The feed and bleed function is long term makeup into the refueling pool.

$FB5 = 1.0E-5$

7.5.5 Overpressure Protection Systems

During RHR shutdown cooling, the RHR/RCS piping is protected from inadvertent overpressurization by one or more of the following systems (per Technical Specification 3.4.9.3):

(1) two RHR suction relief valves with setpoint of 450 psig and the suction isolation valves in both trains open, or

(2) two PORVs with a pressure setpoint that is a function of temperature, ranging from about 412 psig at 163°F to about 2385 psig at 342°F, or

(3) the RCS depressurized with a vent of 1.58 square inches or greater.

The PORV low temperature overpressure (LTOP) control logic is designed specifically to protect the reactor vessel from cold overpressurization and the potential for brittle fracture. The RHR relief valves provide this function as well as protecting the RHR piping and pump seals from overpressurization.

The RHR relief valves and PORVs have control systems with common elements. These control systems are presented below followed by a discussion of how these systems are modeled.

7.5.5.1 LTOP (FSAR, Section 5.2.2.11)

The LTOP system is comprised of two separate control channels, one to each PORV (channel 1 to PCV-456A, channel 2 to PCV-456B). An "allowable pressure" is generated for each channel from a pressure programmer based on the auctioneered-low hot leg temperature input. This allowable pressure is then compared with an actual measurement from wide range reactor coolant pressure instrumentation (PT-405 for channel 1, PT-403 for channel 2). A second low temperature auctioneer unit is used to "arm" the other channel PORVs and annunciate that the PORV is armed. The LTOP system is automatically armed when the RCS temperature decreases to 342°F. This interlock allows for test/calibration of the pressure transmitters without causing LTOP actuation.

The success criteria for LTOP is that one of two LTOP channels senses the overpressure condition and provides the proper signal to the PORV to open. One PORV is sufficient to provide pressure relief. The quantification of the PORV failing to open on demand (valve hardware failure) is included in Section 7.5.2. The control circuit is analyzed below.

The logic expression for failure of a single LTOP channel is:

$$LTOP_1 = P_{ACTUAL} + P_{ALLOW} + BS$$

where:

P_{ACTUAL} = PT = pressure transmitter PT-405 (PT-403) fails to respond given a pressure increase.

P_{ALLOW} = PP = the allowable pressure setpoint fails high. This involves either failure of the temperature auctioneer or failure of the pressure programmer. For the signal from the temperature auctioneer to fail high would require multiple failures - all four temperature transmitters or a temperature transmitter and its associated diode in the auctioneer circuit. This failure mode is neglected based on its low frequency. The pressure programmer is modeled as a signal modifier.

BS = the pressure comparator bistable fails low.

The logic expression for failure of both LTOP channels is:

$$LTOP = LTOP_1 * LTOP_2$$

Failure of the low temperature auctioneer unit used to "arm" the PORV is annunciated in the control room. Once annunciated, the operator can take corrective action. For the PORV LTOP interlock to fail undetected, two failures (low temperature auctioneer <u>and</u> alarm bistable) must both occur. The frequency of this is negligible when compared to the failure of PT, PP, or BS. This quantification of top event LT is performed in Appendix D for procedure trees 1, 5, and 6.

7.5.5.2 <u>RHR Pressure Relief (FSAR Section 7.6.2)</u>

The RHR suction valves (RC-V22 and V23 on Train A, RC-V87 and V88 on Train B) function to protect the RHR from overpressure conditions. A control interlock prevents the suction valves from opening until the RCS reaches 365 psig. This control logic also causes the suction valves to automatically reclose at 660 psig. Separate pressure transmitters (PT-403 and 405) must both be below the interlock setpoint to permit both valves in a train to be opened. Either transmitter above the 660 psig setpoint causes a suction valve in either train to close. The interlock-to-open circuitry for Train A controls is made up of a pressure transmitter (PT-405), an energize-to-open bistable (PB-405A) and a relay (K734A). The auto-close circuitry for Train A controls consists of the pressure transmitter (PT-405), a deenergize-to-open bistable (PB-405B) and a relay (K735A). Train B control circuitry is similar. This control logic is modeled in several Procedure Event Tree top events as follows:

<u>Top Event RV - (Tree 1)</u>

Operator errs by opening RHR suction valves at pressure greater than 450 psig. This failure can occur in two ways:

(1) the operator attempts to open the valves above 450 psig given proper indication ($OP1_{RV}$) and the 365 psig interlock fails to function (HW_{IL}), or

(2) the operator attempts to open the valves above 450 psig given faulty indication ($OP2_{RV}$) and the pressure transmitters have both failed high (HW_{PT}).

The operator actions are quantified in Section 6.3.

The interlock circuitry is designed to fail safe (fail to operate). There is no credible failure mode of the bistable or relay failing energized and remaining eergized until the operator action $OP1_{RV}$. Thus, the first failure mode is neglected.

The second failure mode involves failure of both pressure transmitters to operate. The failure equation is:

$$HW_{PT} = PT_{403} * PT_{405}$$

This failure is quantified in Section D.1.2.

<u>Top Event SA (All Procedure Trees)</u>

RHR suction flow is lost via valve closure. This top event depends on the success or failure of top event LT. If LT is successful, then the pressure transmitters (PT-403 and PT-405), which are used for both this and LTOP control logic, must be successful. For this condition, only the bistable and relay can fail. This logic is deenerized to operate (i.e., autoclose); thus failure of the bistable or relay to cause isolations is a credible failure. The logic is redundant with respect to closing the valves. Inadvertent closure requires only a single failure. Thus,

$$HW1_{SA} = \overline{SA}|LT = PB_{405} + RL_{K735}$$

If LT is failed, then the pressure transmitters can fail. Thus,

$$HW2_{SA} = \overline{SA}|\overline{LT} = PT_{405} + PB_{405} + RL_{K735}$$

These failures are quantified in the SA top events in Appendix D.

7.6 Other Internal Plant Initiating Events

This section describes other internal plant initiators that are analyzed as plant upset initiators during shutdown.

7.6.1 LOCA Outside Containment

Several scenarios of isolation valve failures between RCS/RHR shutdown cooling and low pressure piping outside containment have been identified.

(1) The first scenario involves check valve CBS-V26 which isolates Train 'A' (or CBS-V25 which isolates Train 'B') RHR pump suction from the CBS pump suction downstream of check valve CBS-V3. Failure of this check valve during RHR shutdown cooling would allow pressure up to 450 psig (the suction side relief valve setpoint) to enter the low pressure (300 psig design) CBS piping. This piping has been hydro tested to at least 375 psig. The CBS piping is closed inside containment by the manual isolation valve (CBS-V13, V19) and is isolated from the RWST by closed MOVs CBS-V2, V5. Thus, this piping is closed, with a 300 psig 3/4" relief valve at the heat exchanger. Based on a review of the pressure capacity of the piping, there is a high likelihood that the CBS piping will remain intact. This scenario is not considered credible.

(2) The second scenario involves MOV RH-V35 which isolates the RHR Train 'A' pump discharge from the suction side of both charging pumps. MOV failure and opening during RHR shutdown cooling would allow pressure up to 600 psig (the relief valve setpoint plus 150 psi due to the pump) to enter low pressure (220 psig design, 275 psig test) CVCS suction piping. If such a pressure caused failure of the 8-inch piping going to the charging pumps, a flow rate of 3000 gpm or more of primary inventory would be lost out the break into the charging pump cubicles. This

would cause loss of inventory in the primary system, failure of both charging pumps due to flooding, and containment bypass. However, the pressure capacity of this piping was reviewed and found to be well above 600 psig. This is not considered a credible scenario.

(3) The third scenario is similar but involves MOV RH-V36, the isolation valve between RHR pump B discharge and suction of both SI pumps. The SI piping on the suction side is also 22 psig design, 275 psig test. If it failed (in the RHR vault) the resulting flood would cause loss of both RHR pumps, SI pumps and CBS pumps, a loss of primary inventory, and containment bypass. This piping was also reviewed wi regard to its pressure capacity. It was found to be well above 600 psig. This is not considered a credible scenario.

(4) The fourth scenario involves RH-V33, the manual isolation valve between the RHR pump suction crossover line and the RWST. This 8-inch line is used to refill the RWST at the end of refueling. Valve CBS-V5 to the RWST is normally closed during shutdown cooling so that if RH-V33 failed, the water flows back to the suction of the CBS and RHR pumps. This piping is all 300 psig design piping, tested to at least 375 psig and is very likely to remain intact at RHR pressure up to 450 psig, the RHR relief valve setpoint. This scenario is not considered further.

Based on considerations of piping pressure capacity, no credible LOCA-outside containment scenarios have been identified.

7.6.2 Loss of DC Power

DC power supplies control power to all the essential ac buses, reactor trip breakers, diesel generators, and emergency power sequences (SSPSA Section D.2). It also serves as a reserve supply to the 120V ac instrument buses through the UPSs. Loss of DC power during shutdown would require restart or trip of various electrical loads but does not cause a loss of decay heat removal transient since the RHR loop will continue to operate. Loss of DC power by itself is not an initiating event during shutdown. Loss of DC power given a LOSP initiating event is a station blackout sequence because the diesels cannot start or load.

However, this is a very low frequency which is dominated by hardware loss of the diesels. Availability of DC power is not questioned in this study.

7.6.3 LOCA Due To Containment Sump Isolation Valves (LS)

A LOCA results if the sump isolation valve on the standby RHR train is opened with the associated sump isolation check valve leaking. Thus, assuming RHR train A is running, if the train B sump isolation check valve (CBS-V25) failed (gross severe leakage) while the train B containment sump valve (CBS-V14) was open for test or maintenance, the inventory of the RCS would quickly be drained via a 16-inch line to the containment sump. With the RCS water in the sump, the water level in the vessel is still several feet above the core but would require operator action within about an hour. If the LOCA to the sump occurred in the same train as the operating pump, RHR suction would automatically transfer to the sump when there was sufficient inventory. Thus, only the train B sump path is quantified (assuming RHR train A is running).

The LOCA to the sump can occur anytime throughout the shutdown. The sump valves are required to be tested once per 18 months. During Plant Condition W (RCS filled), the RCS is hot and pressurized for a short period of time just after shutdown. A LOCA to the sump is most serious during this time. However, a pre-existing failure of the check valve would be detected when the RHR System is placed in operation by the CBS Thermal Monitoring System. This situation (leaking check valve) would be remedied prior to a test of the sump valve. For this LOCA to occur, the check valve would be required to fail while the sump valve is open. This condition is very short (24 hours or less) and it is very unlikely that sump valve testing would be done during this time.

In Condition W, when the RCS temperature and pressure are low (< 200°F, < 1[illegible]0 psig), a LOCA to the sump would drain the RCS to the hot legs and would require operator action to prevent RHR pump cavitation. It would require RHR sump recirculation cooling. Also, pre-existing failures of the check valves are not detectable at low temperature and pressure. Should a LOCA of this type occur, RCS pressure, level monitors, and containment sump level alarms would aid the operator in recovery actions. This event is quantified below as the check valve fails sometime in Condition W but is not detected and the test occurs where the sump valve is opened and the operator fails to immediately reclose the valve:

$$LS = \frac{\overline{CV} * t_W}{2} * FR * NR = 2.1E\text{-}5 \text{ (mean)}$$

where $\overline{CV}$ = frequency of check valve gross leakage (ZIVCOL in Table 9-1)

= 5.36E-7/hr

t_W = time in Condition W (from Table 9-3)

= 1455 hr/yr

FR = frequency of sump valve test

= 0.67 per year

NR = probability of failing to immediately reclose sump valve (from Section 6.4)

= 0.08 (mean)

A LOCA to the sumps during Plant Condition X (drained) would result in loss of RHR pump suction but would cause loss of small amounts of inventory. The frequency of this occurrence is insignificant when compared with other vortexing initiators.

A LOCA to the sumps during Plant Condition Y (refueling) would be similar to a low pressure LOCA in Condition W except that much more time would be available to isolate the LOCA by reclosing the sump valve o the RHR suction valves. It is concluded that Condition Y is not as significant as Condition W.

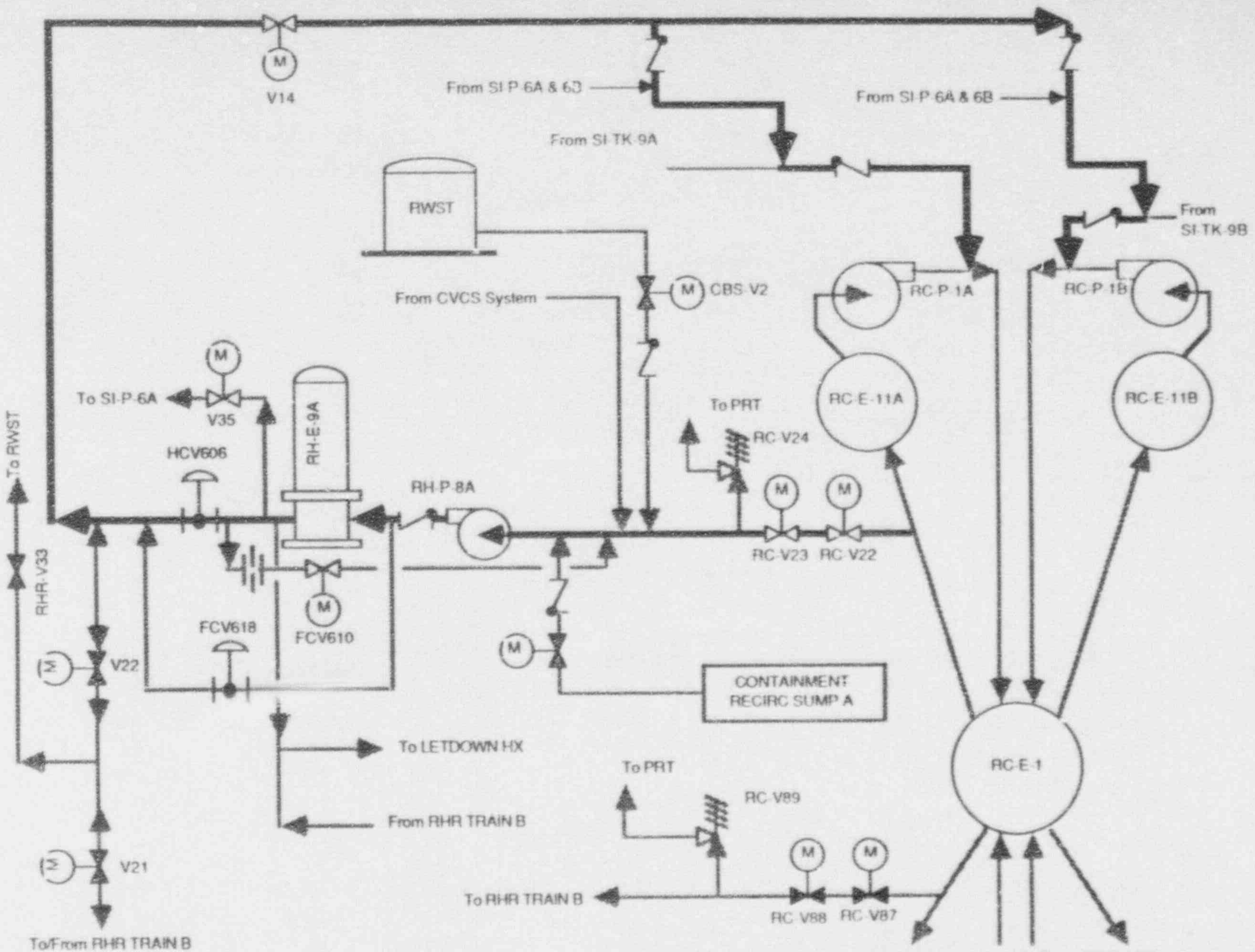


FIGURE 7-1 RHR TRAIN A

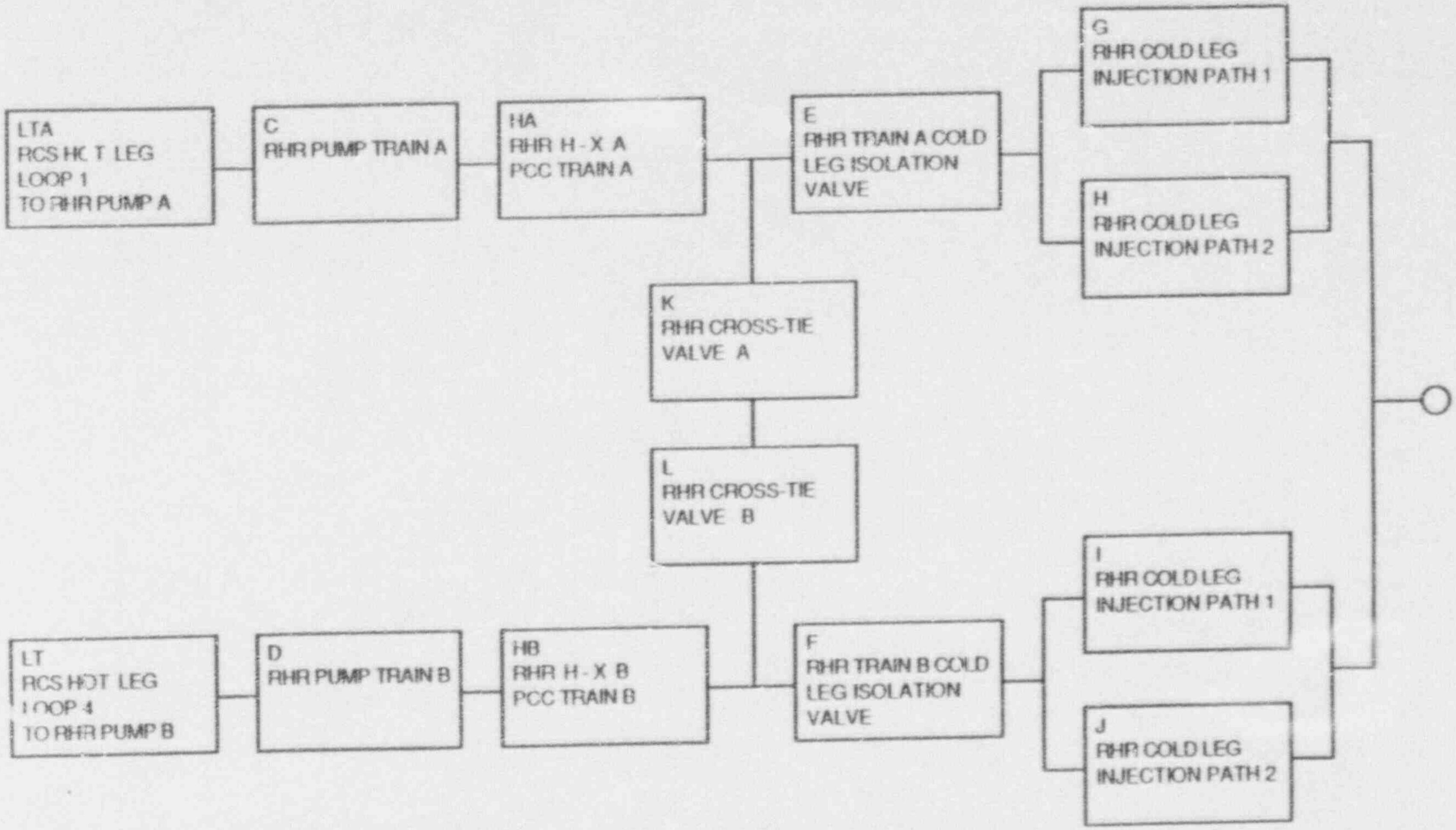


FIGURE 7-2
RHR LONG TERM COOLING LOGIC
BLOCK DIAGRAM

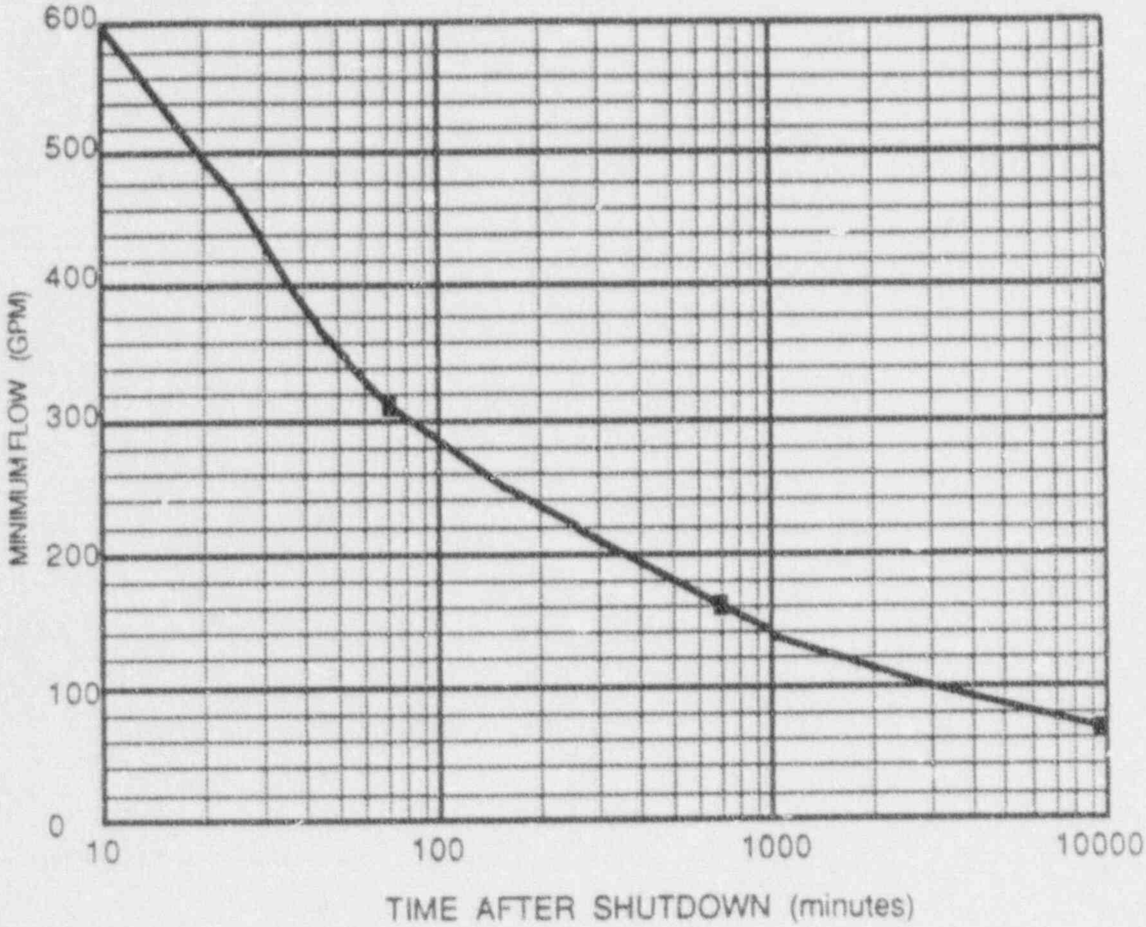


FIGURE 7 - 3

MINIMUM ECCS FLOW TO REMOVE DECAY HEAT

TABLE 7-1

SYSTEM QUANTIFICATION SUMMARY - PLANT EVENT TREE SPLIT FRACTIONS

System	System ID	Description	FREQUENCY DISTRIBUTION Mean	5th Percentile	50th Percentile	95th Percentile
RHR (Top event RR in Trans/ LOCA trees).	RR1	RHR failed given ASSA(1), RHR Trains A/B avail., and RCS Filled (W).	4.4E-4	4.2E-5	2.5E-4	1.4E-3
	RR2	RHR failed given ASSA, RHR Trains A/B avail., and RCS Drained (X).	2.3E-4	2.2E-5	1.3E-4	7.4E-4
	RR3	RHR failed given Loss of Support Train A and/or RHR Train A and RCS Filled (W).	1.2E-1	4.2E-2	1.2E-1	1.8E-1
	RR4	RHR failed given Loss of Support Train A and/or RHR Train A and RCS Drained (X).	8.9E-3	3.0E-3	7.5E-3	1.9E-2
	RR5	RHR failed given Loss of Support Train B and/or RHR Train B, RCS Drained (X) or RCS Filled (W).	9.3E-4	9.5E-5	5.4E-4	3.0E-3
	RR6	RHR failed given ASSA, RHR Trains A/B avail., and LOSP, RCS Filled (W).	2.3E-3	5.4E-4	1.8E-3	5.6E-3
	RRZ	RR6 with RCS Drained (X).	6.3E-4	6.6E-5	3.1E-4	1.8E-3
	RR7	RHR failed given Loss of Support Train A and/or RHR Train A and LOSP, RCS Filled (W).	1.2E-1	4.2E-2	1.2E-1	1.8E-1
	RRY	RR7 with RCS Drained (X).	8.9E-3	3.0E-3	7.5E-3	1.9E-2

TABLE 7-1

SYSTEM QUANTIFICATION SUMMARY - PLANT EVENT TREE SPLIT FRACTIONS

System	System ID	Description	Mean	FREQUENCY DISTRIBUTION 5th Percentile	50th Percentile	95th Percentile
	RR8	RHR failed given Loss of Support Train B and/or RHR Train B and LOSP, RCS Drained (X) or RCS Filled (W).	7.6E-3	2.3E-3	6.3E-3	1.8E-2
	RR9	RHR failed given ASSA, RHR Trains A/B avail., RHR Pump A tripped, RCS Filled (W).	3.3E-3	8.1E-4	2.6E-3	7.7E-3
	RRA	RHR failed given ASSA, RHR Trains A/B avail., RHR Pump A tripped, RCS Drained (X).	6.6E-4	1.5E-4	5.7E-4	2.2E-3
Relief Valves (Top Event VO in Trans Tree).	VO1	Failure of 2 or more relief valves to open on demand.	3.0E-6	5.0E-9	2.1E-7	9.3E-6
	VO2	Failure of 1 relief valve to open on demand.	4.3E-3	1.0E-3	3.2E-3	9.0E-3
(Top Event OC in Trans).	VC1	Failure of 1 relief valve to reclose.	2.5E-2	6.0E-3	1.8E-2	5.4E-2
Secondary Cooling (Top Event LC in Trans/LOCA trees).	SC1	Both trains of EFW or 2 ARVs fail to operate, RCS closed (RCS Condition W).	6.0E-5	7.5E-6	3.6E-5	1.6E-4
	SC2	Single train of EFW or 2 ARVs fail to operate with RCS closed (RCS Condition W).	6.0E-5	7.4E-6	3.6E-5	1.7E-4
	SC3	Trubine-driven EFW or 2 ARVs fail to operate with RCS closed (RCS Condition W).	8.7E-4	1.1E-4	5.3E-4	2.2E-3

TABLE 7-1

SYSTEM QUANTIFICATION SUMMARY - PLANT EVENT TREE SPLIT FRACTIONS

System	System ID	Description	Mean	FREQUENCY DISTRIBUTION 5th Percentile	50th Percentile	95th Percentile
Low Pressure Inj./Rec. (Top Event LC in LOCA tree).	LP1	Low Pressure Injection - ASSA and TP (pump tripped).	7.1E-3	3.9E-3	8.0E-3	1.7E-2
	LP2	Low Pressure Injection - Support Train A failed or ASSA and TP.	1.2E-1	4.7E-2	1.3E-1	1.8E-1
	LP3	Low Pressure Injection - Support Train B failed and TP.	1.2E-2	6.2E-3	1.3E-2	2.6E-2
	LR1	Low Pressure Recirculation - ASSA and TP (pump tripped).	3.0E-3	1.2E-3	2.8E-3	5.9E-3
	LR2	Low Pressure Recirculation - Support Train A failed or ASSA and TP.	1.2E-1	4.5E-2	1.2E-1	1.7E-1
	LR3	Low Pressure Recirculation - Support Train B failed and TP.	1.0E-2	4.0E-3	9.0E-3	2.1E-2
Feed and Bleed (Top Event LC in Trans/LOCA trees).	FB1	Feed and Bleed Cooling - ASSA	2.3E-3	5.1E-4	1.6E-3	6.1E-3
	FB2	Feed and Bleed Cooling - Support Train B failed.	2.3E-3	5.6E-4	1.6E-3	6.2E-3
	FB3	Feed and Bleed Cooling - Support Train A failed.	9.0E-3	3.5E-3	7.8E-3	1.9E-2
	FB4	Feed and Bleed Cooling - No Support Train available and Procedure-Initiated Event and RCS Condition X.	1.8E-2	6.6E-3	1.5E-2	3.8E-2
	FB5	Long term makeup - RCS Condition Y (Refueling).	1.0E-5	3.7E-7	3.7E-6	3.7E-5

TABLE 7-1

SYSTEM QUANTIFICATION SUMMARY - PLANT EVENT TREE SPLIT FRACTIONS

NOTES:

(1) ASSA = All Support Systems Available.

* Top Event OC includes operator action as well as hardware quantified in VC (see Appendix E.1).

** Top Event LC (alternate long term cooling) is a combination of secondary cooling (SC), low pressure injection and recirculation (LP, LR), and feed and bleed cooling (FB), as appropriate for the boundary conditions. See Section 5.0.

TABLE 7-2

SYSTEM QUANTIFICATION SUMMARY - SUPPORT SYSTEMS

System	System ID	Description	Mean	FREQUENCY DISTRIBUTION 5th Percentile	50th Percentile	95th Percentile
Diesel Generators	DG1	$\overline{DG}$ LOSP with RCS W (Filled)	4.6E-2	9.4E-3	3.4E-2	1.2E-1
	$DG1_A$	$\overline{DG}$ LOSP and Loss of Support Train B (W)	9.3E-2	1.2E-2	5.9E-2	3.0E-1
	$DG1_B$	$\overline{DG}$ LOSP and Loss of Support Train A (W)	2.6E-1	1.4E-2	2.3E-1	4.7E-1
	DG2	$\overline{DG}$ LOSP with RCS X (Drained)	1.5E-2	1.9E-3	9.1E-3	4.8E-2
	$DG2_A$	$\overline{DG}$ LOSP and Loss of Support Train B (X)	9.3E-2	1.2E-2	5.9E-2	3.0E-1
	$DG2_B$	$\overline{DG}$ LOSP and Loss of Support Train A (X)	9.3E-2	1.2E-2	5.9E-2	3.0E-1
Primary Component Cooling	PCC1	$\overline{PCC}$ ASSA with RCS W	1.1E-4	1.5E-5	7.1E-5	3.5E-4
	$PCC1_A$	$\overline{PCC}$ Loss of Support Train B (W)	1.3E-3	3.1E-4	1.0E-3	3.5E-3
	$PCC1_B$	$\overline{PCC}$ Loss of Support Train A (W)	6.1E-2	2.4E-2	5.9E-2	1.2E-1
	PCC2	$\overline{PCC}$ ASSA with RCS X	2.2E-6	1.3E-7	9.3E-7	7.7E-6
	$PCC2_A$, $PCC2_B$	$\overline{PCC}$ Loss of Single Support Train (X)	1.3E-3	3.0E-4	9.7E-4	3.4E-3
	PCC3	$\overline{PCC}$ LOSP, ASSA with RCS W	1.3E-4	2.1E-5	8.7E-5	3.6E-4
	$PCC3_A$	$\overline{PCC}$ LOSP, Loss of Support Train B (W)	1.4E-3	3.5E-4	1.1E-3	3.3E-3
	$PCC3_B$	$\overline{PCC}$ LOSP, Loss of Support Train A (W)	6.1E-2	2.4E-2	5.9E-2	1.2E-1
	PCC4	$\overline{PCC}$ LOSP, ASSA with RCS X	1.3E-5	3.4E-7	3.4E-6	5.9E-5
	$PCC4_A$, $PCC4_B$	$\overline{PCC}$ LOSP, Loss of Single Support Train (X)	1.3E-3	3.3E-4	1.0E-3	3.2E-3
Service Water	SW1	$\overline{SW}$ ASSA with RCS W	2.8E-6	1.9E-7	1.3E-6	7.7E-6
	$SW1_A$	$\overline{SW}$ Loss of Support Train B (W)	2.7E-4	3.5E-5	1.7E-4	8.5E-4
	$SW1_B$	$\overline{SW}$ Loss of Support Train A (W)	6.7E-3	2.5E-3	6.2E-3	1.2E-2
	SW2	$\overline{SW}$ ASSA with RCS X	5.9E-8	5.7E-11	8.8E-10	1.2E-8

TABLE 7-2

SYSTEM QUANTIFICATION SUMMARY - SUPPORT SYSTEMS

System	System ID	Description	Mean	FREQUENCY DISTRIBUTION 5th Percentile	50th Percentile	95th Percentile
	$SW2_A$, $SW2_B$	$\overline{SW}$|Loss of Single Support Train (X)	2.5E-4	3.2E-5	1.3E-4	7.8E-4
	SW3	$\overline{SW}$|LOSP, ASSA (W)	3.4E-3	1.7E-3	3.2E-3	5.9E-3
	$SW3_A$	$\overline{SW}$|LOSP, Loss of Support Train B (W)	1.9E-2	9.7E-3	1.8E-2	3.3E-2
	$SW3_B$	$\overline{SW}$|LOSP, Loss of Support Train A (W)	7.9E-2	4.1E-2	7.6E-2	1.2E-1
	SW4	$\overline{SW}$|LOSP, ASSA (X)	1.1E-3	4.0E-4	9.5E-4	2.3E-3
	$SW4_A$, $SW4_B$	$\overline{SW}$|LOSP, Loss of Single Support Train (X)	1.9E-2	9.7E-3	1.8E-2	3.3E-2

TABLE 7-3

SYSTEM QUANTIFICATION SUMMARY - PROCEDURAL EVENT TREES

Event Tree	Top Event	Split Fraction	Description	Mean	FREQUENCY DISTRIBUTION 5th Percentile	50th Percentile	95th Percentile
Tree 1	RI	RI1	Failure of both RHR pumps o start (manual start).	4.2E-4	6.5E-5	3.2E-4	1.9E-3
Tree 1	RM	RM1	RHR Train A fails to run for T_M = 295 hr	1.1E-2	6.0E-4	5.0E-3	3.9E-2
		RM2	RHR Train A fails to run for T_M = 31 hr	1.2E-3	7.8E-5	6.0E-4	4.2E-3
		RM3	RHR Train A fails to run for T_M = 50 hr	1.9E-3	1.6E-4	1.0E-3	6.6E-3
Tree 2	RM	RM4	RHR Train A fails to run for T_M = 959 hr	3.7E-2	3.3E-3	2.0E-2	1.3E-1
		RM5	RHR Train A fails to run for T_M = 47 hr	1.8E-3	1.3E-4	1.0E-3	6.3E-3
Tree 3	RM	RM6	RHR Train A fails to run for T_M = 161 hr	6.3E-3	5.7E-4	3.5E-3	2.2E-2
Tree 4	RM	RM7	RHR Train A fails to run for T_M = 1440 hr	5.6E-2	5.2E-3	3.2E-2	1.9E-1
Tree 5	RM	RM8	RHR Train A fails to run for T_M = 101 hr	3.9E-3	2.9E-4	2.0E-3	1.4E-2
		RM9	RHR Train A fails to run for T_M = 193 hr	7.5E-3	4.4E-4	4.0E-3	2.7E-2
Tree 6	RM	RMA	RHR Train A fails to run for T_M = 24 hr	9.3E-4	8.7E-5	5.3E-4	3.1E-3
		RMB	RHR Train A fails to run for T_M = 72 hr	2.8E-3	2.7E-4	1.6E-3	9.5E-3

TABLE 7-4

SYSTEM QUANTIFICATION SUMMARY - INITIATING EVENTS

Initiating Event	Description	FREQUENCY DISTRIBUTION (per year) Mean	5th Percentile	50th Percentile	95th Percentile
LOSP(X)	Loss of Offsite Power	3.0E-2	3.1E-3	1.6E-2	8.8E-2
LOSP(W)		2.7E-2	2.2E-3	1.2E-2	7.4E-2
LPCCA(X)	Loss of PCC Train A	2.9E-3	2.1E-4	1.5E-3	1.0E-2
LPCCA(W)		2.9E-3	1.7E-4	1.3E-3	1.1E-2
LPCC(X)	Loss of Both Trains of PCC	3.5E-7	6.4E-9	9.3E-8	1.5E-6
LPCC(W)		1.5E-5	3.3E-7	4.3E-6	7.3E-5
LSWA(X)	Loss of SW Train A	3.0E-4	1.7E-5	1.5E-4	1.1E-3
LSWA(W)		3.1E-4	1.5E-5	1.4E-4	1.2E-3
LOSW(X)	Loss of All Service Water	3.8E-8	2.1E-9	1.7E-8	1.4E-7
LOSW(W)		1.7E-7	9.6E-9	7.7E-8	6.2E-7
LS(W)	LOCA Through Sump Isolation Valves	2.1E-5	6.0E-7	6.5E-6	7.2E-5

TABLE 7-5 RHR COMPONENT DESCRIPTIONS

BLOCK	COMPONENT	DESCRIPTION	STATUS
LTA[(a)]	RC-V22	MOV, RHR Pump Suction Valve	Open
	RC-V23	MOV, RHR Pump Suction Valve	Open
C	RH-P-8A	RHR Pump A	Standby/Run
	CC-V455	Manual Valve, Pump Cooling	Open
	CC-V458	Manual Valve, Pump Cooling	Open
	RH-V4	Check Valve	Open
	RH-V9	Manual Valve	Open
	RH-E-9A	RHR Heat Exchanger	-----
	RH-V18	Manual Valve	Open
	RH-HCV-606	AOV	Open
HA	CC-V131	Manual Valve, RHR Hx Cooling	Open
	CC-V145	MOV, RHR Heat Exchanger Cooling	Closed/Open
E	RH-V14	MOV	Open
K[(b)]	RH-V22	MOV Cross Tie Line	Open
	RH-V33	Manual Valve to RWST	Closed
G	RH-V15	Check Valve to Cold Leg Injection	Open
	RH-V59	Manual Valve	Open
	SI-V5	Check Valve	Open
H	RH-V31	Check Valve to Cold Leg Injection	Open
	RH-V61	Manual Valve	Open
	SI-V20	Check Valve	Open

Notes:

(a) Block LTA is not included in the model because the RHR pump suction MOVs are handled separately by the Procedural Event Trees, top event SA.

(b) Block K is not included in the model because the position of the cross tie valve RH-V22 does not effect system performance unless RH-V33 is open and this situation is modeled explicitly in Procedural Event Tree 4, top event CD.

TABLE 7-6 UNAVAILABILITY EXPRESSIONS FOR TRANSIENT/LOCA
TOP EVENT RR "RHR RESTORED"

OPERATING PUMP RHR	STANDBY RHR PUMP	SUPPORT TRAIN A	SYSTEMS TRAIN B	UNAVAILABILITY EXPRESSION	FAILURE SPLIT FRACTION
Y	Y	Y	Y	$RHA_R * (RHB_S + RHB_R + RHB_M)$	RR1, RR2 (1)
		N	Y	$(RHB_S + RHB_R + RHB_M)$	RR3, RR4 (1)
		Y	N	RHA_R	RR5
		(2) Y	Y	$(RHA_S + RHA_R) * (RHB_S + RHB_A + RHB'_M)$	RR6
		(2) N	Y	$(RHB_S + RHB_R + RHB'_M)$	RR7
		(2) Y	N	$(RHA_S + RHA_R)$	RR8
Y	N	Y	Y	RHA_R	RR5
		N	Y	1.0	RRF
		Y	N	RHA_R	RR5
		(2) Y	Y	$(RHA_S + RHA_R)$	RR8
		(2) N	Y	1.0	RRF
		(2) Y	N	$(RHA_S + RHA_R)$	RR8
A (3)	Y	Y	Y	$(RHA_S + RHA_R) * (RHB_S + RHB_R + RHB_M)$	RR9, RRA (1)
		N	Y	$(RHB_S + RHB_R + RHB_M)$	RR3, RR4 (1)
		Y	N	$(RHA_S + RHA_R)$	RR8
A (3)	N	Y	Y	$RHA_S + RHA_R$	RR8
		N	Y	1.0	RRF
		Y	N	$RHA_S + RHA_R$	RR8
A (4)	Y	Y	Y	$RHB_S + RHB_R + RHB_M$	RR3, RR4
		N	Y	$RHB_S + RHB_R + RHB_M$	RR3, RR4
		Y	N	1.0	RRF
A (4)	N	Y	Y	1.0	RRF
N	Y	Y	Y	$RHB_S + RHB_R + RHB_M$	RR3, RR4
		N	Y	$RHB_S + RHB_R + RHB_M$	RR3, RR4
		Y	N	1.0	RRF

TABLE 7-6 UNAVAILABILITY EXPRESSIONS FOR TRANSIENT/LOCA
TOP EVENT RR "RHR RESTORED"

OPERATING PUMP RHR	STANDBY RHR PUMP	SUPPORT TRAIN A	SYSTEMS TRAIN B	UNAVAILABILITY EXPRESSION	FAILURE SPLIT FRACTION
		(2) Y	Y	$RHB_S + RHB_R + RHB'_M$	RR7
		(2) N	Y	$RHB_S + RHB_R + RHB'_M$	RR7
		(2) Y	N	1.0	RRF
N	N	Y	Y	1.0	RRF

Notes:

Y = Yes, train is operable.
N = No, train is unavailable.
A = Train is available if operator action to trip the pump
(1) = The split fraction depends on the value of RMB_M which is dependent on the RCS conditions.
(2) = For LOSP and assumed for all other internal/external initiators.
(3) = For top event TP (pump trip) successful. (Procedure Initiated Events only).
(4) = For top event TP failed. (Procedure Initiated Events only).

For quantification of the unavailability expressions, see Section 7.1.3.

TABLE 7-7

ELECTRIC POWER RECOVERY MODEL

Recoverability (a)					Electric Power Unavailability		
Offsite Power	Both Diesels	Single Diesel	RCS (b) Condition	Initiating Events	With Recovery (Section 7.2.4) (c)	Without Recovery (Section 7.2.2) (d)	Electric Power Recovery Fraction (e)
*			W	LOSP(W)	EPR11 = 7.85E-2	DGF = 1.0	ER1 = 7.9E-2
*		*	W	LOSP(W)	EPR12 = 6.12E-3	$DG1_B$ = 2.6E-1	ER2 = 2.4E-2
*	*		W	LOSP(W)	EPR13 = 4.17E-4	DG1 = 4.6E-2	ER3 = 9.1E-3
		*	W	FLISG(W)	EPR14 = 9.21E-2	$DG1_B$ = 2.6E-1	ER4 = 3.4E-1
	*		W	TCTL(W),FTBLP(W)	EPR15 = 1.28E-2	DG1 = 4.6E-2	ER5 = 2.7E-1
*			X	LOSP(X)	EPR16 = 1.27E-1	DGF = 1.0	ER6 = 1.3E-1
*		*	X	LOSP(X)	EPR17 = 2.18E-3	$DG2_B$ = 9.3E-2	ER7 = 2.3E-2
*	*		X	LOSP(X)	EPR18 = 1.62E-4	DG2 = 1.5E-2	ER8 = 1.1E-2
		*	X	FLISG(X)	EPR19 = 3.51E-2	$DG2_B$ = 9.3E-2	ER9 = 3.8E-1
	*		X	TCTL(X),FTBLP(X)	EPR20 = 4.00E-3	DG2 = 1.5E-2	ER0 = 2.7E-1

(a) An " * " in the columns indicates the equipment is recoverable.

(b) RCS Condition designators are defined as follows:

W = RCS filled, secondary cooling available.
X = RCS drained to vessel flange or hot leg mid-plane.

(c) Electric power unavailability with recovery models failure of diesel generators to operate while offsite power is unavailable and recovery of diesels and offsite power.

(d) Electric power unavailability without recovery models failure of the diesel generators to start and operate for 24 hours.

(e) The recovery fraction is equal to

$$EF = \frac{EP(W/\ REC)}{EP(W/O\ REC)} = \frac{\text{Column 6}}{\text{Column 7}}$$

8.0 EXTERNAL EVENTS AND INTERNAL HAZARDS ANALYSIS

This section is based on a review of SSPSA Section 9, "External Events Analysis" (Reference 1) for the application of those events to shutdown conditions. Also, events that could occur only at shutdown are considered.

The so called "external events" have been divided into two groups - events initiated outside the physical plant (external events, Section 8.1) and events initiated inside the physical plant but ou' 'de the power production cycle (internal hazards, Section 8.2). These events were reviewed to determine if their impact on the plant during shutdown was more or less likely or severe than that analyzed in the SSPSA with the plant at power. Where no differences were identified (i.e., the hazards are uniformly likely throughout the year), the annual frequencies of the initiating events from the SSPSA were multiplied by the fraction of time the plant is expected to be in shutdown. From Section 9.2, this shutdown fraction [FR(SD)] is equal to 0.37. Note that the frequencies used in the SSPSA were not multiplied by a non-shutdown fraction [1-FR(SD)] and include the conservative assumption that the plant is at power for the full year.

Also, the initiating events are qu ntified for two possible conditions of the reactor coolant systems:

Condition X - RCS drained to the vessel flange or hot leg mid-plane

Condition W - RCS filled and closed; secondary cooling available.

Condition Y was not explicitly modeled for because of the short duration of this condition (about 4% of the average annual time in shutdown) and because of the long time (> 72 hours) available with no active decay heat removal. This information is used in the subsequent quantification of operator response to the initiators.

A summary of external and internal hazard initiating events at shutdown is given in Table 8-1 (uncertainty distributions) and in Table 8-2 (plant impacts). These initiating events are included in the plant model described in Section 3 and quantified in Section 5.

8.1 External Events

The following external events have been analyzed for their impact on the plant at shutdown:

- seismic events
- aircraft crash
- rnal flood
- ardous chemicals and transportation events
- wind and tornado missiles
- turbine missiles

These events are discussed in the following sections.

8.1.1 Seismic Events

This analysis of seismic initiated sequences is based on a review of the SSPSA (Reference 1), Section 9.2 and an updated analysis of equipment fragilities in Reference 9. Based on these documents, a relatively limited number of seismically sensitive components were found to be important to risk: offsite power, RWST, reactor internals (control rods), diesel generators, and steam generator and reactor coolant pumps (LOCA initiators).

From these component failures, there are three general seismic sequences in the SSPSA: station blackout, ATWS, and large LOCA. For station blackout, the seismic failure of offsite power and of diesels is not affected by the shutdown configuration. However, for smaller earthquakes, where offsite power failure is still likely, increases maintenance unavailability of the diesels during shutdown could be important. This is evaluated below. The ATWS sequences (reactor internals) are clearly not applicable during shutdown modes. The LOCA sequences are dominated by seismic failure of steam generators or reactor coolant pumps. Seismic failure of the RWST is not modeled because no credit is given to operators manually initiating low pressure injection.

In addition, the following potential seismic initiated sequences, which are unique to shutdown, have been considered:

(1) Equipment hatch in its storage position falls off, causing damage to components in its vicinity and deforming the hatch so that it cannot be reinstalled. Based on a review of the containment layout, there are no critical components within one diameter from the equipment hatch storage rack. Also, deformation of the hatch is not important because the seismic event is very likely to cause loss of offsite power. Since the polar crane is powered from Bus 11 (i.e., non-essential power), the crane cannot be operated without offsite power.

(2) Containment polar gantry crane, trolley, or a load falls, damaging components or fuel. The crane bridge and trolley are equipped with earthquake restraints (up-kick lugs) which are designed to prevent the crane from overturning and leaving the rails during an earthquake. (Reference 10, p. 44). Also, seismic fragility of the crane anchor bolts is very high (median capacity of

about 1.75 g). If the crane did leave its rails during an earthquake, it would most likely impact the sides of the containment but is not likely to impact any of the components. If the trolley were to fall despite the restraints, it might impact the steam generators or pressurizer causing a LOCA or if the vessel head were off during refueling, cause fuel-cladding damage. Since the location of this impact is at the high point in the RCS, the resulting LOCA would be less severe than the LOCA assumed to result from steam generator or reactor coolant pump support failures. Fuel-cladding damage might result from impact of heavy objects such as the trolley dropping into the vessel, but fuel overheating is very unlikely. The likelihood of a load falling is very small because the crane is not in operation for much of the time in shutdown. The consequences of a load falling are similar to the trolley case and are covered by the discussion above. Seismic failure of the polar crane or its loads is not considered further.

(3) The refueling cavity seal ring fails causing loss of inventory over the vessel during refueling. This ring is a 2-3/8 inch steel plate, 3-1/2 feet wide, fastened on the outside to the biological shield wall and on the inside to the vessel flange, using 36, 3/4 inch bolts on each wall. The seal ring is tested using compressed air prior to its use and leakage is monitored as the

refueling pool is filled. The only seismic failure mode that is considered is differential movement of the vessel and biological wall. However, the vessel is supported by the nozzles on the same concrete wall. If differential motion resulted in bolts shearing off, the weight of the water on the ring would act to keep it in place. If a large leak developed, water would drain down to the top of the vessel flange, leaving about 12 feet of water over the core. If a spent fuel assembly was being transferred at this time, there would be a high radiation field in the area. Special shielding would be required to manually lower the assembly into the water in the vessel or in the refueling canal. This might result in worker exposure but does not pose a risk to the general public.

The seismic seal failure is judged to be bounded by the steam generator LOCA in both fragility and consequences of failure. The steam generator failure is assumed to cause a large LOCA at the cold leg connection and would drain the refueling pool down to the bottom of the cold legs, which is about 7 feet above the top of the core. The steam generator failure gives the operator less time to respond. The steam generator LOCA event is addressed below and is judged to have a higher frequency and more severe consequences. The cavity seal ring failure is only applicable during refueling while the steam generator failure is applicable throughout the shutdown. The cavity seal ring failure is not considered further.

(4) Steam generator nozzle dams fail causing loss of coolant inventory in the vessel. The nozzle dams are aluminum plates which are installed to allow access to the steam generators for surveillance and maintenance and are bolted onto the steam generator interior surface. Seismic failure of the nozzle dams is much less likely than the steam generator failure which is discussed above. Nozzle dam failure is applicable only when installed during steam generator maintenance. The nozzle dams are not evaluated further.

The seismic sequences important at shutdown are (1) loss of cooling due to seismic loss of offsite power and seismic or non-seismic failure of diesel generators and (2) loss of coolant inventory (LOCA) due to seismic failure of the steam generator or reactor coolant pump supports. It is assumed that these sequences lead to core damage with no operator recovery. The following Boolean equations can be written for a seismic station blackout (SSBO) and a seismic large LOCA (SLL):

SSBO(X) = [FR(SD][FR(X)][(SS)(OSP * DG(X)]

SSBO(W) = [FR(SD)][FR(W)][(SS)(OSP * DG(W)]

SLL(W) = [FR(SD)][FR(W)][(SS)(LL)]

where:

"*" is used for AND logic

SS = annual seismic hazard frequency.

FR(X) = fraction of shutdown in RCS Condition X - RCS drained.

= 0.51 (mean) - from Table 9-3.

FR(W) = fraction of shutdown in RCS Condition W - RCS filled

= 0.45 (mean) - from Table 9-3

FR(SD) = fraction of the year in shutdown

= 0.37 (mean) - from Table 9-3

OSP = seismic failure of offsite power

= 0.5 (at 0.30g) - from Reference 9

DG(W) = seismic or non-seismic failure of both diesel generators in RCS Condition W

= DGAB or DGAB'(W)

DG(X) = DGAB or DGAB'(X)

DGAB = seismic failure of both diesel generators

= 0.5 (at 1.51g) - from Reference 9

DGAB'(W) = non-seismic failure of both diesel generators, no recovery (includes extended shutdown maintenance) in RCS Condition W

= 4.6E-2 (mean) - DG1 in Section 7.2.2

DGAB'(X) = non-seismic failure of both diesel generators, no recovery - RCS Condition X

= 1.5E-2 (mean) - DG2 in Section 7.2.2

LL = seismic initiated large LOCA = SG or RCP

SG = seismic failure of steam generator supports, causing a large LOCA

= 0.5 (at 1.71g) - from Reference 9

RP = seismic failure of reactor coolant pump supports, causing a large LOCA

= 0.5 (at 1.74g) - from Reference 9

These expressions are quantified using the SEIS4 computer code (Reference 14). The SEIS4 program combines seismic fragility curves for equipment and structures (Reference 9) according to the specified logic (i.e., as above). It then assembles this resulting fragility with seismic hazard curves (Reference 1, SSPSA Se[illegible] 9.2) to provide the frequency of occurrence. SEIS4 is a probabilistic calculation program which expresses fragility families, seismic hazard distribution and the resulting frequency of occurrence in the form of a discrete probability distribution. The results are as follows:

SSBO(X) = 3.1E-6 (mean)
SSBO(W) = 2.3E-6 (mean)
SLL(W) = 3.8E-7 (mean)

The distributions for these initiating events are given in Table 8-1.

8.1.2 Aircraft Crash

Based on a review of SSPSA, Section 9.3, no unique shutdown initiators have been identified. No sequences have been identified that would significantly increase the frequency or consequences of the aircraft crash initiators during shutdown. The frequencies of initiators quantified in the SSPSA are 10^{-7} per year and less (less than 10^{-8} per year for initiators which fail containment) and are judged to be insignificant contributors to the shutdown risk.

8.1.3 External Floods

Based on a review of SSPSA, Section 9.6, no external flood initiators unique to shutdown have been identified. The following initiator is quantified:

FLSW - external flood of the service water pumphouse and cooling tower pump switchgear room causing loss of all service water. The flood is likely accompanied by a storm and high wind causing a loss of offsite power. Loss of service water causes failure of the diesel generator due to overheating.

FLSW(X) = FLSW' * FR(SD) * FR(X)
= 3.0E-7 (mean)

FLSW(W) = FLSW' * FR(SD) * FR(W)
= 2.7E-7 (mean)

where,

FLSW' = frequency of external flood causing loss of all service water, from SSPSA

= 1.60 E-6/yr

FR(SD) = shutdown fraction = 0.37 (from Table 9-3)

FR(X) = fraction of shutdown in RCS Condition X - drained

= 0.51 (from Table 9-3)

FR(W) = fraction of shutdown in RCS Condition W - full

= 0.45 (from Table 9-3)

8.1.4 Hazardous Chemicals and Transportation Events

Based on a review of SSPSA, Section 9.7, no unique shutdown initiators have been identified. The following initiator is quantified during shutdown:

TCTL - truck crash into the SF_6 transmission lines causing a non-recoverable loss of offsite power. It is likely that the frequency of truck traffic will increase during shutdown due to maintenance and repairs. However, the frequency assumed in SSPSA Table 9.7-3 is judged to be sufficiently conservative at power to cover shutdown conditions.

TCTL(X) = TCTL' * FR(SD) * FR(X)

= 5.1E-5/yr

TCTL(W) = TCTL' * FR(SD) * FR(W)

= 4.6E-5/yr

where,

TCTL' = frequency of truck crash into transmission lines, from SSPSA = 2.76 E-4/yr

FR(SD) = shutdown fraction = 0.37 (from Table 9-3)

FR(X) = fraction of shutdown in RCS Condition X - drained

= 0.51 (from Table 9-3)

FR(W) = fraction of shutdown in RCS Condition W - full

= 0.45 (from Table 9-3)

8.1.5 Wind and Tornado Initiated Scenarios

Based on a review of SSPSA, Section 9.8, no unique shutdown initiators have been identified. The initiating events quantified in the SSPSA are negligible based on the following:

The event MPCC, tornado missiles causing loss of Primary Component Cooling (PCC), is much lower frequency (5.46 E-9/yr) than other external and internal events causing loss of PCC, e.g., FPCC*. Similarly, event MCR, tornado missiles impacting the control room are much lower in frequency (5.80 E-9) than other similar initiators, such as FCRAC*. Finally, event MELP, missile causing non-recoverable station blackout (3.4 E-10) is much lower in frequency than events such as FCRAC*.

While more missile sources may be present in shutdown than during operation, the spectrum of missiles used in Case 1 of the SSPSA analysis, one unit operating and the other unit under construction, is judged to be sufficiently conservative to cover the shutdown case. No wind or tornado initiators are quantified for the shutdown study.

8.1.6 Turbine Missile Hazards

The main turbine is not operating at high speed during shutdown so this event is therefore not capable of generating a missile.

8.2 Internal Hazards Analysis

The following internal hazards have been analyzed for their effect on the plant at shutdown:

- o fires
- o floods
- o heavy loads

8.2.1 Fire Analysis

8.2.1.1 Introduction

Fires are analyzed as sources of plant upset initiators during shutdown, including loss of decay heat removal (RHR and Support Systems) and LOCAs. Overpressurization is not considered a significant event because it requires multiple failures - an overpressure source (caused by a hot short) and the isolation of relief paths (also caused by hot shorts). Recriticality is also not considered because of the slow nature of such an event, the redundant operator alarms, and the minor consequences. (See Section 3.2.5).

Critical fire scenarios were identified by, first, identifying what component failures (or actions for hot shorts) would cause failure of the operating RHR train or would cause a LOCA. Then, the fire areas were identified which contain these components or related cable by reviewing the Seabrook Station Fire Protection Report (Reference 16). Fire scenarios in these areas were quantified by using models and data from the fire analysis in SSPSA Section 9.4. These models are judged to be applicable because requirements for fire detection and suppression

---

* Fire initiators - see Section 8.2.1.

systems are essentially the same at shutdown as at power (Reference 15, Technical Requirements 7 through 12). In addition, shutdown-specific fire initiating frequencies were developed from review of industry data, as discussed in Section 8.2.1.4 and Appendix D. Based on this analysis, the critical fire scenarios were quantified, as listed in Tables 8-1 and 8-2.

The fire analysis was simplified somewhat by making the following assumptions:

- o Loss of ventilation due to fire is assumed to not cause loss of decay heat removal (i.e., EAH, PAH, SWA). The operator has time to respond to the loss of ventilation. Also, the fire serves as the alarm to alert the operators to provide some alternate ventilation system (e.g., open doors and fans).
- o Fire in an RHR vault would not propagate to the opposite train vault (SSPSA p. 9.4-4).
- o Fire in the essential switchgear room would not propagate to the opposite switchgear room (SSPSA p. 9.4-5 and pp. 9.4-13, 14).
- o Fire in the battery rooms is assumed not to cause loss of dc voltage from the inverters because of the additional ac feed.
- o Fire in the diesel generator building can affect one diesel only (SSPSA p. 9.4-7).
- o Fires affecting buried duct banks are assumed to be negligible frequency because of the lack of combustibles.

8.2.1.2 Fire - Induced LOCA Initiators

Potential LOCA initiators were identified and analyzed below. These LOCAs were identified by looking at high pressure - low pressure interfaces which could be breached by hot shorts in control cables causing repositioning of valves (Reference 16). Based on this analysis, no fire-induced LOCAs were identified which are critical fire scenarios.

1. Excess Letdown Line LOCA (Reference 16, p. 3.5-2)

Requires hot shorts of three valves:

CS-HCV-123 (excess let. HX outlet block) - transfer closed

CS-V175 (excess let. HX inlet block) - transfer closed

CS-V176 (excess let. HX inlet block) - transfer closed

Loss of reactor coolant is through 1" line back to VCT. In order to be lost to the CVCS, CS-V170 (divert valve to RCDT) must transfer (hot short), providing flowpath to RCDT (reactor coolant drain tank). To get outside containment, CS-FV-1403 (isolation valve between RCDT and PDT) must fail open (hot short) providing flowpath from RCDT to PDT (primary drain tank - outside containment).

In addition, the line is restricted to a maximum flow of 25 gpm. At low pressure, the flow rate would be much smaller. The LOCA would be accompanied by alarms (level in RCDT or PDT). Thus, this LOCA is considered to be negligible in frequency (requiring multiple hot shorts) and in consequences.

2. Normal Letdown Line LOCA (Reference 16, p. 3.5-2)

Requires hot shorts of three valves:

CS-V145 (regen. HX outlet block)

RC-LCV-459 (regen. HX inlet block)

RC-LCV-460 (regen. HX inlet block)

Loss of reactor coolant is restricted to a maximum of 120 gpm. The flow is back to the VCT and if unattended (VCT high level alarms ignored), the excess would discharge to the PRT through a 60 psig relief valve. This path is isolated when the RHR is used for letdown (when the RCS is depressurized). Thus, this LOCA is considered to be negligible in frequency, requiring multiple hot shorts and operator failure.

3. Accumulator Drain Lines LOCA

This requires a hot short of three valves:

SI-V4 (or V18, V33, V48 - accumulator drain lines) - transfer open

SI-V70 (common drain line isolation) - transfer open

SI-V62 (common drain line isolation) - transfer open

Loss of reactor coolant is through a 3/4" dia. line to the RWST. The LOCA is considered to be negligible in frequency (requiring multiple hot shorts) and insignificant in consequences.

4. High Pressure Recirculation Suction Line LOCA

This requires a hot short of RH-V36 (from RHR pump B discharge to SI pumps suction) or multiple hot shorts (RH-V35 and CS-V475 and CS-V460 or V461 - from RHR pump A discharge to SI pumps suction).

Based on piping analysis documented in Section 7.6.1, piping failures at RHR pressures (450 psig) are not credible for the SI suction piping.

5. Test Line from RHR Discharge Line LOCA

This requires hot short of RH-V28 (isolates test line). This provides potential pressurization (up to 600 psig) of the test line piping. However, this piping is all high pressure tested (per PID-SI-D20446, Rev. 2). Thus, this is not a credible scenario.

8.2.1.3 Fire-Induced Loss of RHR Initiators

The following fire scenarios resulting in potential loss of RHR were identified and analyzed. These fires were identified by determining the components whose loss (or activation for hot shorts) would result in loss of the operating RHR train (assumed to be train A). These components are listed in Table 8-3 with the failure mode and fire zone/area for each component. The potential critical fire scenarios are quantified below and are listed in Tables 8-1 and 8-2. The frequency of a fire in a particular location failing critical cables or components was quantified using applicable models from the SSPSA Section 9.4, as referenced below.

(1) Switchgear Room A (CB-F-1A-A)

This area is considered for a fire causing loss of train A of RHR due to loss of AC essential power. This scenario is analyzed in SSPSA §D.2.3.4.1. The frequency of a fire in the siwtchgear room causing loss of essential power during shutdown is:

$$FSGA(X) = FR(SD) * FR(X) * f_{AUX,SD} * f_{SGR} = 2.5E-3 \text{ (mean)}$$

$$FSGA(W) = FR(SD) * FR(W) * f_{AUX,SD} * f_{SGR} = 2.3E-3 \text{ (mean)}$$

where:

FR(SD) = shutdown fraction

= 0.37 (from Table 9-3)

FR(X) = fraction of shutdown in RCS Condition X - drained

= 0.51 (from Table 9-3)

FR(W) = fraction of shutdown in RCS Condition W - full

= 0.45 (from Table 9-3)

$f_{AUX,SD}$ = frequency of fires in the PAB during shutdown, from Table 8-4

= 7.2E-2/yr (mean)

f_{SGR} = fraction of fires in the PAB that may occur in the switchgear room, from SSPSA, p. D.2-43

= .190 (mean)

(2) Cable Spreading Room (CB-F-2A-A)

This area is considered for a fire causing loss of 2 trains of support systems (AC essential power, PCC, or service water) and loss of both trains of RHR (directly or indirectly through support systems). This scenario is analyzed in SSPSA §9.4.6. In that analysis, the time available to respond to the fire including actions at the Remote Safe Shutdown Panel (RSSP) is 2 hours (minimum time to core melt at power). This time is conservative for accidents at shutdown. The operator failure to maintain decay heat removal from the remote safe shutdown panel, given at least 2 hours, is estimated in Section 6.4:

$$f_{HE,2} = 4.3E-3 \text{ (mean)}$$

Two critical fire scenarios are modeled - loss of two trains of support systems with no loss of offsite power (i.e., loss of PCC) and loss of two trains of support systems with loss of offsite power (i.e., loss of essential AC trains A and E). These are quantified as follows:

Frequency of cable spreading room fire during shutdown causing loss of PCC (FSRCC') is quantified assuming a short time (2 hours) to core uncovery, i.e., the RCS is drained down soon after shutdown.

$FSRCC' = FR(SD) * f_{CSR,SD} * Q_{PCC,CSR} * f'_{HE,2} = 2.1E-8$ (mean)

where:

$FR(SD)$ = 0.37 (from table 9-3)

$f_{CSR,SD}$ = frequency of cable spreading room fires during shutdown, from Section 8.2.1.4

= 5.6E-3/yr (mean)

$Q_{PCC,CSR}$ = conditional frequency of loss of PCC given a fire in the cable spreading room (includes fire propagation and suppression and fire severity), from SSPSA p. 9.4-26

= 2.4E-3 (mean)

$f'_{HE,2}$ = conditional frequency of operator error, failing to successfully establish shutdown cooling from the RSSP, from Section 6.4

= 4.3E-3 (mean)

The frequency of the cable spreading room fire during shutdown causing loss of all AC power is quantified assuming a short time (2 hours) to core uncovery. Availability of the turbine-driven EFW pump is not included in the quantification because it is assumed the RCS is drained down.

$FSRAC' = FR(SD) * f_{CSR,SD} * Q_{EP,CSR} * f'_{HE,2} = 1.1E-8$

where:

$FR(SD)$ = 0.37 (from Table 9-3)

$f_{CSR,SD}$ = 5.6E-3/yr (mean) - above

$Q_{EP,CSR}$ = conditional frequency of loss of all AC power, given a fire in the cable spreading room, from SSPSA p. 9.4-2

= $(1/2) * Q_{PCC,CSR}$ = 1.2E-3 (mean)

$f'_{HE,2}$ = 4.3E-3 (mean) - above

The frequencies of these fires are so low that they do not make a significant contribution to the risk at shutdown. Thus, these scenarios are not included in the plant model.

Fires in the cable spreading room causing only loss of RHR are judged to be similar to the above scenarios with regard to frequency but much less severe because of the availability of support systems. Thus, fire causing only RHR loss is not quantified.

(3) Control Room (CB-F-3A-A)

This area is considered for a fire causing loss of 2 trains of support systems and loss of both trains of RHR. This scenario is analyzed in SSPSA §9.4.7. The operator action analysis is similar to the cable spreading room scenarios. Because of the uncertainty of the plant configuration at shutdown, it is conservatively assumed that the RCS is drained down early in the outage - with about 2 hours to core uncovery, given loss of cooling. Thus, the human error frequency $f'_{HE,2}$ from Section 6.4 is used in this quantification.

Fire scenarios are considered in each zone of the main control board. The following zones are of importance:

- Zone C - Loss of PCC
- Zone G - Loss of Service Water and Cooling Tower
- Zone H - Station Blackout (LOSP and loss of power to buses E5 and E6
- Zones A and B - Loss of RHR

A fire causing loss of RHR would require hot shorts in a single zone (B) or a fire affecting both zones A and B. This is less likely than a single zone fire and the consequences are less severe than the other scenarios considered. The frequency of the other three scenarios is the same based on the assumptions that the fire frequency is uniform per zone and that the operator error frequency is the same. Station blackout is the most severe condition and is quantified as follows:

$$FCRAC'(X) = FR(SD) * FR(X) * f_{CR,SD} * f_{CR7} * f'_{HE,2}$$

$$= 4.1E-8 \text{ (mean)}$$

$$FCRAC'(W) = FR(SD) * FR(W) * f_{CR,SD} * f_{CR7} * f'_{HE,2}$$

$$= 3.7E-8$$

where:

$FR(SD)$ = 0.37 (from Table 9-3)

$FR(X)$ = 0.51 (from Table 9-3)

$FR(W)$ = 0.45 (from Table 9-3)

$f_{CR,SD}$ = frequency of fires in the main control room during shutdown, from Section 8.2.1.4

= 6.3E-3/yr (mean)

f_{CR7} = fraction of control room fires affecting one particular zone, from SSPSA p. 9.4-34

= 8.1E-3 (mean)

$f'_{HE,2}$ = conditional frequency of operator error, failing to successfully establish shutdown cooling from the remote safe shutdown panel prior to core uncovery (2 hours) from Section 6.4

= 4.3E-3 (mean)

(4) RHR Equipment Vault #1 (RHR-1F-1B,2B,3B,4B,1D-Z)

This area includes RHR train A pump, heat exchanger, and valves as well as train A, SI, and CBS. This also includes cables for RHR suction valves for train A (RC-V23, RC-V22) and for train B (RC-V88). RC-V23 and V88 are powered from train A electrical bus, RC-V22 from train B. Due to the "cross-train depowering" scheme, RC-V22 and RC-V88 are opened and depowered (breakers removed) during shutdown. Thus, there is no potential for a hot short failing train B.

This area also contains RH-V35, V36 (RHR to SI/charging pump suctions) which are addressed in the "LOCA" fire analysis. Thus, a fire in this area will fail train A of RHR. The quantification is based on the SSPSA Section 9.4.4 except for $f_{AUX,SD}$.

$$FRHRA = FR(SD) * f_{AUX,SD} * f_{VLT} * f_{R,G} * f_{R,S} * Q_1 (T_G)$$

$$= 1.3E-4 \text{ (mean)}$$

where:

$FR(SD)$ = 0.37 (from Table 9-3)

$f_{AUX,SD}$ = frequency of fire in the PAB during shutdown, from Section 8.2.1.4

= 7.2E-2/yr (mean)

f_{VLT} = fraction of fires in the PAB that may occur in the RHR vault from SSPSA p. 9.4-10

= 1.13E-1 (mean)

$f_{R,G}$ = conditional frequency of fire occurring in the cable tray area given a fire in the vault. from SSPSA p. 9.4-12

= 2.5E-1 (mean)

$f_{R,S}$ = conditional frequency of pilot fire being large enough to propagate to other trays, from SSPSA p. 9.4-12

= 1.0

$Q_{1(TG)}$ = conditional frequency of a fire in the vault causing damage based on propagation and suppression rates, from SSPSA p. 9.4-11

= 1.75E-1 (mean)

The frequency of this scenario is much lower than FSGA (fire in switchgear room A) and the consequences are not as severe. Thus, this scenario is not included in the plant model.

(5) Containment (C-F-1,2,3-Z)

This area is considered for a fire causing multiple hot shorts in the controls for the RHR suction valves and resulting in a loss of all RHR. This is a very unlikely scenario because of the multiple hot shorts and because the frequency of fires in containment is very low. Also, the valves can be reopened at the valve switchgear. Thus, this scenario is not analyzed further.

(6) Containment Enclosure Fan Area/Mechanical Penetration Area (CE-F-1-Z, PP-F-1A,2A,3A, 1B,2B,3B,4B,5B-Z)

This area is considered for a fire causing loss of all RHR due to multiple hot shorts causing loss of RHR suction (RC-V23, V87) or loss RHR discharge (RH-V14, V26). Operator action is possible to manually, locally (in containment) open the suction valves. Also, the discharge valves are normally opened and depowered. Multiple hot shorts are considered to be very unlikely. Support systems are not affected. Thus, this area is not considered further.

(7) Electrical Tunnel - Train A (ET-F-1A, 1B-A)

These areas are considered for a fire causing a failure of the operating RHR pump due to loss of train A of service water pumps and valves. This scenario is analyzed in the SSPSA Section 9.4.8. The same quantification is used here except the frequency of the fire is adjusted for shutdown conditions:

$$\text{FETA} = \text{FR(SD)}\ 2 * f_{AUX,SD} * f_{TNL} * Q_1\ (T_G)$$

$$= 9.2\text{E-}5 \text{ (mean)}$$

where:

FR(SD) = 0.37 (from Table 9-3)

$f_{AUX,SD}$ = frequency of fire in the PAB during shutdown, from Section 8.2.1.4

= 7.[illegible]-2/yr (mean)

f_{TNL} = fraction of fires in the PAB that may occur in the electrical tunnels, from SSPSA p. 9.4-37

= 2.0E-2 (mean)

$Q_1(T_G)$ = condition frequency of the fire in the electrical tunnels causing damage, based on propagation and suppression rates, from SSPSA p. 9.4-38

= 1.75E-1 (mean)

The factor of 2 is used because of the two areas considered.

The frequency of this fire scenario is much lower than FSGA (fire in switchgear room A) and the consequences are not as severe. Thus, this scenario is not included in the plant model.

(8) Electrical Tunnels - Train B (ET-F-1C, 1D-A)

A fire in these areas could cause loss of service water train B, which is not assumed to be an initiating event at shutdown. However, in area ET-F-1C, cables for the powered RHR suction isolation valves is present. A single hot short may cause RC-V23 to close causing loss of the operating RHR train. This is recoverable at the switchgear or from inside the containment - manually opening the valve. This fire scenario is quantified as follows:

$FETB(X) = FR(SD) * FR(X) * f_{AUX,SD} * f_{TNL} * Q_1 (T_G) * f_{HS}$

$= 1.4E-5$ (mean)

$FETB(W) = FETB(X) * FR(W)/FR(X) = 1.3E-5$ (mean)

where:

$FR(SD) = 0.37$ (from Table 9-3)

$FR(X) = 0.51$ (from Table 9-3)

$FR(W) = 0.45$ (from Table 9-3)

$f_{AUX,SD} = 7.2E-2/yr$ (mean) - see (7) above

$f_{TNL} = 2.0E-2$ (mean) - see (7) above

$Q_1 (T_G) = 1.75E-1$ (mean - see (7) above

f_{HS} = fraction of tunnel fires causing a hot short for RC-V23 (estimate)

= 0.3

(9) PAB - Aux. Steam Condensate Tank Area (PAB-F-1J-Z)

This area contains cables for train A RHR suction valve (RC-V23). Hot short could cause loss of the operating RHR train. However, this failure is recoverable by locally opening the valve. Also, no additional equipment of importance is affected by this fire. Thus, it is not analyzed further.

(10) PAB - Electrical Tunnel Above RHR Vault (PAB-F-1G-A)

This area is considered for a loss of the operating RHR pump and loss of train A of PCC (pumps, valves) and train A of service water (pumps, valves). This area also contains cables for RHR train B suction valve (RC-V87) and RHR train B heat exchanger outlet valve (RH-HCV-607) and bypass valve (RH-FCV-619). Hot shorts may cause loss of the standby RHR train. The quantification is the same as the electrical tunnel - train B fire above (FETB):

$FETG(X) = FR(SD) * FR(X) * f_{AUX,SD} * f_{TNL} * Q_1 (T_G) * f_{HS}$

$= 1.4E-5$ (mean)

$FETG(W) = FETG(X) * FR(W)/FR(X) = 1.3E-5$ (mean)

where the variables are defined in (7) and (8) above.

(11) PAB - Chiller Pump Area (PAB-F-1A-Z)

This area contains cables for PCC train A (pumps, valves) and service water trains A and B (pumps, valves). All train B cables for service water are routed in conduit with a one hour, fire-rated barrier. This scenario is analyzed in SSPSA Section 9.4.10. The quantification is used from the SSPSA except for $f_{AUX,SD}$:

$$FPAB(X) = FR(SD) * FR(X) * f_{AUX,SD} * f_{P1A} * f_{P1A,S} * Q_2\ (T_G)$$

$$= 1.9E\text{-}5 \text{ (mean)}$$

$$FPAB(W) = FPAB(X) * FR(W)/FR(X) = 1.7E\text{-}5 \text{ (mean)}$$

where:

$FR(SD)$ = 0.37 (from Table 9-3)

$FR(X)$ = 0.51 (from Table 9-3)

$FR(W)$ = 0.45 (from Table 9-3)

$f_{AUX,SD}$ = 7.2E-2/yr (mean) - above

f_{P1A} = fraction of fires in PAB that may occur in this area, from SSPSA p. 9.4-41

= 2.0E-2

$f_{P1A,S}$ = severity factor, from SSPSA p. 9.4-42

= 1.3E-1

$Q_2\ (T_G)$ = conditional frequency of non-suppression, from SSPSA p. 9.4-42

= 5.4E-1

(12) PAB - Resin Fill Tank Area (PAB-F-2A-Z)

This area contains cables for service water train A (pumps, valves). This is expected to have a similar frequency as FP1A, above (see SSPSA p. 9.4-45) but affects only one train of support systems. Thus, this area is not analyzed further.

(13) PCC Pump Area (PAB-F-2C-Z)

This area contains PCC trains A and B (pump, valves, cables) and cables and valves for service water trains A and B. Train B cables are routed in conduit with one hour, fire-rated barrier. Based on the analysis in SSPSA Section 9.4.13, fire in the pump area failing all four pumps is not a credible scenario. A fire in the cable trains has the potential for causing loss of both trains of PCC (loss of service water requires hot shorts). This is quantified in SSPSA Section 9.4.13 as Scenario 2.

$$FPCC(X) = FR(SD) * FR(X) * f_{Aux,SD} * f_{P2C} * f_{P2C,G1} * f_{P2C,S2} * Q_3 (T_G)$$

$$= 1.2E-6 \text{ (mean)}$$

$$FPCC(W) = FPCC(X) * FR(W)/FR(X) = 1.0E-6 \text{ (mean)}$$

where:

$FR(SD)$ = 0.37 (from Table 9-3)

$FR(X)$ = 0.51 (from Table 9-3)

$FR(W)$ = 0.45 (from Table 9-3)

$f_{AUX,SD}$ = 7.2E-2 (mean) - above

f_{P2C} = fraction of PAB fires that may occur in this area, from SSPSA p. 9.4-47

= 1.6E-1 (mean)

$f_{P2C,G1}$ = geometric factor, from SSPSA p. 9.4-47

= 1.25E-1 (mean)

$f_{P2C,S2}$ = severity factor, from SSPSA p. 9.4-49

= 2.6E-2 (mean)

$Q_3(T_G)$ = conditional frequency of non-suppression from SSPSA p. 9.4-48

= 1.7E-1 (mean)

(14) <u>PAB - Water Cooler HX Area (PAB-F-3A-Z)</u>

This area contains cable and valves (SW-V15, V17) for service water trains A and B. In order to fail service water, the fire must cause multiple hot shorts to close valves without losing power to the valves. This is assessed to be very unlikely and the scenario is not analyzed further.

(15) East Main Steam/Feed Pipe Chase (MS-F-1A,2A,3A,4A,5A-Z)

This area contains cable for train A of service water (pumps, valves). The frequency of a fire in this area is judged to be similar to FETA (fire in electrical tunnel - train A) and is not significant in comparison to FSGA (fire in switchgear room A). Thus, this scenario is not included in the model.

(16) Service Water Pump House - Electrical Room A (SW-F-1B-A)

This area contains cable for SW train A pumps and valves. The frequency of a fire in this area is judged to be much lower than in the switchgear room because of the smaller floor area and the fact that this building has less foot traffic through it. Thus, this scenario is not analyzed further.

(17) Service Water Pump House (SW-F-1E-Z)

This area contains pumps and valves for SW trains A and B. Consistent with SSPSA Section 9.4.15, loss of all four pumps due to a fire is judged to be very unlikely because of large separation among pumps of redundant trains and lack of insitu intervening combustibles. Thus, this area is not considered further.

(18) Duct Banks (DCT-F-1A,1B,2A,2B,3B-0)

Each of these duct banks contain one train of cables for PCC or service water. A fire in duct banks is judged to be very unlikely because of the lack of insitu combustibles.

(19) Turbine Building

A fire in the turbine building is assumed to cause loss of offsite power (LOSP), consistent with SSPSA Section 9.4.14. Thus,

$$FTBLP'(X) = FR(SD) * FR(X) * f_{TB,SD} * f_{TB,GS}$$

$$= 3.2E\text{-}4/\text{year (mean)}$$

$$FTBLP'(W) = FTBLP'(X) * FR(W)/FR(X)$$

$$= 3.1E\text{-}4/\text{year (mean)}$$

where:

FR(SD) = 0.37 (from Table 9-3)

FR(X) = 0.51 (from Table 9-3)

FR(W) = 0.45 (from Table 9-3)

$f_{TB,SD}$ = frequency of turbine building fires, from Section 8.2.1.4

= 4.5E-2/yr (mean)

$f_{TB,GS}$ = conditional frequency of a fire causing LOSP given a turbine building fire, from SSPSA p. 9.4-51

= 3.9E-2 (mean)

8.2.1.4 Frequencies of Fires During Shutdown

The database for fire events was reviewed to determine the frequency of fires in critical buildings during shutdown. A summary of this data review and analysis is included in Appendix D. The frequencies of fires during shutdown in four locations (control room, cable spreading room, auxiliary building, and turbine building) were estimated as shown in Table 8-4. The events in the data base were categorized according to when fires could have occurred - shutdown only, shutdown or operation, or operation only. The frequency distributions of fires during shutdown only and fires during shutdown or operation were added to yield the total frequency of fires during shutdown. The results reported in Table 8-4 are in units of "per shutdown year". These distributions are multiplied by the shutdown fraction [FR(SD)] to yield frequencies in "per calendar year" to be consistent with the other initiators. These frequencies are then multiplied by the fraction of the shutdown in RCS Condition X (FR(X)) or in RCS Condition W (FR(W)) consistent with the initiator designation.

8.2.2 Internal Floods

The analysis of internal flood initiators is based on a review of SSPSA, Section 9.5 and a review of flooding events in the data base. The frequency of floods that could occur during shutdown was analyzed for various important locations in the plant subject to potentially large floods. This data analysis is summarized in Appendix E. This analysis shows that the frequency of floods during shutdown is not significantly greater than at operation.

Turbine Building events were the important internal floods in the SSPSA. During shutdown, floods in the RHR vault would be initiators, therefore, both of these areas were reviewed. The initiators of interest in these locations are as follows:

FLRHR - non-isolable flood in the RHR vaults due to a leak in the RHR piping. The RWST drains into one vault and spills over to the other vault through non-watertight doors. This results in failure of both trains of CBS, RHR and SI pumps. From SSPSA, Section 9.5.3.5, the upper bound (95th percentile) estimate of the frequency of such a pipe break is 3.0 E-5 per year. Assuming an error facto of 30 based on the pipe break distribution, the value is F(PB) = 8.5E-6. Thus:

FLRHR(X) = FR(SD) * FR(X) * F(PB) = 1.6E-6/year (mean)

FLRHR(W) = FR(SD) * FR(W) * F(PB) = 1.4E-6/year (mean)

where

FR(SD) = shutdown fraction
= 0.37 (from Table 9-3)

FR(X) = fraction of shutdown in RCS Condition X (drained)
= 0.51 (from Table 9-3)

FR(W) = fraction of shutdown in RCS Condition W (full)
0.45 (from Table 9-3)

FL1SG - flood in the turbine building with leakage into one switchgear room, causing loss of offsite power and failure of one emergency bus. The frequency of flood in the Turbine Building at shutdown is based on the data review summarized in Appendix E. The probability of leakage into the switchgear room A during shutdown is assumed to be the same as at power. The door is more likely to be open into the switchgear room out the presence of additional personnel compensates for this. Thus,

$$FL1SG(X) = [F'_L * f_{HE} * f_A + F'_{VL} * f_A] * FR(SD) * FR(X)$$

$$= 4.5\ E\text{-}6/yr \quad \text{(mean)}$$

$$FL1SG(W) = FL1SG(X) * FR(W)/FR(X)$$

$$= 3.9E\text{-}6/yr \quad \text{(mean)}$$

where,

F'_L = frequency of a large turbine hall flood given shutdown conditions (from Appendix E, Table 5-2).

= 9.7E-3/yr

F'_{VL} = frequency of a very large turbine hall flood (from Appendix E, Table 5-2).

= 2.7E-3/yr

f_{HE} = likelihood of operator failure to stop the leak (from SSPSA, p. 9.5-12).

= 2.9E-2

f_A = likelihood of leakage into switchgear room A (from sSPSA, p. 9.5-13).

= 8.0E-3

FR(SD) = shutdown fraction

= 0.37 (from Table 9-3)

FR(X) = 0.51 (from Table 9-3)

FR(W) = 0.45 (from Table 9-3)

The following floods were initiators in the SSPSA but are not included in this shutdown analysis:

FLLP - flood in the turbine hall causing loss of offsite power. This loss of offsite power is potentially recoverable within a few hours. Loss of offsite power due to fire (FTBLP) is included at a higher frequency and is a much less recoverable event. This initiator is not considered further.

FL2SG - flood in the turbine hall leaking into both switchgear rooms, causing a station blackout. This event is excluded because its frequency (.37 * 8.6 E-8/yr) is less than the flood FL1SG and hardware unavailability of the other diesel during shutdown (DG1A in in Section 7.2.2).

8.2.3 Heavy Loads

Due to the maintenance activities which occur during shutdown, the potential for heavy loads falling on critical shutdown components is considered. An analysis of heavy loads at Seabrook has been performed in Reference 10 and was reviewed for this analysis. Based on the referenced report, no credible accident scenario could be identified.

In order to be an initiating event during shutdown, the load falling would have to cause a LOCA or a loss of cooling accident. No credible scenario could be identified where a load drop would cause a LOCA or would fail both trains of RHR or PCC or service water. This is due to the design and testing of the cranes and cables which make failure unlikely and the procedural and mechanical limitations that make serious operator error unlikely.

TABLE 8-1

EXTERNAL AND INTERNAL HAZARD INITIATING EVENTS

Initiating Event	Description	Frequency Distribution (per year) Frequency Mean	5th Percentile	50th Percentile	95th Percentile
SSBO(X) SSBO(W)	Seismic Station Blackout	1.1E-6 2.3E-6	1.4E-8 2.6E-8	3.0E-7 6.4E-7	5.2E-6 9.9E-6
SL'(W)	Seismic Large LOCA	3.8E-7	1.3E-10	3.6E-8	2.3E-6
FLSW(X) FLSW(W)	External Flood of Service Water	3.0E-7 2.7E-7	3.0E-8 2.0E-8	1.6E-7 1.2E-7	8.7E-7 7.9E-7
TCTL(X) TCTL(W)	Truck Crash into SF_6 Transmission Lines	5.1E-5 4.6E-5	1.9E-6 1.4E-6	2.1E-5 1.5E-5	2.2E-4 1.8E-4
FSGA(X) FSGA(W)	Fire in Switchgear Room A	2.5E-3 2.3E-3	1.7E-4 1.2E-4	1.2E-3 8.8E-4	7.9E-3 6.9E-3
FCRAC(X) FCRAC(W)	Fire in Control Room - Loss of AC Power	4.1E-8 3.7E-8	1.1E-11 7.9E-12	1.1E-9 8.4E-10	9.0E-8 7.2E-8
FETB(X) FETB(W)	Fire in Electrical Tunnel for Train B	1.4E-5 1.3E-5	4.6E-8 3.2E-8	1.4E-6 1.1E-6	5.0E-5 4.7E-5
FPCC(X) FPCC(W)	Fire in PAB - Failure of PCC	1.2E-6 1.0E-6	4.7E-10 3.5E-10	4.5E-8 3.5E-8	4.7E-6 3.5E-6
FETG(X) FETG(W)	Fire in Electrical Tunnel Above RHR Vault	1.4E-5 1.3E-5	4.6E-8 3.2E-8	1.4E-6 1.1E-6	5.0E-5 4.7E-5
FTBLP(X) FTBLP(W)	Fire in Turbine Building - Loss of Offsite Power	3.2E-4 3.1E-4	5.2E-6 3.8E-6	9.6E-5 7.4E-5	1.6E-3 1.3E-3
FPAB(X) FPAB(W)	Fire in PAB - Chiller Pump Area	1.9E-5 1.7E-5	4.4E-8 3.1E-8	1.6E-6 1.2E-6	5.6E-5 4.0E-5

TABLE 8-1

EXTERNAL AND INTERNAL HAZARD INITIATING EVENTS

Initiating Event	Description	Frequency Distribution (per year)			
		Frequency Mean	5th Percentile	50th Percentile	95th Percentile
FLRHR(X) FLRHR(W)	Internal Flood of RHR Vaults	1.6E-6 1.4E-6	4.9E-9 3.4E-9	1.6E-7 1.1E-7	5.0E-6 4.6E-6
FLISG(X) FLISG(W)	Flood in Turbine Building and Switchgear Room A	4.5E-6 3.9E-6	3.0E-8 2.2E-8	6.5E-7 4.9E-7	1.4E-5 1.1E-5

TABLE 8-2

IMPACT OF EXTERNAL AND INTERNAL HAZARD INITIATORS

INITIATOR	DESCRIPTION	IMPACT - DIRECT SYSTEM FAILURES: OFFSITE POWER	EMER AC	PCC	SW	RHR
SSBO	Seismic Station Blackout - loss of offsite power with seismic or non-seismic failure of both diesel generators, no recovery assumed.	X	X	-	-	-
SLL	Seismic Large LOCA.	X	-	-	-	-
FLSW	External Flood of Service Water and Cooling Tower Switchgear Rooms, loss of offsite power assumed in accompanying storm. No recovery assumed. storm. No recovery assumed.	X	-	-	X	-
TCTL	Truck Crash into SF_6 Transmission Lines - loss of offsite power, no recovery assumed.	X	-	-	-	-
FSGA	Fire Switchgear Room A.	-	1/2	-	-	-
FCRAC	Fire in Control Room - loss of all controls for Emergency AC Power.	X(a)	X(a)	-	-	-
FETB	Fire in Electrical Tunnel Train B.	-	-	-	1/2(b)(c)	1/2(d)
FPCC	Fire in PAB - failure of PCC.	-	-	X	-	-
FETG	Fire in Electrical Tunnel Above RHR Vault.	-	-	1/2	1/2	X
FTBLP	Fire in Turbine Building - Loss of Offsite Power, no recovery assumed.	X	-	-	-	-

TABLE 8-2

IMPACT OF EXTERNAL AND INTERNAL HAZARD INITIATORS

		IMPACT - DIRECT SYSTEM FAILURES				
INITIATOR	DESCRIPTION	OFFSITE POWER	EMER AC	PCC	SW	RHR
FPAB	Fire in PAB - Chiller Pump Area.	-	-	1/2	X	-
FLRHR	Internal flood in the RHR vault, no recovery assumed.	-	-	-		X
FLISG	Flood in the Turbine Hall and Switchgear Room A, no recovery assumed.	X	1/2	-	-	-

Notes:

X Denotes two train failures due to the fire (direct failures only), except for Offsite Power which is not divided by train. Losses of offsite power in this table are assumed to be non-recoverable in the short term, i.e., the diesels must run for 24 hours.

1/2 Denotes single train failure due to the fire (direct failures only). While the fire effects a definite train, either A or B, it is conservatively assumed that the fire affects the operating train, which for this study is modeled as the "A" Train.

(a) Failures of controls and indications in Control Room. Systems assumed recoverable when controlled from RSSP. Initiating frequency includes failure to recover.

(b) Cooling Towers available. No credit taken because of complications due to fire.

(c) Loss of SW Train B.

(d) Operating RHR Loses Suction (valves closes).

TABLE 8-3

SHUTDOWN FIRE ANALYSIS - CRITICAL COMPONENTS RESULTING IN LOSS OF RHR

SYSTEM	DESCRIPTION	FAILURE	FIRE ZONE
RHR(1)	RH-P-8A (RHR train A pump)	Loss of Power	(a),(b),(c) (RHR-F-1B-Z to 4B-Z,1D-Z)
	RC-V23 (train A suction valve powered by train A	Hot Short - Close	Containment (C-F-1-Z,2-Z) Switchgear Room B (CB-F-1A-A,3A-A) El. Tunnel (ET-F-1A-A,1B-A,1C-A) PAB (PAB-F-1J-Z,1G-A) (RHR-F-1B-Z to 4B-Z,1D-Z)
	RH-HCV-606 (HX discharge valve)	Hot Short - Close	(a),(b),(c), (RHR-F-1B-Z to 4B- ,1D-Z)
	RH-FCV-618 (HX bypass valve)	Hot Short - Open	
PCC(2)	CC-V145 (RHR HX cooling water outlet)	Hot Short - Close	(a),(b),(c),PAB (PAB-F-1G-A) RHR Vault (RHR-F-1B-Z to 4B-Z,1D-Z)
	CC-P-11A (PCC train A pump)	Loss of Power	(a),(b),(c) PAB (PAB-F-2C- 1G-A)
	CC-P-11C (PCC train A standby pump)	Loss of Power	
	CC-TV-2171-1 (PCC HX discharge valve)	Hot Short - Close	(a),(b),(c) PAB (PAB-F-2C-Z,1G-A)
	CC-TV-2171-2 (PCC HX bypass valve)	Hot Short - Open	
SW(3)	SW-P-41A (SW train A pump)	Loss of Power	(a),(b),(c), Cooling Tower (CT-F-1D-A) Cooling Tower (CT-F-2B-A) El. Tunnel (ET-F-1A-A,1B-A) Pipe Chase (MS-F-1A-Z to 5A-Z) PAB (PAB-F-1A-Z,2A-Z,2C-Z,1G-A) SW Pumphouse (SW-F-1B-A,1E-Z)
	SW-P-41C (SW train A standby pump)	Loss of Power	
	SW-V2 (pump discharge MOV)	Hot Short - Close	(a),(b),(c), El. Tun. (ET-F-1A-A,1B-A) Pipe Chase (MS-F-1A-Z to 5A-Z) SW Pumphouse (SW-F-1B-A,1E-Z)
	SW-V22 (pump discharge MOV)	Hot Short - Close	

TABLE 8-3

SHUTDOWN FIRE ANALYSIS - CRITICAL COMPONENTS RESULTING IN LOSS OF RHR

SYSTEM	DESCRIPTION	FAILURE	FIRE ZONE
SW(3)	SW-V15 (CC HX discharge MOV)	Hot Short - Close	(a),(b),(c) PAB (PAB-F-2C-Z,3A-Z,1G-A)
	SW-20 (MOV in discharge path to transition structure)	Hot Short - Close	(a),(b),(c) PAB (PAB-F-2C-Z,1G-A)
	SW-V63 (MOV to discharge tunnel)	Hot Short - Close	Valves locked open
	SW-V64 (MOV to intake tunnel)	Hot Short - Open	
	SW-V44 (MOV from intake tunnel)	Hot Short - Close	

Fire Areas:

(a) Switchgear Room A (CB-F-1A-A)

(b) Cable Spreading Room (CB-F-2A-A)

(c) Control Room (CB-F-3A-A)

(1) RHR - only loss of train A is considered to be initiating event, consistent with model that train A is the operating train. RC-V22 (train A suction valve powered by train B) is depowered and thus cannot fail closed. RV-V14 (RHR pump discharge) is opened and depowered and thus cannot fail closed. RH-FCV-610 (RHR pump miniflow) line failing closed may degrade flow but does not fail the train.

(2) PCC - only loss of train A is considered to be initiating event, as above. Opening/closing of PCC valves to other heat loads is assumed not to be a failure of the system.

(3) SW - only loss of train A is considered to be initiating event, as above. SW-V34 (discharge to cooling tower) is assumed not to be a failure of the system since cool water from tunnels is still available.

TABLE 8-4

SHUTDOWN FIRE FREQUENCIES BY LOCATION

LOCATION	FIRE FREQUENCY (per shutdown year)			
	Mean	5th Percentile	50th Percentile	95th Percentile
Control Room	6.3E-3	2.1E-4	2.5E-3	2.4E-2
Cable Spreading Room	5.6E-3	1.7E-4	2.0E-3	1.4E-2
Auxiliary Building	7.2E-2	6.1E-3	5.0E-2	2.0E-1
Turbine Building	4.5E-2	9.9E-4	1.9E-2	1.5E-1

9.0 DATA ANALYSIS

This section contains the component failure and maintenance data used in the systems analysis (Section 9.1) and the shutdown events data base which includes the frequency and duration in a particular shutdown plant evolution (Section 9.2). Section 9.3 summarizes the analysis of the data base of actual losses or degradations of RHR.

9.1 Component Failure Data

The component failure and repair data used for the shutdown analysis was taken from Section 6 "Data Analysis" of the SSPSA (Reference 1). Since Seabrook does not have significant operating data, this industry operating data which has been reviewed for applicability to Seabrook, was judged to continue to be the most appropriate to use. The component failure rate data from the SSPSA used in this study is summarized in Table 9-1 along with the specific components which apply to ea data distribution. These distributions are based on plant specific data from 8 plants that was collected, classified and analyzed by PLG in PRAs. The distributions listed account for sparcity of data and plant-to-plant variability in these rates. Each component failure mode has an assigned "Z variable" (e.g., ZIPMOS = normally operating motor driven pump fails to start on demand) which is keyed to a distribution provided by the SSPSA data analysis. For this study, these distributions were approximated by assumed lognormal distributions that have the same mean values and range factors. Table 9-2 contains the common cause failure parameters (beta factors) from the SSPSA that were used in this study. The beta factors are applied where common cause failures are judged important (see Section 7).

9.2 Shutdown Events Data Base

The shutdown data variables summarized in Table 9-3 have been quantified primarily using data from the Zion Nuclear Plants. Data from Zion was used because it is judged to be representative for PWRs with regard to plant availability and, importantly, detailed shutdown data is available from these units in NSAC-84 (Reference 6). This data was used to create uncertainty distributions for each data variable that accounts for the plant-to-plant variability between Zion and Seabrook.

The data variables in Table 9-3 can be divided into two groups: (1) those used to quantify the procedural trees and the procedural initiators coming out of them; and (2) those used to quantify the other initiators - internal/external hazard initiators and support system failure initiators.

The procedural initiators are quantified in Section 5.4 based on the duration in each plant evolution (e.g., tree C1 = refueling outage, cooldown evolution) and the frequency of each type of shutdown (e.g., Case C = refueling outage). Table 9-4 and Figure 9-1 illustrate the mission times in each Procedural event tree. These data variables allow quantification of failures over time (e.g., RHR pump fails to continue to run during plant evolution C1) which depends on the duration of outage. These variables also allow quantification of demand failures (e.g., RHR pump fails to start on demand in plant evolution C1) which depends on the frequency of outages. The duration variables (T(AO) through T(C6)) in Table 9-3 were assigned data variables using a three bin histogram. The minimum and maximum values from the Zion data were weighted 10% each; the average value was weighted 80%. As noted in the table, variables T(AO), T(BO), and T(CO) are the times from the point of reactor trip to RHR initiation and are used only in the quantification of time for operator action (see Section 5.6). Also, variables T(A1), T(B2), and T(C4) include, in addition to time for the plant evolution, time in stable shutdown condition while maintenance is performed. Finally, in the trees B2 and C4, the RCS is in the drained condition (X); in tree B3, the RCS is in refueling mode (Y); for all other trees, the RCS is full (W).

The remainder of the data in Table 9-3 is used to quantify the frequency of the internal/external hazards initiators (see Section 8) and the support system failure initiators (see Section 7). These initiators are dependent on the average duration of the outage (the exposure period) and the condition of the RCS - drained (X) or full (W). The duration in each RCS condition (in units of hours per year) is calculated by multiplying the frequency of outages in which the RCS condition can occur times the duration in the RCS condition per outage. Thus:

$$T(W) = F(A) * [T(A1) + T(A6)] + F(B) * [T(B1) + T(B5) + T(B6)] + F(C) * [T(C1) + T(C2) + T(C5) + T(C6)]$$

$$T(X) = F(B) * T(B2) + F(C) * T(C4)$$

$$T(Y) = F(C) * T(C3)$$

The total annual duration of shutdown is:

$$T(SD) = T(W) + T(X) + T(Y)$$

The fraction of the shutdown in each RCS condition is given by:

$$FR(X) = T(X)/T(SD)$$

$$FR(W) = T(W)/T(SD)$$

The fraction of year in shutdown is:

$$FR(SD) = \frac{T(SD)}{T(SD) + T(\overline{SD})}$$

where

$T(\overline{SD})$ = annual duration not shutdown

= 0.63 * 8760 hours per year

= 5520 hours

9.3 <u>Data Analysis of RHR Event Data Base (Appendix A)</u>

Appendix A contains a listing of actual losses or degradations of RHR based on a review of data from 1982 through 1986. In this section, the data is analyzed to determine the applicability of this data to Seabrook and the historical frequency of each failure mode. The frequency is based on 5 calendar years each for 46 PWRs and somewhat less time for 17 PWRs which came on line during the five year period - a total of 261 years for 63 PWRs. The data from Appendix A was not used directly to quantify the model but was used to develop the model structure.

1. <u>Suction Valve Closure (Table A-1 in Appendix A)</u>

   There were 38 suction valve closure events in 22 different plants for an annual frequency of 0.146 events per plant year (38/261). While specific events may or may not be applicable to Seabrook, this failure mode is assumed to be a generic concern applicable to Seabrook based on the large number of affected plants. This failure mode is included in the model in the procedure event trees, specifically top event SA in trees 1, 3, 5, and 6. Based on the model, the calculated frequency is 0.04 events per year. This is significantly less than the data due to the Seabrook design which has two inadvertent suction lines and the suction valve cross train depowering alignment. These events break down into the following causes:

- o maintenance/test error - 30 (79%)
- o instrument, inverter failure - 7 (18%)
- o non listed - 1 (3%)

Thus, suction valve closure frequency is dominated by maintenance/test error. This should be less likely at Seabrook because of the arrangement of the suction valves - two suction lines with two valves (one A train powered, other B train powered) per line and with the opposite powered valve open and depowered (i.e., the B train powered valve depowered in the A train suction line).

The subsequent operator response to the suction valve closure events from the data is as follows:

- o RHR restored in < 15 min. - 29 (76%)
- o RHR restored in 15 to 30 min. - 5 (13%)
- o RHR restored in > 30 min. - 4 (11%)

The four events that went more than 30 minutes without RHR cooling are as follows:

(1) McGuire - RCS heatup > 200°F

(2) D. Canyon 1 - RHR pump ran for 1 hr., pump damage

(3) Farley 1 - RHR pump tripped in 5 minutes, RHR restored in 52 minutes

(4) Ginna - RHR pump ran for 2 hours with suction valves closed

This data lends support to the assumption of at least 20 to 30 minutes for operator action given loss of pump suction before the pump damage. Assuming two events (D. Canyon 1 and Ginna) of the 38 suction valve closure events went to the point of pump damage, the conditional frequency of the operator failing to trip the pump is:

data - 0.05 (2/38)

model - 0.0005 (split fraction TP1, Table 5-7)

The model is two orders of magnitude smaller in frequency. This difference cannot be justified without the presence of low flow prevortexing alarms, operator response procedures, and training assumed at Seabrook.

2. <u>Pump Cavitation Due to Low RCS Level (Table A-2)</u>

there were 25 events of low level pump cavitation in 14 different plants, for an annual frequency of 0.096 events per plant year. This failure mode is also assumed to be a generic concern applicable to Seabrook based on the number of affected plants. This is modeled in the procedure event trees 2 and 4. Based on the model, the calculated annual frequency of these events is 0.05 events per plant year. This lower frequency is a result of improvements to the level monitoring system that were assumed to be installed. These events break down into the following causes:

- o erroneous RCS level indication - 13 (52%)
- o operator fails to maintain level - 10 (40%)

o air/gas entrainment - 2 (8%)

The subsequent operator response to low level pump cavitation from the data base is as follows:

o RHR restored - time not given - 1 (44%)

o RHR restored in < 60 min. - 9 (36%)

o RHR restored in > 60 min. - 5 (20%)

The five events that went more than 60 minutes without RHR cooling are as follows:

(1) N. Anna 2 - 60 min. - erroneous RCS level indication

(2) McGuire 2 - 62 min. - operator fails to maintain level

(3) N. Anna 2 - 2 hrs. - erroneous RCS level indication

(4) Zion 2 - 75 min. - operator fails to maintain level

(5) San Onofre 2 - 90 min. - air/gas entrainment

3. Loss of Reactor Coolant Inventory via the RHRS - Shutdown LOCA (Table A-3)

Five separate events at four different plants were reported with loss of reactor coolant inventory, as follows:

(1) Maine Yankee - LOCA to RWST

(2) Ginna - LOCA to containment sump - sump isolation valves inadvertently opened. (This failure is unlikely at Seabrook due to check valves in sump suction line).

(3) Calloway - LOCA to RWST - RCS depressurized to RWST.

(4) Farley - Overpressurization, RHR relief valve opened. (2 events)

Based on the four events that are potentially applicable to Seabrook, the historical frequency of shutdown LOCAs is 0.015 events per plant year. (4/261)

These events were modeled to some degree in the explicit LOCAs that are included in this study, including L1 (relief valve LOCA due to overpressurization), L3 (LOCA back to the RWST after refueling) and LS (LOCA to the sump, which includes check valve severe leakage). The total frequency of LOCAs assumed in this study (see Table 3-2) is about 2.6E-3 per year, a factor of five less than the data.

4. Loss of RHR or LOCA Due to Automatic Initiation of Low Pressure Safety Injection/Recirculation (Table A-4).

No actual failures due to this cause were identified.

5. Loss of RHR Due to Other Valve Closure or Excessive Pump/Cooler Bypass Flow (Table A-5).

No failures were identified.

6. Loss of RHR - Hardware Failure (Table A-6).

There were 23 hardware losses of RHR during shutdown in 14 plants, for an annual frequency of 0.088 events per year. This compares favorably to the frequency of hardware failures of RHR from the model of 0.128 events per year. This total comes from summing the frequency of procedure-initiated transients W5A through W6N, X5N, X6N, and Y5N as shown in Table 3-2.

The events break down into the following causes:

- pump breaker tripped - I&C failure - 7 (30%)

- o pump tripped - operator/maint. error - 7 (30%)
- o pump seal failure - 4 (17%)
- o oil leak - 2 (9%)
- o pump f ils to start - 2 (9%)
- o pump shaft failure - 1 (4%)

Many of these failures could be quickly recovered (e.g., pump tripped or pump fails to start), or the pump could continue to run (e.g., pump seal failures). However, the plant response model assumed that RHR hardware failures were not recoverable within 24 hours.

The events are included in the model in top events RI and RM in the procedure trees and in top event RR in the plant response tree.

7. Loss of RHR - Planned Maintenance (Table A-7).

There was one event in this category, involving the train A RHR pump which was declared inoperable due to excessive seal leakage while the train B diesel was inoperable due to maintenance and could not be quickly restored. The decision was made to leave the train A RHR pump aligned until the diesel was restored since the pump could still operate. This event provides anecdotal evidence of potential plant configurations during shutdown which are permitted by Technical Specifications (i.e., the disabling of one train of support systems). This has been covered in the model by including unavailability due to planned maintenance in the systems analysis.

8. <u>Inability to Establish RHR Flow - RHR Valves Fail to Open (Table A-8).</u>

There were six events involving RHR suction or discharge MOVs which failed to open on demand. Four of the six events were due to improper settling of motor torque switches. This failure mode is contained in top event RI (operator initiates RHR cooling) in procedural tree 1. This top event includes failure to open of MOVs in the discharge path and heat exchanger cooling. The result of failure of this top event is conservatively assumed to result in hardware loss of RHR and require continued steam generator cooling.

9. <u>RCS Void Formation During RHRS Operation (Table A-9).</u>

(No events identified).

10. <u>Miscellaneous Loss of RHR Events (Table A-10).</u>

Nine miscellaneous events involving the RHR system are listed in this category. Two events involve tube leaks in RHR heat exchangers. The events were minor so that heat transfer and primary inventory were not affected. Plugging or gross leakage of the heat exchangers is included in the model and is assumed to cause loss of RHR.

Two events involved loss of suction - one due to nitrogen intrusion, the other unknown. There are a number of other sources of loss of suction resulting in a relatively high frequency for this event (see items 1 and 2 above). These additional events are not significant contributors to this frequency.

One event involved loss of RHR during refueling due to a rope that was dropped into the refueling pool. While this specific cause of RHR failure is not included in the model, loss of RHR during refueling is not significant due to the large primary inventory.

Two events were small leaks - one in RHR piping and the other a pump seal leak. Both events were apparently small enough to not be classified as LOCAs. The pump seal LOCA was included in the model (LOCA LP) as a seal failure resulting from overpressurization.

Two pump failures were included - one failure to start and one failure to run (vibration) during a test. These events are included in the model through the top events RI and RM in the procedure trees and RR in the plant response trees.

9.4 Data Comparison with NSAC-52

NSAC-52 "Residual Heat Removal Experience Review and Safety Analysis" (Reference 7) was reviewed briefly to compare the frequency of the dominate RHR failure modes from the five year period (January 1976 to December 1981) in NSAC-52 with the five year period (January 1982 to December 1986) in Appendix A. NSAC-52 covers a total of 194 years for 47 PWRs. The failure rates compare as follows:

- Suction Valve Closure

  Appendix A data - 0.146 events per plant year (38 events/261 yr)
  NSAC-52 data - 0.139 events per plant year (37 events/194 yr)

- Pump Cavitation Due to Low RCS Level

  Appendix A data - 0.096 events per plant year (25 events/261 yr)
  NSAC-52 data - 0.062 events per plant year (12 events/194 yr)

o Loss of RHR - Hardware Failure

Appendix A data - 0.088 events per plant year (23 events/261 yr)
NSAC-52 data - 0.072 events per plant year (14 events/194 yr)

From the results above, it is apparent that the failure rates for suction valve closure and RHR hardware failure are relatively constant for the two five-year periods. The rate of pump cavitation has increased in the more recent period. This may be due to increased steam generator inspections and maintenance which requires longer times in drained down condition.

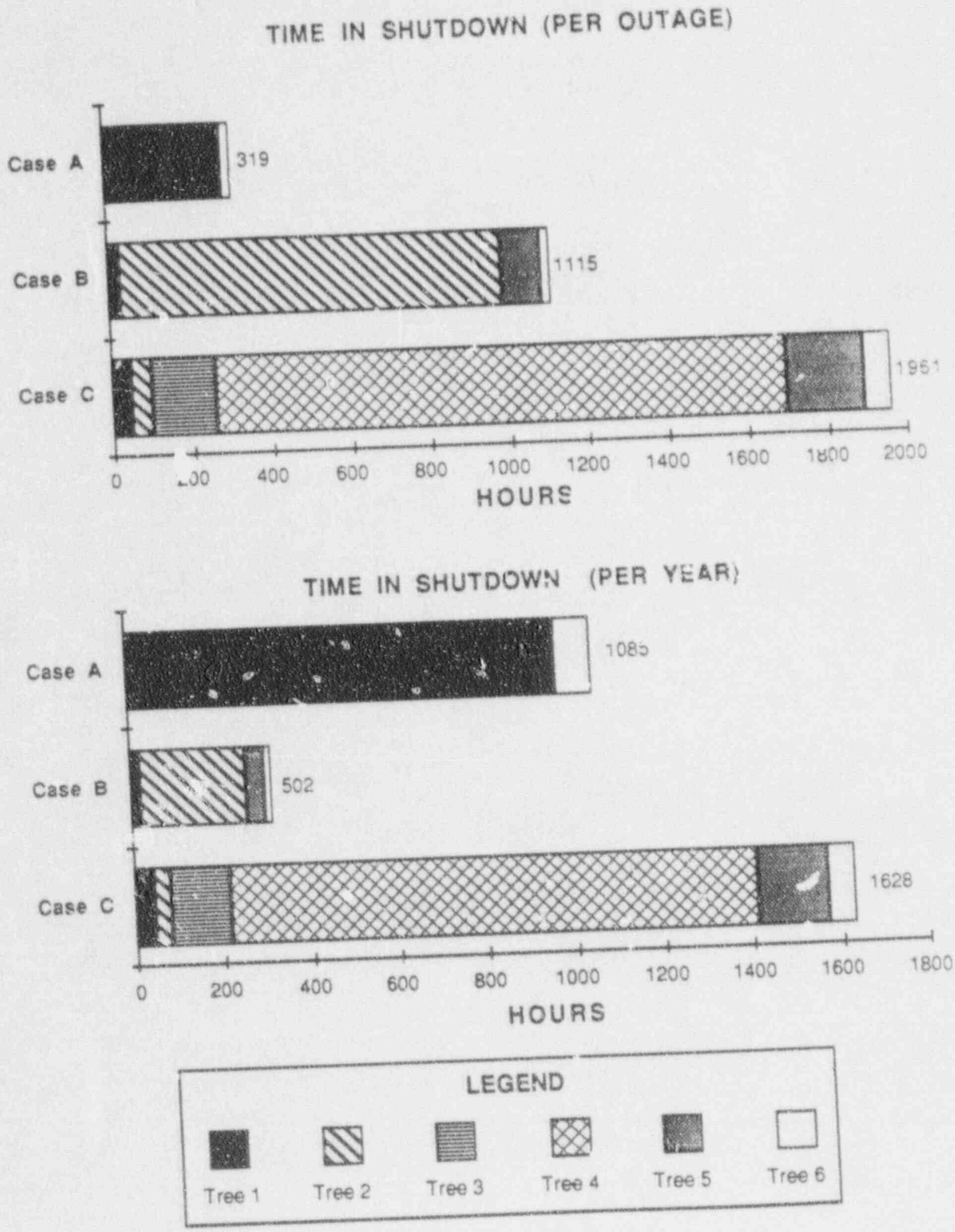


FIGURE 9 - 1 Average Residence Time in Procedure Trees

TABLE 9-1

COMPONENT FAILURE RATE DATA

Component Description	Failure Mode	Mean	Error * Factor
Normally Operating Motor Driven Pumps: RHR, Charging, SW, PCC pumps	ZIPMOS: Fail to Start on Demand	2.35E-3	5.1
	ZIPMOR: Failure During Operation	3.36E-5/hr	5.7
Standby Motor Driven Pumps: SI, EFW	ZIPMSS: Fail to Start on Demand	3.29E-3	6.7
	ZIPMSR: Failure During Operation	3.42E-5/hr	5.4
Turbine Driven Pump: EFW	ZIPTSS: Fail to Start on Demand	3.31E-2	3.5
	ZIPTSP: Failure During Operation	1.03E-3/hr	6.9
Motor Operated Valve: All Systems	ZIVMOD: Fail to Open/Close On Demand	4.30E-3	3.9
	ZIVMOT: Transfer Open/Closed During Operation	9.27E-8/hr	4.8
	ZIVMOE: Fail to Close on Demand While Showing Closed	1.07E-4	4.0
Air Operated Valves: All Systems	ZIVAOD: Failure to Operate on Demand	1.52E-3	3.3
	ZIVAOF: Failure to Transfer to Failed Position on Demand	2.66E-4	10.0
	ZIVAOT: Transfer Open/Closed During Operation	2.67E-7/hr	6.1
Check Valves: All Systems	ZIVCOL: Gross Leakage During Operation	5.36E-7/hr	4.1
	ZIVCOP: Transfer Closed, Plugged	1.04E-8/hr	3.0
Manual Valves: All Systems	ZIVHOT: Transfer Open/Closed During Operation	4.20E-8/hr	8.8
Relief Valve: RHR	ZIVRIS: Failure to Reseat on Demand	2.87E-3	9.6
	ZIVR2O: Failure to Open on Demand	2.42E-5	9.6
PORV: Primary System	ZIVR3O: Failure to Open on Demand	4.27E-3	3.0
	ZIVR3C: Failure to Reseat on Demand	2.50E-2	3.0
Heat Exchanger: RHR, PCC	ZIHXRB: Rupture/Excessive Leakage During Operation	1.95E-6/hr	4.1

TABLE 9-1

COMPONENT FAILURE RATE DATA

Component Description	Failure Mode	Mean	Error * Factor
Diesel Generator	ZIDGSS: Failure to Start on Demand	2.14E-2	4.3
	ZIDGS1: Failure During First Hour of Operation	1.69E-2/hr	6.1
	ZIDGS2: Failure to Run After First Hour	2.50E-3/hr	4.9
Flow Transmitter	ZITRFR: Failure During Operation	6.25E-6/hr	4.8
Level Transmitter	ZITRLR: Failure During Operation	1.57E-5/hr	3.1
Pressure Transmitter	ZITRPR: Failure During Operation	7.60E-6/hr	4.7
Relay	ZIRLIR: Failure During Operation	4.20E-7/hr	7.1
Bistable	ZISWBI: Spurious Operation	2.21E-6/hr	42
Signal Modifier	ZISMDR: Failure During Operation	2.94E-6/hr	3.7

* Error factor = $\sqrt{(95\text{th Percentile}/5\text{th Percentile})}$

TABLE 9-2

COMPONENT BETA FACTOR DATA

Component	Failure Mode	Mean	Error Factor
Charging Pump	ZBPHPS: Fail to Start	5.88 E-2	3.9
	ZBPHPR: Fail to Run	6.40 E-2	4.9
SW Pump	ZBPSWS: Fail to Start	1.11 E-1	2.1
	ZBPSWR: Fail to Run	7.62 E-2	2.0
PCCW Pump	ZBPCWS: Fail to Start	3.65 E-2	10.0
	ZBPCWR: Fail to Run	2.32 E-2	8.7
RHR Pump	ZBPDHS: Fail to Start	6.68 E-2	3.9
	ZBPDHR: Fail to Run	2.76 E-1	2.1
MOV	ZBVMOD: Fail to Open/Close on Demand	4.23 E-2	1.8
Diesel Generator	ZBDGSS: Fail to Start	1.46 E-2	3.5
	ZBDGSR: Fail to Run	3.25 E-2	2.1
Generic Component	ZBGN1A:	1.25 E-1	22

TABLE 9-3

SHUTDOWN DATA VARIABLES

Data Variable	Description	Data Distribution Mean	5th Percentile	50th Percentile	95th Percentile	Reference
	(a) Time (hours per outage) in Procedure Tree					
T(A0)	o A0	22	18	20	37	Ref. 6, Fig. 3-4
T(A1)	o A1	295	41	222	1120	Ref. 6, Table 3-4 (b)
T(A6)	o A6	24	12	24	36	Estimated
T(B0)	o B0	19	9	18	37	Ref. 6, Fig. 3-5
T(B1)	o B1	31	6	27	83	Ref. 6, Fig. 3-4
T(B2)	o B2	959	537	922	1670	Ref. 6, Table 3-4 (c)
T(B5)	o B5	101	30	90	252	Ref. 6, Table 3-4
T(B6)	o B6	24	12	24	36	Estimated
T(C0)	o C0	55	36	54	85	Ref. 6, Fig. 3-1
T(C1)	o C1	50	23	46	107	Ref. 6, Fig. 3-1
T(C2)	o C2	47	9	49	73	Ref. 6, Fig. 3-1
T(C3)	o C3	161	74	160	253	Ref. 6, Table 3-1
T(C4)	o C4	1440	740	1430	2240	Ref. 6, Table 3-1 (d)
T(C5)	o C5	193	24	184	430	Ref. 6, Table 3-1
T(C6)	o C6	72	48	72	96	Estimated
	Frequency (outages per year) of					
F(A)	o Case A - Non-Drained Maint.	3.4	1.0	2.2	7.3	(e)
F(B)	o Case B - Drained Maint.	0.45	0.125	0.25	2.4	(f)
F(C)	o Case C - Refuel.	0.83	0.67	0.83	1.0	(g)
	Time (hours per year) in RCS Condition					
T(W)	o W - RCS Filled	1455	498	1020	3510	(h)
T(X)	o X - RCS Drained	1627	815	1390	3180	(h)
T(Y)	o Y - Refueling	134	57	115	191	(h)
	Time in Shutdown (hours per year)					
T(SD)		3214	1930	2600	5410	(h)
	Fraction of Shutdown in RCS Condition					
FR(X)	o X	0.51	0.28	0.55	0.73	(h)
FR(W)	o W	0.45	0.22	0.40	0.70	(h)
	Fraction of Year in Shutdown					
FR(SD)		0.37	0.24	0.30	0.47	(h)

TABLE 9-3

SHUTDOWN DATA VARIABLES

(a) The Procedure Tree data variables are the durations of plant evolutions (Trees 1-6) during specific shutdown cases (A, B, C).

The data variables T(AO), T(BO), and T(CO) are the durations fr the time the reactor is tripped until RHR cooling is in..ated. This duration, while the plant is in Mode 3, is not part of the study because the plant configuration is more like at-power than shutdown conditions. However, these times are used in computing the time to core uncovery with no decay heat removal, which is a function of the tire after shutdown.

The rest of the Procedure tree data variables are illustrated in Table 9-4.

(b) T(A1) = T(A) - T(AO) - T(A6)

where T(A) = Total time in Case A shutdown (non-drained maintenance) - from Ref. 6, Table 3-4

$T(A1)_{05} = T(A)_{MIN} - T(AO)_{05} - T(A6)_{05}$

$T(A1)_{50} = T(A)_{AVG} - T(AO)_{50} - T(A6)_{50}$

$T(A1)_{95} = T(A)_{MAX} - T(AO)_{95} - T(A6)_{95}$

Note that in Table 3-4 of Reference 6, all but four maintenance outages are assumed to be non-drained, based on information in Column 8. Three outages are labeled "draindown" (32 hr, 24 hr, and 32 hr). The fourth outage is labeled "information missing" but the "minimum pressure" column ndicated "atmospheric". It is assumed this fourth outage is also draindown.

(c) T(B2) = T(B) - T(BO) - T(B1) - T(B5) - T(B6)

where T(B) = Total time in Case C shutdown (refueling outage) from Ref. 6, Table 3-1.

$T(B2)_{05} = T(B)_{MIN} - T(BO)_{05} - \ldots$

$T(B2)_{50} = T(B)_{AVG} - T(BO)_{50} - \ldots$

$T(B2)_{95} = T(B)_{MAX} - T(BO)_{95} - \ldots$

TABLE 9-3

SHUTDOWN DATA VARIABLES

(d) $T(C4) = T(C) - T(C0) - T(C1) - T(C2) - T(C3) - T(C5) - T(C6)$

where $T(C)$ = Total time in Case C shutdown (refueling outage) from Ref. 6, Table 3-1.

$T(C4)_{05} = T(C)_{MIN} - T(C0)_{05} - \ldots$

$T(C4)_{50} = T(C)_{AVG} - T(C0)_{50} - \ldots$

$T(C4)_{95} = T(C)_{MAX} - T(C0)_{95} - \ldots$

(e) F(A) is input as a three bin histogram with the following values and corresponding weights:

$F(A)_1 = 1.0 \quad WT_1 = 0.1$

$F(A)_2 = 2.8 \quad WT_2 = 0.8$

$F(A)_3 = 11.0 \quad WT_3 = 0.1$

These values are based on the following:

$F(A)_1$ = 1.0 non-drained maintenance outages per year - estimated

$F(A)_2$ = 2.8 non-drained maintenance outages per year - Ref. 6, Section 3.3.

$\left(\frac{\text{49 maint. outages - 4 drained outages}}{\text{16 plant years}} = \text{2.8 outages/yr}\right)$

$F(A)_3$ = 11.0 non-drained maint. outages per year - Ref. 1, Section 6.6.2.

The weights are subjectively assigned.

(f) F(B) is input as a three bin histogram with the following values and corresponding weights:

$F(B)_1 = 0.125 \quad WT_1 = 0.1$

$F(B)_2 = 0.25 \quad WT_2 = 0.8$

$F(B)_3 = 2.4 \quad WT_3 = 0.1$

TABLE 9-3

SHUTDOWN DATA VARIABLES

These values are based on data from Ref. 6, Table 3-4, as follows:

$F(B)_1$ = 1 event/8 years = 0.125 events/year - longest interval between drained outage at Zion (Ref. 6)

$F(B)_2$ = 4 events/16 years = 0.25 events/year - average interval between drained outages at Zion (Ref. 6)

$F(B)_3$ = 1 event/5 months = 2.4 events/year - shortest interval (Ref. 6)

(g) F(C) is input as a three bin histogram with the following values and corresponding weights:

$F(C)_1$ = 0.67 WT_1 = 0.1

$F(C)_2$ = 0.83 WT_2 = 0.8

$F(C)_3$ = 1.0 WT_3 = 0.1

These values are based on the following:

$F(C)_1$ = 1 refueling/18 months = 0.67 - longest interval between refueling outages at Zion (Ref. 6)

$F(C)_2$ = 12 refueling/16 plant years = 0.83 - average interval between refueling outages at Zion (Ref. 6)

$F(C)_3$ = 1 refueling/12 months = 1.0 shortest interval between refueling (Ref. 6)

(h) These data variables are computed from "basic" data variables using equations given in Section 9.2.

TABLE 9-4

PROCEDURAL EVENT TREE MISSION TIMES

	Average Mission Time (Hours)					
Case	Tree 1 Cooldown	Tree 2 RCS Drain	Tree 3 Refuel. Fill	Tree 4 Refuel. Drain	Tree 5 RCS Fill	Tree 6 Startup
A	295*	-	-	-	-	24
B	31	959* (X)	-	-	101	24
C	50	47*	161 (Y)	1438* (X)	193	72

Notes:

X = RCS drained to flange or hot leg.

Y = RCS filled to refueling level.

All other entries are Condition W = RCS filled.

Case A = Non-Drained Maintenance Outage. Time in Case A = T(A) = 319 hours per A outage.

Case B = Drained Maintenance Outage. Time in Case B = T(B) = 1115 hours per B outage.

Case C = refueling Outage. Time in Case C = T(C) = 1961 hours per C outage.

The total annual time in shutdown = T(SD) = F(A) * T(A) + F(B) * T(B) + F(C) * T(C)

= 1085 + 502 + 1628

= 3215 hours in shutdown per year

* Includes time in stable maintenance state.

10.0 CORE/CONTAINMENT RESPONSE AND CONSEQUENCE ANALYSIS

10.1 Core and Containment Response Analysis

10.1.1 Introduction

The core and containment response analysis addresses the physical progression of accident sequences from the time of loss of adequate core cooling to release of radionuclides from the containment. This analysis includes the effects of reduction in decay heat and radionuclide inventory from the time of plant shutdown to the time of the postulated accidents.

This analysis interfaces with the "front end", i.e., the plant model, through the definition of a set of plant damage states. (See Section 10.1.2). The end product of the containment response analysis is a set of release categories which define the timing and magnitude of radionuclide releases to the environment for a representative set of accident sequences. This set of sequences spans the full spectrum of scenarios that could result from accidents initiated at shutdown. The release categories constitute the endpoint of the containment analysis and the starting point of the consequence analysis task, which is described in Section 10.2. The relationship between major tasks is shown in Figure 10-1.

By grouping accident scenarios into plant damage state "bins" and then into release category "bins", the many thousands of plant failure scenarios can be efficiently analyzed from initiation to the point of health effects risk. The number of bins are chosen to assure a reasonable degree of similarity among the scenarios assigned to a given bin, while keeping the number of different bins to a manageable level.

The core and containment response analysis is based on the results of the evaluation of accident progression from full power contained in the SSPSA (Reference 1) with appropriate corrections to account for reduced decay heat, reduced radionuclide inventory, and reactor coolant system modes unique to plant shutdown. Specific differences for accidents initiated during shutdown were identified and used to modify the SSPSA results. Due to the low initial decay heat level, the time intervals between accident initiation and onset of severe core damage are generally longer than for power operation events. This affects the definition of plant damage states for shutdown. For the same reason, the timing of the releases after core damage is stretched out over longer time intervals. For initially isolated containment sequences, the time to containment failure is so long (if at all) that these sequences were modeled as containment intact with only design basis leakage.

Finally, the containment is permitted to be unisolated during shutdown, including conditions in which the containment hatch is removed. Thus, the treatment of containment isolation failure tends to be more important in relation to the treatment of ultimate containment pressure capacity compared to the case with power operation events. Containment isolation reliability is analyzed in Section 10.1.3.

10.1.2 Definition of Plant Damage States

The plant damage states for shutdown accidents are defined in terms of parameters important to containment performance and the radionuclide source term released. These parameters are as follows:

- o The pressure inside the reactor coolant system (i.e., pressure vessel) at the time when core damage occurs for cases when the RCS is initially closed. A high primary system pressure up to the time of vessel failure creates the conditions where, if the containment is initially isolated, high RCS pressure could increase the potential for direct containment heating or induced SG tube rupture. If the containment is initially not isolated, high RCS pressure will provide a driving force to sweep out fission products.

- The presence of a substantial depth of water in the reactor cavity underneath the pressure vessel. The absence of water in the cavity would allow concrete basemat attack by the molten core debris resulting in additional fission products transported into the containment atmosphere as well as higher core debris temperatures to support oxidation, increasing the amount of fission products released.

- The status of containment boundary at the start of core melt - isolated or non-isolated with various size opening possibilities ranging from small penetrations to an open equipment hatch.

The matrix defining the plant damage states for core damage sequences at shutdown is presented in Table 10-1. The plant damage state designations are of the form:

RJX

where:

R denotes the accident initiated with the plant in Modes 4, 5, or 6 while on RHR.

J is an integer from 1 to 6 that defines the combination of RCS pressure and RV cavity water state, i.e.,

1 = Low pressure, Wet cavity,
2 = Low pressure, Dry cavity,
3 = Medium pressure, Wet cavity,
4 = Medium pressure, Dry cavity,
5 = High pressure, Wet cavity,
6 = High pressure, Dry cavity,

X is a letter (D, P, F, or H) that defines the status of the containment boundary, i.e.,

D = Containment penetrations isolated,
P = Containment penetrations open less than 3" dia.,
F = Containment penetrations open between 3" and 18" dia.,
H = Containment hatch open.

In selecting possible values of the containment boundary designator, the codes D, P, and F correspond with the equivalent power operation plant damage states codes D, FP, and F. (See Section 11.4 in the SSPSA - Reference 1). Note that the power operation plant damage states codes A, B, and C are not used here. These states require operation of containment sprays or fan coolers. Those systems are conservatively ignored in the shutdown events study because of the emphasis placed on early release scenarios and because they are normally taken out of service when the plant is in Modes 4, 5, or 6. In addition, the accident response model was simplified by combining the F state with the H containment boundary state.

The RCS pressure was separated into three categories as compared with two in the power operation events analysis to account for three different types of scenarios that were identified in the shutdown events analysis. Low pressure scenarios can occur when the RCS is open with the RV head or Steam Generator manways off or as a result of a large or medium LOCA. Medium pressure can occur during scenarios in which the degree of RCS pressurization following core heatup is limited by operation of the RHR relief valves inside the containment whose pressure setpoint is 450 psig. In order to have these medium pressure scenarios, it is necessary to postulate failure or unavailability of the automatic isolation of the RHR from the RCS at 660 psig. This is accomplished via closure of redundant AC motor operated valves in each RHR hot leg suction path and through pressure closure of redundant check valves in each RHR cold leg injection path. When this automatic isolation functions properly, or when the RHR is initially isolated, RCS repressurization following core heatup can rise up to the normal power operation setpoint of the pressurizer PORVs, giving rise to high pressure scenarios. The lower boundary of the high pressure range (700 psia) was selected based on a conservative assessment of the minimum pressure that could cause direct containment heating. This value is also the maximum pressure rise for the sequence involving loss of RHR with the RCS full and the RHR not isolated. (See Appendix B, Figure 5).

Each sequence in the accident event trees was assigned to a particular plant damage state according to the conditions imposed by the initiating event and the particular combination of events defined by the event tree. The following rules were used in the plant damage state assignments.

- o All the initiating events that enter the accident event trees in either a Condition X (RCS opened, drained) or Condition Y (RCS opened, refueling level) are low pressure scenarios. For these scenarios, the opening in the RCS is assumed to be of sufficient size to prevent repressurization due to heatup.
- o All LOCA initiating events which are not isolated are assumed to be low pressure scenarios. The LOCAs with RHR isolated are assumed to be high pressure scenarios and are modeled like loss of RHR sequences in Condition W.

- o W scenarios are assumed to e high pressure scenarios. This assumption of high pressure is based on the expected plant response upon RCS pressurization. The RHR isolation valves will close at 660 psia and the automatic setpoint feature of LTOP will function properly by tracking the increasing RCS temperature upward until the normal power operation setpoint of the PORVs is reached. Neglecting the possibility for other medium pressure scenarios is conservative because the high pressure plant damage states will generally have higher consequences due to larger source terms and reduced release durations.

  Note that scenarios that occur in a W condition (RCS closed) and are caused by a total station blackout would actually be medium pressure because the motor operated RHR isolation valves would not close and the RHR relief valves would maintain pressure around the 450 psig setpoint or less. However, it was determined that these scenarios are much less likely than high pressure scenarios with corresponding containment states. To simplify the plant model, it was conservatively assumed that these medium pressure scenarios are high pressure scenarios.

- o All scenarios are assumed to result in a dry reactor cavity except for LOCA sequences caused by failure of the reactor cavity seal. Note that in the power operation mode, wet reactor cavity conditions are assumed to occur only when the RWST is injected into the containment. In shutdown, the containment spray system is isolated and the safety injection signal is disabled. Neglecting the possibility of a wet cavity through operator action is conservative with respect to the fission product source term released to the containment atmosphere.

All procedural event tree initiators are designated as occurring in either Conditions L (LOCA), W (RCS filled), X (RCS drained), or Y (RCS at refueling level). According to the above rules, Conditions L, X, and Y are all low pressure and Condition W is high pressure. The reactor cavity seal failure sequences (initiator L5) are the only sequences that are guaranteed to be "wet", i.e., the reactor cavity is full. All other scenarios are conservatively assumed to be "dry" scenarios.

All the non-procedural initiators are assumed to occur at Condition X, RCS drained and opened, (e.g., $LOSP_X$) or at Condition W, RCS filled and intact (e.g., $LOSP_W$). The probability split between X and W was determined based on the relative amount of time spent in these conditions. Based on the above rules and assumptions, only 9 of the originally defined 24 plant damage states were actually used, as indicated in Table 10-1.

10.1.3 Containment Response Analysis

The Seabrook Station containment has been evaluated extensively in the SSPSA (References 1 and 22). Structural integrity was evaluated in detail in Section 11 of the SSPSA (Reference 1). This evaluation found that the Seabrook containment could withstand internal pressure well beyond the design basis pressure. The time to containment failure due to overpressure following a core melt with no containment cooling would be very long. The pressure capacity of the containment is inherent to the structure and is not affected by the plant in shutdown. In the shutdown mode, the decay heat is lower than for the plant at power and thus the time to overpressurization due to decay heat loads with no containment cooling would be even longer. This longer time allows recovery actions to restore electric power (if necessary) or to provide alternate means of containment cooling. Thus, the containment overpressurization mode of failure for the plant in shutdown is conservatively modeled by the plant at power. No unique aspects of shutdown have been identified which have direct bearing on containment structural integrity, apart from a higher frequency of non-isolation, which is emphasized in this study.

External events that could fail containment due to structural damage from aircraft, turbine missiles, or earthquakes were also considered in the SSPSA and found to be very unlikely. This conclusion applies equally at shutdown.

Containment isolation is not required most of the time by Technical Specifications in shutdown Modes 5 and 6. Also, operator actions are required to isolate containment because automatic signals are disabled. Section 10.1.4 describes containment isolation and the probability that a small or large opening in containment exists after core melt.

The potential for early containment structural failure due to loads such as direct containment heating is discussed in Section 10.1.5.

10.1.4 Containment Isolation Analysis

Containment isolation is not required by Technical Specifications (see Appendix C) for Mode 5 (Cold Shutdown) and for Mode 6 (Refueling) except during core alterations or movement of irradiated fuel. The operators would have time to isolate manually from the Main Control Board (MCB) or locally close the containment isolation valves due to the long time available in most core damage sequences before a significant release. Procedures and training, in general, alert the operator to the importance of containment isolation. Abnormal Procedure OS1252.03, Rev. 1 "Area High Radiation" instructs the operator to verify containment ventilation isolation in response to a containment radiation alarm. In the event of high radiation which made the containment unhabitable, operators could locally close outside isolation valves in each penetration if necessary.

The only exception to the simple and quick isolation of containment penetrations is the case of an open equipment hatch, which could occur in Modes 5 and 6. Replacing the equipment hatch could require several hours or more and would require tasks to be performed from inside containment. Estimates of the time to close and secure the hatch range from 4 to 12 hours. New administrative controls to assure reliable containment isolation during Modes 5 and 6 were identified in this study and are summarized below. These controls are assumed to be in effect in the quantification of containment isolation reliability.

o Equipment Hatch

1. The equipment hatch will be removed only if the RCS is closed and steam generator cooling is available; or if the refueling cavity is full.

2. The hatch will be replaced as soon as the transfer of equipment and/or spare parts is completed.

3. A polar crane operator will be immediately available for any duration that the hatch is off.

o Personnel Airlock or Emergency Airlock

1. One door on each airlock will be capable of closure at all times.

o Containment Isolation Valves

1. One train of COP and CAP valves will be capable of closure from the control room at all times.

2. Administrative controls will be in place to assure that operators maintain awareness of the current status of each containment isolation valve shown in Table 16.3-4 of the Technical Requirements Manual. (e.g., isolation valves out of service due to maintenance, manual isolation valves open).

All containment penetrations were reviewed to determine which have the greatest potential for being open. Table 10-2 summarizes this evaluation of containment isolation valves. In addition, the following penetrations were identified as potential large containment openings: equipment hatch, emergency airlock, personnel airlock, and fuel transfer tube.

Two categories of containment isolation are modeled as top events in the plant response model. These two top events, EH (equipment hatch and large openings) and SP (small penetrations), are discussed below.

EH - Large Openings

The 8-inch online purge valves and the 36-inch containment purge valves identified in Table 10-2 are included in this category as well as the personnel air lock, the emergency air lock (in the equipment hatch), the equipment hatch itself, and the fuel transfer tube. The equipment hatch, 36-inch purge lines and 8-inch purge lines were found to dominate the containment unavailability for large openings. The estimated unavailabilities of top event EH for different initiating event types is documented in Table 10-3.

Equipment hatch status (on or off) is the most important information in this category because of its size, the length of time required for restoration, the need for offsite power, and the fact that it provides a direct unfiltered release path. The administrative controls assumed in this analysis require outage preplanning such that the hatch is only removed when the RCS is closed and filled with steam generator cooling available or when the refueling cavity is full, and is replaced as soon as the transfer of required equipment and/or parts is completed. A dedicated polar crane operator is assumed to be immediately available during those times when the equipment hatch is removed. There measures minimize the time that a direct release pathway is available.

The equipment hatch must be taken off at least every four refuelings to bring in reactor vessel O-ring seals. (A supply of four is stored within containment to be used whenever the head is removed). The hatch will also be removed whenever it is necessary to bring in test or repair equipment or spare parts which are too large or too heavy to be brought in manually through the personnel hatch.

With power available, it would take at least 4 hours and possibly longer to reinstall and secure the hatch based on conversations with Operations and Maintenance personnel at Seabrook. Because there is presently no supporting data, it is assumed that the range could be run as high as 12 hours. This action might be impeded by high level of stress and degraded containment environment - high temperature and/or high radiation. The probability of the operator failing to restore the hatch (OP_{EH}) is quantified in Section 6.4.2 and is used in Table 10-3.

These observations led to the identification of the need for administrative controls discussed above.

To restore the hatch requires use of the polar gantry crane. This crane is powered off non-safety 480V Bus 11 so that it becomes unavailable during a loss of offsite power event. It is possible to backfeed Bus 11 through a UAT with power from an emergency diesel. The crane electric load is 325 kVA which is not a large load for the diesel. However, to perform this action would require a potentially difficult accident management decision to add this further load to the diesel as well as the time to mechanically bypass protective interlocks. Thus, without offsite power, it is assumed that the hatch cannot be restored to closed position.

The personnel air lock and the emergency air lock (in the hatch) are administravely required to be always capable of closure (at least one door).

Administrative requirements for containment ventilation systems status are straight forward: one train of CAP and COP line must be capable of isolation from the control room at all times. Operator failure to close the COPs and CAPs is quantified in Section 6.4.2 (OP_{FL}) and is used in table 10-3.

During refueling, with the fuel transfer tube open, containment isolation is required by Technical Specifications (fuel shuffling). Only the fuel transfer valve and purge valves would likely require closing. The fuel transfer tube valve is a manual valve controlled from the spent fuel pool operating floor. The other isolation is a blank flange inside containment which is removed during refueling. Failure of this valve to close on "demand", i.e., stem binding, etc., is comparable to the SSPSA data variable for MOV failure to close on demand while showing closed. This failure rate mean value is about 1.0E-4. Also, this valve is open only a small fraction of the shutdown period and could easily be closed from the spent fuel building. Thus, it is judged to be an insignificant contributor to EH.

SP - Small Openings

The availability of containment isolation for all other penetrations is included in top event SP. It is assumed that this is dominated by operator action to fail to isolate all penetrations rather than hardware because of multiple isolation valves in each line. The key to ensuring confidence that all small penetrations (see Table 10-2) are either closed or will be closed after an abnormal event is the administrative control requiring the operators to maintain awareness of the current status of each isolation valve. The estimated unavailability of top event SP is based on operator failure documented in Section 6.4.2 (OP_{SP}) and is used in Table 10-3.

10.1.5 Shutdown Event Release Categories

The plant damage states defined in Table 10-1 covers 24 possible states from which 9 were actually used in the analysis. These 9 can be grouped as follows:

Type 1 States: R1D, R1P, and R1H

Type 2 States: R2D, R2P, and R2H

Type 6 States: R6D, R6P, and R6H

For each sequence type, the physical conditions affecting source terms are identical, except for the state of the containment boundary at the time of core damage. P[illegible] the states with the letters P and H have containment failure im[illegible] [illegible]lant damage state frequencies provide a lower bound on [illegible]bility of containment failure. The conditional probability of a large opening in the containment based on the plant damage state, given a type 1 shutdown event occurs is, for example:

$$F(R1H|\text{Type 1 event}) = \frac{F(R1H)}{F(R1H) + F(R1P) + F(R1D)}$$

$$= \frac{2.6(-10)}{2.6(-10) + 2.4(-9) + 5.4(-8)}$$

$$= .005$$

Similarly for events of Type 2 and 6, we have

$$F(R2H|\text{Type 2 event}) = \frac{F(R2H)}{F(R2H) + F(R2P) + F(R2D)}$$

$$= \frac{4.6(-7)}{4.6(-7) + 1.5(-6) + 3.9(-5)}$$

$$= .01$$

$$F(R6H|\text{Type 6 event}) = \frac{F(R6H)}{F(R6H) + F(R6P) + F(R6D)}$$

$$= \frac{1.0(-7)}{1.0(-7) + 1.3(-7) + 4.6(-6)}$$

$$= .02$$

A similar approach can be followed to compute the lower bounds on the conditional probabilities of a small opening in the containment given each type of release.

$$F(R1P|\text{Type 1 event}) = \frac{2.4(-9)}{2.6(-10) + 2.4(-9) + 5.4(-8)}$$

$$= .042$$

$$F(R2P|\text{Type 2 event}) = \frac{1.5(-6)}{4.6(-7) + 1.5(-6) + 3.9(-5)}$$

$$= .037$$

$$F(R6P|\text{Type 6 event}) = \frac{1.3(-7)}{1.0(-7) + 1.3(-7) + 4.6(-6)}$$

$$= .027$$

Hence, no matter what happens in the containment, the conditional probability of a containment failure due to inadequate isolation alone is on the order of 10^{-2} for gross leakage to a few percent for small open penetrations.

The release categories previously defined fo. the Seabrook plant (References 1 and 2) for power operation events consider the following type of containment release for severe core damage events:

S_1 = early gross failure of the containment

S_2 = early high leakage with subsequent overpressurization

S_3 = early low leakage with subsequent overpressurization

S_4 = basemat melt through

S_5 = long term intact containment

S_6 = failure to isolate containment on-line purge.

S_7 = RHR pump seal interfacing LOCA.

For shutdown event plant damage states with containment boundary type D (originally isolated), it is conceivable (though not very likely) that the containment could fail due to direct containment heating or other pressure loads resulting in a release condition similar to S_1 or S_2 depending on the size of the containment breach. However, it was shown in Reference 22 (PLG-0550) for power operation events that the probability of early containment failure due to early loads such as direct containment heating is on the order of 10^{-3} to 10^{-4}. In the SSPSA, the probability of an early intact plant damage state developing into a containment failure release of type S_1, S_2 or S_6 due to a wide variety of mechanisms such as other excessive pressure loads, steam explosion, hydrogen burns, etc., was found to be in the range of 10^{-4} to 10^{-6}.

There is no reason to suspect that the phenomenological containment failure probabilities would be any greater than with power operation events. In fact, we would expect, if they are any different at all, they would be less frequent due to a slower evolution of physical phenomenona due to lower decay heat. Hence, while it is possible that a type D (isolated) plant damage state could develop into an S_1, S_2 or S_6 type of early containment failure, such a scenario would have a mean frequency of 2 to 4 orders of magnitude less than a corresponding scenario with an H designator. The corresponding scenario for the type H sequence is guaranteed to have a source term and consequences at least as severe and therefore its risk contribution would fully dominate the scenario starting as a type D. Hence, it is not necessary to develop a containment event tree that tracks the propagation of a type D scenario to a containment failure release category.

It is known from previous analyses that plant damage states with the designator P is best described by an S_2 type of release where the containment degradation due to inadequate isolation of the containment is inferred by the designator. It is possible that a type P scenario could develop into an S_1 or S_6 type of release due to containment phenomenona described above. However, the conditional probability of such a transition is very low (i.e., 10^{-3} or less) in comparison to the relative likelihood of type H or type P states.

For the above reasons it was determined that, for shutdown events, it is not necessary to perform a containment event tree analysis of the form needed to map from intact (D) or high leakage (P) plant damage states to more severe containment failure modes. It is only necessary to develop an appropriate set of source terms for each shutdown plant damage state that assumes the containment isolation status inherent with the plant damage state. These source terms are described in the section below. To make up release category designators, the prefix "S" is added to the plant damage state designator. Hence, the release category associated with plant damage state R1D has the designator SR1D followed by a code to identify either realistic (R) or conservative (C) source term assumptions.

10.1.6 Shutdown Event Source Terms

The approach adopted to estimate source terms for various release categories was to make adjustments to source terms previously analyzed for power operation events, to account for reduced decay heat and lower fission product inventories associated with shutdown scenarios.

The methodology used to derive the source terms is based on Engineering judgment and deduction to find which existing power source term is analogous to each of the shutdown cases. Then, since the major release driving forc, is the decay energy (which is considerably lower in shutdown cases), the release times are evaluated assuming the same energy amounts are needed for corresponding, discreet points along the scenario, and correcting for different initial thermal conditions. Finally, the release fractions are adjusted to the input requirements and the assumptions of the CRACIT model (Calculation of Reactor Accident Consequences Including Trajectory - See SSPSA Section 12, Reference 1).

The following is a brief description of how the source terms were categorized, adopted, and calculated for CRACIT input.

Review of Plant Damage State Definitions

As described in the previous section, the release categories for the shutdown cases are related one-for-one to the plant damage state. The release categories are identified by a five character alphanumeric designator starting with the letters "SR" where the "S" has been added to the corresponding plant damage state. As with plant damage states, the third and fourth characters designate the reactor state as described in Section 10.1.2 and Table 10-1. The last letter refers to a conservative case ("C"), or to a realistic case ("R").

Consequently, 18 source terms ar[illegible] to cover two cases each for 9 release categories:

SR1D-C	SR2D-C	SR6D-C
SR1D-R	SR2D-R	SR6D-R
SR1P-C	SR2P-C	SR6P-C
SR1P-R	SR2P-R	SR6P-R
SR1H-C	SR2H-C	SR6H-C
SR1H-R	SR2H-R	SR6H-R

Derivation of Shutdown Source Terms from Power Source Terms

The shutdown release categories with their analogous power release categories are listed in Table 10-4. All shutdown cases are assumed to have failed containment spray systems. This corresponds to the bar atop the release category designator for the power release category. (e.g., $\overline{S3}$). Cases SR2D/P/H, and SR6D/P/H are modeled as dry reactor cavity cases and, thus, they all have source terms with a vaporization term (designated "V" in the power release categories).

The shutdown cases with early containment leakage (SR1P, SR2P, SR6P) correspond by definition to the S2 power release category. The intact containment cases (SR1D, SR2D, SR6D) similarly correspond to the S3 category and an openhatched containment (SR1H, SR2H, SR6H) corresponds to the S6 category.

Release Times Evaluation Based on Decay Power

The accident start times for the shutdown events are input from a separate evaluation provided in the next section. The time to start of release was assumed to be the time to reach 1200°F core outlet steam peak temperature. This time was calculated by the following integral decay heat functions (based on ANS 5.1 (1979) standard):

$Q\ [BTU] = 2.46 \times 10^8 (t_2^{0.835} - t_1^{0.865}) \qquad 0 \leq t \leq 1/9$ hr.

$Q\ [BTU] = 2.34 \times 10^8 (t_2^{0.718} - t_1^{0.718}) \qquad 1/9 \leq t \leq 5555.5$ hr.

where t, t_1, t_2 designate the times (in hours) after shutdown along the decay heat curve.

The above formula was used as follows: first the amount of decay heat generated between start of accident ($t_1 = 0$) and start of release (t_2) in the power case was found: (Q). Then, introducing t_1 as the start time of the shutdown accident (the number of hours after shutdown), the value t_2 was calculated so the amount of decay heat between t_1 and t_2 was the same value, Q.

The following corrections were applied to the above calculation process:

1. The initial thermal conditions of the shutdown cases vary from the power cases: the temperature of the Reactor Coolant System is lower and when the RCS is vented and drained down, there is less water in the RCS. Adjustments were made to correct for this based on energy considerations. For the SR6D/P/H cases these corrections are not given explicitly so the corrected times from accident start to 1200°F at the core exit were evaluated as 8.25 hr for the conservative case and 17 hours for the realisti. case.

2. since it is assumed that in shutdown events the metal water reaction is 50% effective, while only 20% effective in the power events, the corresponding heat amount (3.25×10^2 BTU) was added to the decay heat in the shutdown events.

<u>Source Term Adjustments to CRACIT</u>

The following adjustments were made:

1. For puff releases that start prior to evacuation time and last after it, two separate puffs were modeled in order to provide more realistic simulation of the evacuation effect. The time of issuing an evacuation warning was assumed to be one hour after accident initiation.

2. To provide source terms that are compatible with the assumption built into CRACIT regarding the calculation of ground shine dose, all releases longer than 24 hours

were truncated so that only the first 24 hours of the release are considered.

3. Due to CRACIT input specifications, time durations between two consecutive puffs were rounded to integers.

4. Cases SR1D, SR2D, SR6D (intact containment) were assumed to have an overpressurization puff, maintaining the same short release durations as in the power events.

Shutdown Source Terms Listing

The time histories for each shutdown case (preceded by the time history of the analogous power case) are provided in Table 10-5. A complete history of all source term information is provided in Table 10-6. The times used for the "Start of Accident" in Table 10-5 were obtained using the assessment of source term uncertainties described in the following section. In general, the Start of Accident time for each realistic source term is the mean value of the start time distribution, and the start time for the conservative source term is a low percentile (e.g., no greater than the 20th percentile) of the start time distribution. The start time distributions are described at the end of Section 10.1.7.

10.1.7 Treatment of Source Term Uncertainties

Uncertainties in the development of source terms were quantified by defining a discreet pair of complete source term vectors for each release category, using a procedure similar to that employed in RMEPS (Reference 2). Each vector contains a single set of release fractions, release times and energies, and warning times needed to produce one execution of the CRACIT consequence model. One source term vector is defined to represent a realistic case and another to represent a conservative case. In the final "best estimate" results, probability weights of 0.9 and 0.1 are placed in the realistic and conservative source terms, respectively as was done in RMEPS. Sensitivity results are also presented in which all the weight is placed on the conservative source terms.

Conservative source terms are based on WASH-1400 source term methodology. These source terms were originally calculated in the SSPSA using the MARCH/CORRAL series of codes for power operation events, and converted for shutdown conditions using the methodology described in the previous section. Realistic source terms were based on the most realistic source terms available from the SSPSA or RMEPS and, again converted to shutdown conditions.

There is a particular source of uncertainty that is especially important for shutdown events that is much less important for power operation events. That source is the uncertainty in the timing of the releases due to such uncertainties as how long after shutdown the accident occurs and key factors about the degraded status of equipment and systems that dictate the temporal evolutions of the accident. The special treatment of uncertainty in time of release is explained below.

The uncertainty in time of release as measured from the time since power operation is a function of the time at which the loss of core cooling transient initiates and the configuration of the plant when the transient occurs. The shutdown events study considers three principal plant configurations which are associated with different RCS status designators: "W" for RCS filled and RCS pressure boundary intact; "X" for RCS drained to between RV head flange and RCS piping midplanes; and "Y" for RCS filled to refueling level. The time of accident initiation is dependent on the duration of the particular outage within which the sequence occurs and the time required to complete each preceding procedure prior to event initiation. These times are in turn dependent on the tasks to be completed during the outage and variations in operator performance in the completion of the tasks. Key factors of the plant configuration such as RCS boundary open or closed, availability of steam generators, and RCS water level determine the time available for recovery actions during the transient and the time delay between initiation of the transient and core damage for sequences of interest in which recovery actions are unsuccessful.

The uncertainty in time of release was quantified for the four key release categories by determining the fraction of the corresponding plant damage state frequency that was initiated in each of the 6 possible shutdown procedure event trees. The variation of the residence time in each procedure tree, about the fixed values of those residence times assumed in the point estimate results, is accounted for in determining the fractional contribution to each plant damage state. A breakdown of the procedure tree fractional contributions to each plant damage state is shown in Table 10-7. This matrix was constructed from the MAXIMA output files that contain the results of the procedural event tree and accident event tree quantification.

In general, the total time between departure from power operation to core uncovery for a sequence initiating in the Kth procedure of the outage is given by:

$$T = T_{RI} + \sum_{j=1}^{K-1} T_j + T_k^* + t_{sg} + t_{cu}$$

Where

T_{RI} = Time to initiate RHR (time from beginning of plant shutdown until Mode 4 is entered)

$\sum_{j=1}^{K-1} T_j$ = Time to complete the first K-1 procedures during the outage

T_k^* = A random point in time during the T_k hours of the Kth procedure during the outage at which time the event is assumed to begin

t_{sg} = The time to boil dry the steam generators from the time of event initiation (for RCS Condition W only)

t_{cu} = The time to uncover the core as measured from SG boil dryout time for type W conditions or from event initiation for type X conditions.

The time to accident initiation, T_{AI}, is given by the sum of the first 3 terms in the above equation:

$$T_{AI} = T_{RI} + \sum_{j=1}^{K-1} T_j + T_k^*$$

In the above formulation, t_{sg} and t_{cu} are dependent upon the time of accident initiation.

$$t_{sg} = f(T_{AI})$$

and $$t_{cu} = f(T_{AI} + t_{sg}) \text{ for type W conditions}$$

$$= f(T_{AI}) \text{ for type X or Y conditions}$$

For example, the total time to core uncovery for events initiating in procedure tree A6 and condition W is given by:

$$TA6W = TA6S + t_{sg} [TA6S] + t_{cu} [TA6S + t_{sg} (TA_{6S})]$$

Where

$$TA6S = T_{RI,A} + \sum_{j=1}^{5} T_{Aj} + T_{A6}^*$$

Note that the actual time within the procedure tree at which the event initiates, T_{A6}^* is a random variable in the interval $[0, T_{A6}]$ where

T_{A6} is the duration of the procedure tree. In many cases, the event initiates as a result of RHR failure over a mission time taken to be the total duration of the procedure tree. The uncertainty in the event initiation time stems from two independent sources: The variation in the duration of each procedure up to and including the procedure in which the event occurs and the random time of failure within the total duration of that procedure.

For a given plant damage state (or corresponding release category), the sources of uncertainty in the time from power operation to core uncovery are summarized as follows:

- Time of RHR (Mode 4) Initiation -

  The actual time from 100% power to RHR initiation (entering Mode 4) varies and is dependent on type of shutdown (A, B or C).

- Procedure Duration -

  For a given procedure tree there is a variation in duration due to variation in the tasks to be accomplished and the performance of specific tasks.

- Time of Initiation -

  There is a random variation in the actual time of accident initiation within a procedure tree.

- Time of SG Boilout -

  There is variation in time to SG Boilout due to number and condition (e.g., temperature, pressure and level) of steam generators and previous history of power operation that determines decay heat.

- Time of Core Uncovery -

  Variations in primary conditions (temperature, pressure and level) affect the time to core uncovery.

- o Modeling Uncertainty -

  The thermal-hydraulic models used to predict SG Boiloff and core uncovery times (t_{sg} and t_{cu}) contain uncertainties.

- o Binning Uncertainty -

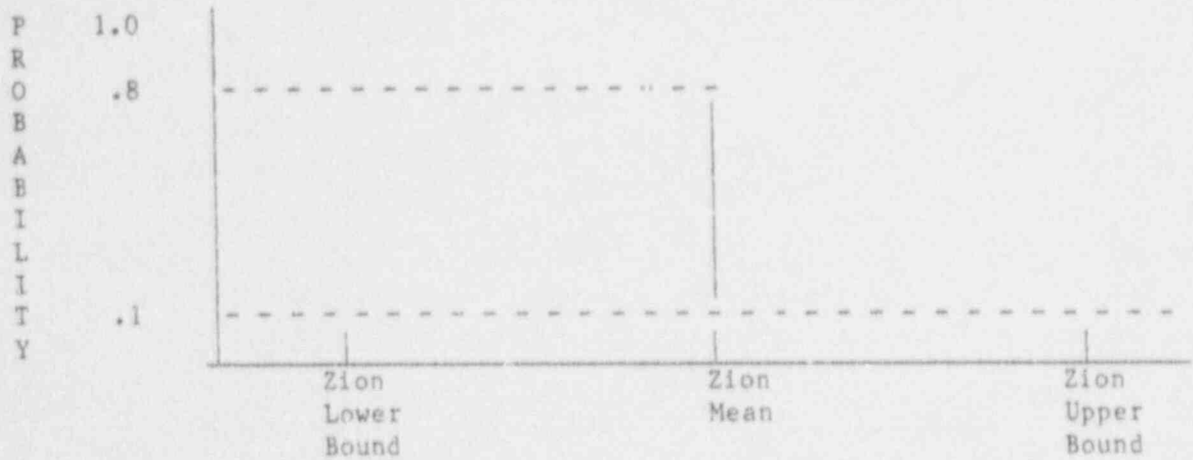
  Individual sequences contributing to a specific plant damage state may be initiated in various procedure trees. Thus, the fractional contribution from each procedure tree to the total plant damage state frequency is a source of uncertainty.

Uncertainties in the time to core uncovery for individual plant damage states were quantified by Monte Carlo error propagation using the STADIC4 computer code (Reference 23). The Fortran subroutines used to determine the output variables are presented in Appendix F. These subroutines relates the core uncovery times to the basic independent variables that represent the root sources of uncertainty. A total of 25 input variables were defined to characterize time uncertainties including; one for each of the 12 procedure tree durations; three for time from 100% power to initiation of RHR, i.e., one for each type of outage (drained maintenance, nondrained maintenance, refueling); four for the binning uncertainty of the 4 important plant damage states; one for thermal hydraulic modeling; one for initial water level in the RCS; one for a random variable for the time of initiation within a particular procedure tree; and three to represent the annual frequency of each outage type.

Eighteen of these 25 uncertainty distributions, the times to RHR initiation, the annual frequency of each outage type, and the duration of each procedure tree, were quantified using Zion plant data reported in NSAC-84 (Reference 6) as discussed in Section 9 (Table 9-3). From this data, three values were obtained for each parameter.

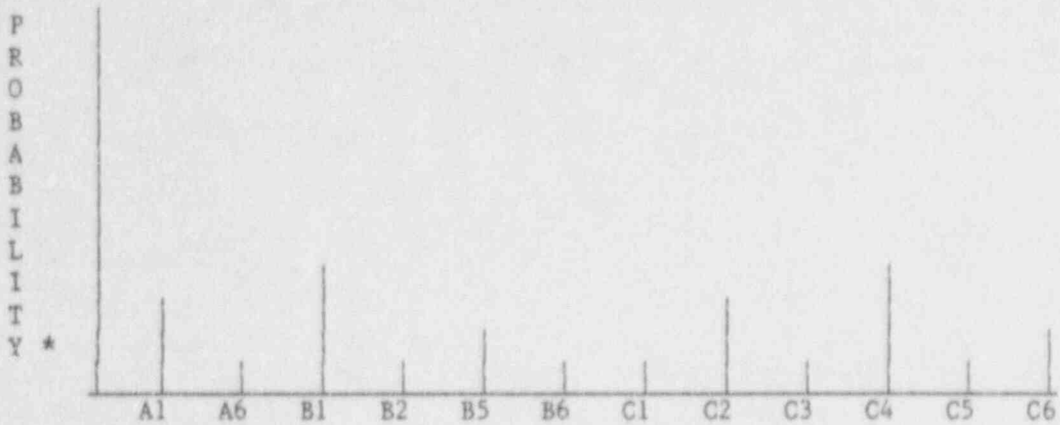
- o Lower Bound (smallest observed duration)
- o Mean (average of observed durations)
- o Upper Bound (largest observed duration)

This data was used to construct simple 3-point discrete distributions to characterize the uncertainty in the parameter value for Seabrook as follows:



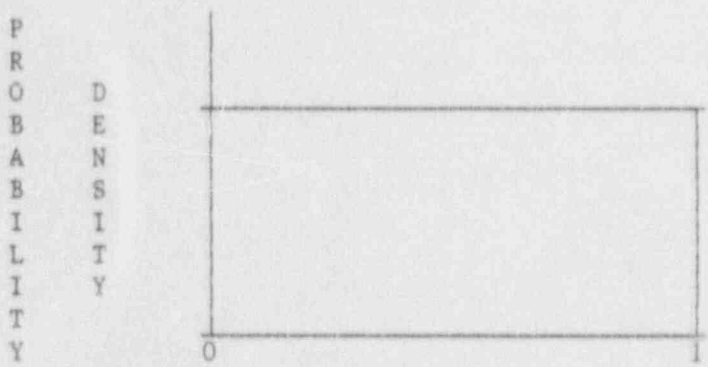
Because of the fact that the above procedure resulted in skewed right, asymmetrical distributions, the means of the distribution are generally greater than the means of the data. Hence, the uncertainty assumed is greater than the variation in the data and this tends to account for the additional source of uncertainty due to plant to plant variability in the application of Zion data to Seabrook.

To account for the binning uncertainty for procedure tree fractional contribution to plant damage states frequency, Table 10-7 was used to construct 4 different distributions one for each unique column of Table 10-7 of the form:



* not to scale

To account for the random initiation time, the constant RHR failure rate assumed in the plant event tree quantification is compatible with a uniform distribution over the duration of the procedure tree. Hence the distribution of the fraction of the procedure duration completed prior to initiation is a uniform distribution between 0 and 1.



Two additional sources of uncertainty were quantified: (1) the modeling uncertainty associated with estimating core uncovery times (EM) in Appendix B and (2) the initial water level (hot leg mid-plane or vessel flange) in the RCS (XL) for sequences initiated during X conditions. The model for core uncovery time is a 3-point discrete distribution similar to the above and the initial water level is a 2-point discrete distribution. The input variable uncertainty distributions (EM and XL) are provided in Appendix F.3.

Uncertainty distributions for accident initiation and core uncovery times for individual plant damage states were obtained by Monte Carlo by sampling fr each of the 25 input variable uncertainty distributions and using the ..fADIC4 subroutine SAMPLE to compute a corresponding set of output variable data. For each execution of SAMPLE, a random variable is selected for each of the 25 independent variables. Based on this information, the subroutine computes the time of event initiation and core uncovery times using the models and correlations developed in Appendix B. After repeating this procedure a large number of times (13,000 in this case), a pseudo data base of samples is created for each of the output variables. The code then constructs probability distributions to quantify the uncertainties in the output variables. Parameters of the accident initiation time distributions for each release category are presented in Table 10-8. The cumulative distributions are plotted in Figure 10-2. Intermediate results for each procedure tree are presented in Table 10-9.

To help determine warning times, a separate set of variables was defined to track the time interval between initiation and core damage. Cumulative distributions for 5 plant damage states, plotted in Figure 10-2, are representative of the 6 states. A single curve is provided for release categories R1H, R1P and R1D since all three of these plant damage states result from a single event, initiated only in procedure tree C3. Hence, no binning uncertainty exists for these plant damage states and the time to core uncovery for all three states is the same. As seen in this figure, the distributions span long time frames, several hundred hours for R1H and thousands of hours for the others. The reason why the distribution for R1H is distributed over shorter time frames than R2H and R6H can be explained in terms of Table 10-7. All of the R1H distribution comes from procedure tree C3, whereas the other plant damage states have contributions from 6 to 8 of the procedure trees. Hence, plant damage state R1H tends to result from events initiating during the early stages of a refueling outage whereas the remaining plant damage s es have significant contributions of early and late stages of all types of outages.

The uncertainty distributions for time to accident initiation (Table 10-8) are used to develop the source term time histories described in Section 10.1.6 (Tables 10-5 and 10-6).

In this study, preliminary results for the accident initiation times were used to generate the source term time histories and the final accident initiation times were checked to ensure that the final results were reasonably represented by the preliminary results. As a result of this approach the source term time histories shown in Tables 10-5 and 10-6 correspond with different percentiles of the final uncertainty distribution parameters shown in Table 10-8.

A comparison between the results of the uncertainty distributions for accident initiation time and the values assumed in the source term analysis is presented in Table 10-10. First it should be noted that the only release categories that contribute significantly to risk are SR2P, SR2H, SR6P and SR6H. It can be determined from the accident frequencies and release fractions that each of the SR1 categories is bounded by the corresponding SR6 category. In addition, all the type "D" (Containment Intact) categories have no potential for significant offsite doses within more than 24 hours of the release.

The accident initiation times that were used for the "realistic" source terms and resulting consequence analysis are seen to be consistently less than the distribution means for all 4 risk significant release categories. The amount of conservatism in the assumed "realistic" values range from about 4-1/2 days for SR6P to more than 2 weeks for SR2H. The value assumed for SR1-D, P and H was about 10 days <u>greater</u> than the distribution mean and, while this is non-conservative, it is unimportant due to the risk shadowing exhibited by the corresponding SR6 release categories.

The accident initiation times assumed for the "conservative" source terms are in all cases bounded by the 20th percentile of the corresponding uncertainty distribution. This is considered reasonable because those times are used in conjunction with release fractions that were independently derived from relatively short time frame scenarios.

It should be noted that the calculated distribution of accident start times for plant damage state SR2H is somewhat unrealistic since it is very unlikely that the equipment hatch would be removed (as required for plant damage state R2H) in less than 48 hours following operation at 100% power. However, the calculated distribution gives a 10th percentile value of 47 hours for accident initiation time. If it were assumed that the hatch were not removed within 48 hours of 100% power operation, the value of 90 hours used to develop the conservative source term case would probably fall below the 10th percentile of the start time distribution.

As noted in the above discussion of source term R2H, the calculated distribution of accident start times for plant damage state R6H is somewhat unrealistic since it is very unlikely that the equipment hatch would be removed in less than 48 hours following operation at 100% power. However, the calculated distribution gives a 10th percentile value of 28 hours and a 20th percentile value of 40 hours for accident initiation time if it were assumed that the hatch were not removed within 48 hours of 100% power operation, the value of 34.2 hours used to develop the conservative source term is obviously a conservative value.

In RMEPS (Reference 2) the probabilistically weighted source terms were weighted as 90% for the realistic case and 10% for the conservative case. For the conservative case, release fractions were less than obtained using WASH-1400 source term methodology and release times were conservatively estimated using the methodology. In this study, we have adopted WASH-1400 methodology release fractions as the conservative case. Even though we have increased the level of conservatism in assignment of release fractions and independently combined these with less than 20th percentile release times, we have retained the practice of placing 10% weight on the conservative source term. This simplifies the analysis and introduces a conservatism with respect to a more rigorously propagated source term uncertainty analysis.

In view of the large spread of accident initiation times incorporated into the analysis from the Zion operating data, a sensitivity analysis was performed to bound the effects of this particular factor. This sensitivity analysis was performed by selecting an accident initiation time that puts a lower bound on these times and by developing a source term corresponding to this time for the released category that produces the greatest numbers of consequences, SR6H-C. An accident initiation time of 20 hours after plant shutdown was selected as being much less than any reasonable time for initiation of an accident in Modes 4, 5, or 6 with the equipment hatch off. In order to meet the conditions necessary for an SR6H-C event, the following steps must be completed with a conservative estimate on the minimum time needed to complete each step:

		Minimum Time
1.	Shutdown the plant and enter Mode 4	10 hrs
2.	Enter Mode 5 (necessary to be able to take off the hatch per Technical Specifications)	10 hrs
3.	Remove the hatch	4 hrs
		24 hrs

Next, conservative release fractions and a set of release times were developed using the same methodology that was used for the conservative source terms in this study. A separate consequence analysis was performed and compared against the results for the SR6H-C analysis. As shown in Figure 10-5, the effect of moving the accident initiation time from 34 hours to 20 hours has a very small effect on the early fatality risk curve when no evacuation is assumed. Hence, the spread of initiation times that is possible is reasonably represented by the two-point approach of realistic and conservative release times used for all release categories analyzed in this study. The sensitivity analysis shows that the results would not change appreciably even if more conservative accident initiation times are assumed.

10.2 Consequences for Shutdown Events

Upon review of the final results for source terms and accident frequencies, it was determined that the type 1 releases (SR1D, SR1P, SR1H) did not have to be analyzed further because of their low frequencies and smaller source terms compared to the corresponding type 6 releases. In addition, it had been determined in PLG-0465 (Reference 3) that intact containment releases, exemplified here as the type "D" releases, (S3W in PLG-0465) made negligible contributions to risk of early health effects and to the dose versus distance curves. Hence, CRACIT runs using the same methodology as PLG-0465 were run for all releases with containment leakage categories "P" and "H" and RCS conditions "2" and "6" for a total of four release categories: SR2P, SR2H, SR6P, SR6H. For each release category, a total of 4 runs were made to cover a conservative and realistic source term and to account for both no evacuation and 2 mile evacuation cases. The runs that were made and the key to finding plots of the results for separate runs is provided in Table 10-11.

As shown in this table, only one of the 2 mile evacuation cases (SR2H), simulated any early fatalities within the area for the safety goal evaluation (1.5 miles from the plant, corresponding to 1 mile from the site boundary). The greatest numbers of early fatalities within 1.5 miles are observed with release categories R6P and R2H for cases with conservative source terms and no evacuation. This is true despite the fact that case SR6H-C has the greatest release fractions. The reason for this is that SR6H has a much higher energy release rate and the enhanced plume rise reduces the doses close to the site. On the other hand, SR6H-C does produce the greatest level of consequences when the zone outside the safety goal region is included. Hence, the results for SR6H exhibit the same behavior as determined in PLG-0465 for Category S1W.

It is important to note that when realistic source terms and a 2-mile evacuation are assumed, there are no early fatalities observed whatsoever. Even when no evacuation is assumed with realistic source terms, only fractional results for early fatalities are observed. Fractional results indicate that thresholds for prompt radiation deaths are only realized for a fraction of the meteorological scenarios that were analyzed in CRACIT. Hence, nearly all the risk calculated in this study is the result of the conservative source term cases. In fact, none of the risk in the 2-mile evacuation cases is due to cases with realistic source terms.

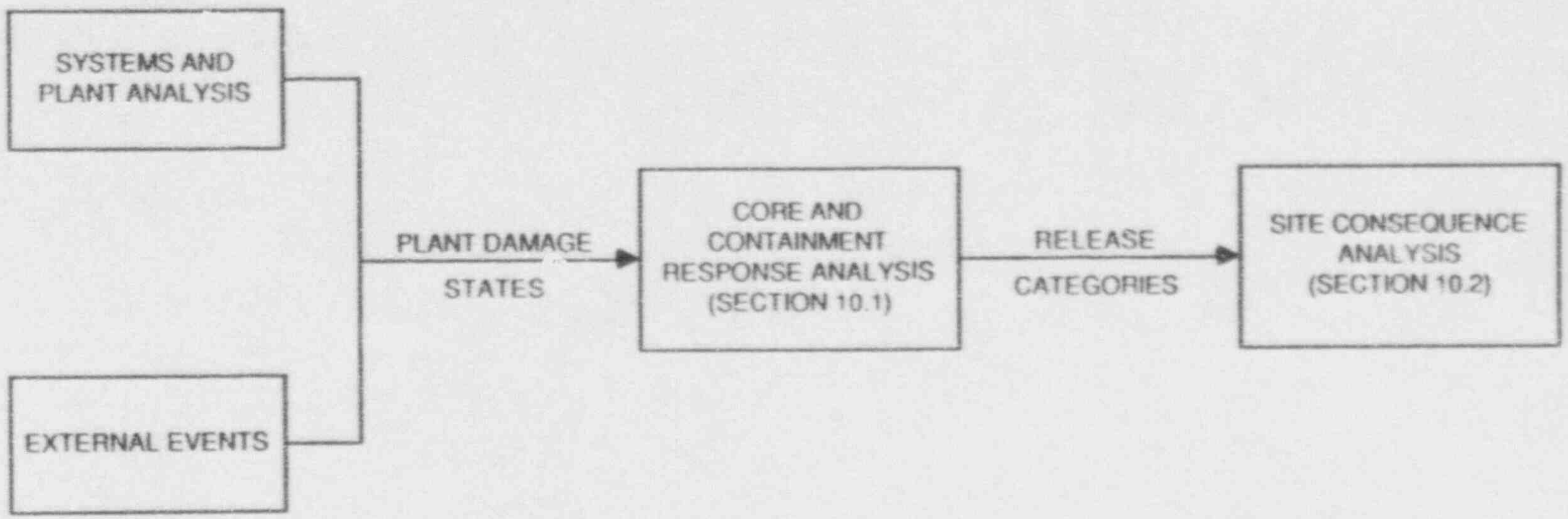


FIGURE 10-1
CORE AND CONTAINMENT
RESPONSE ANALYSIS INTERFACES

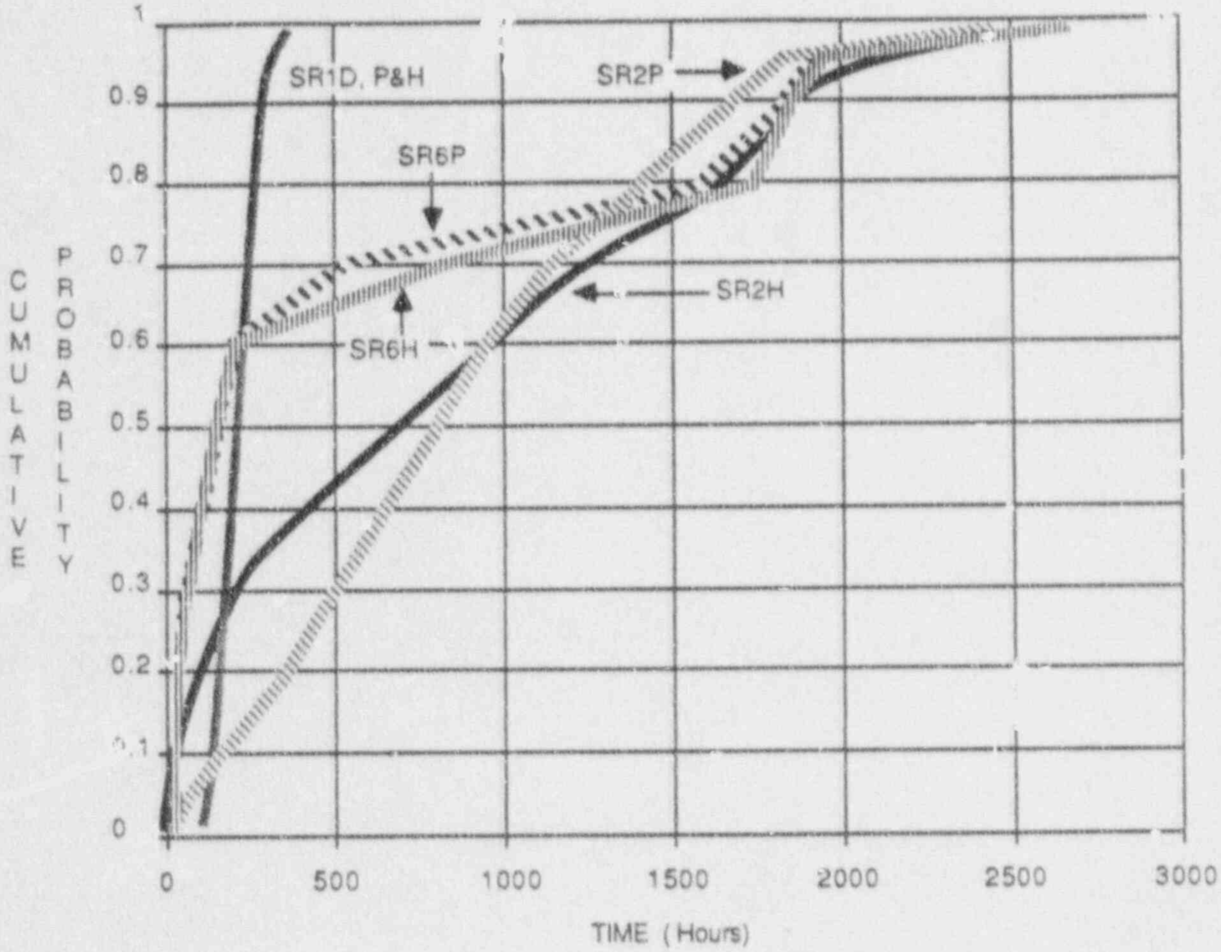


FIGURE 10-2

CUMULATIVE ACCIDENT INITIATION TIME DISTRIBUTION FOR EACH RELEASE CATEGORY

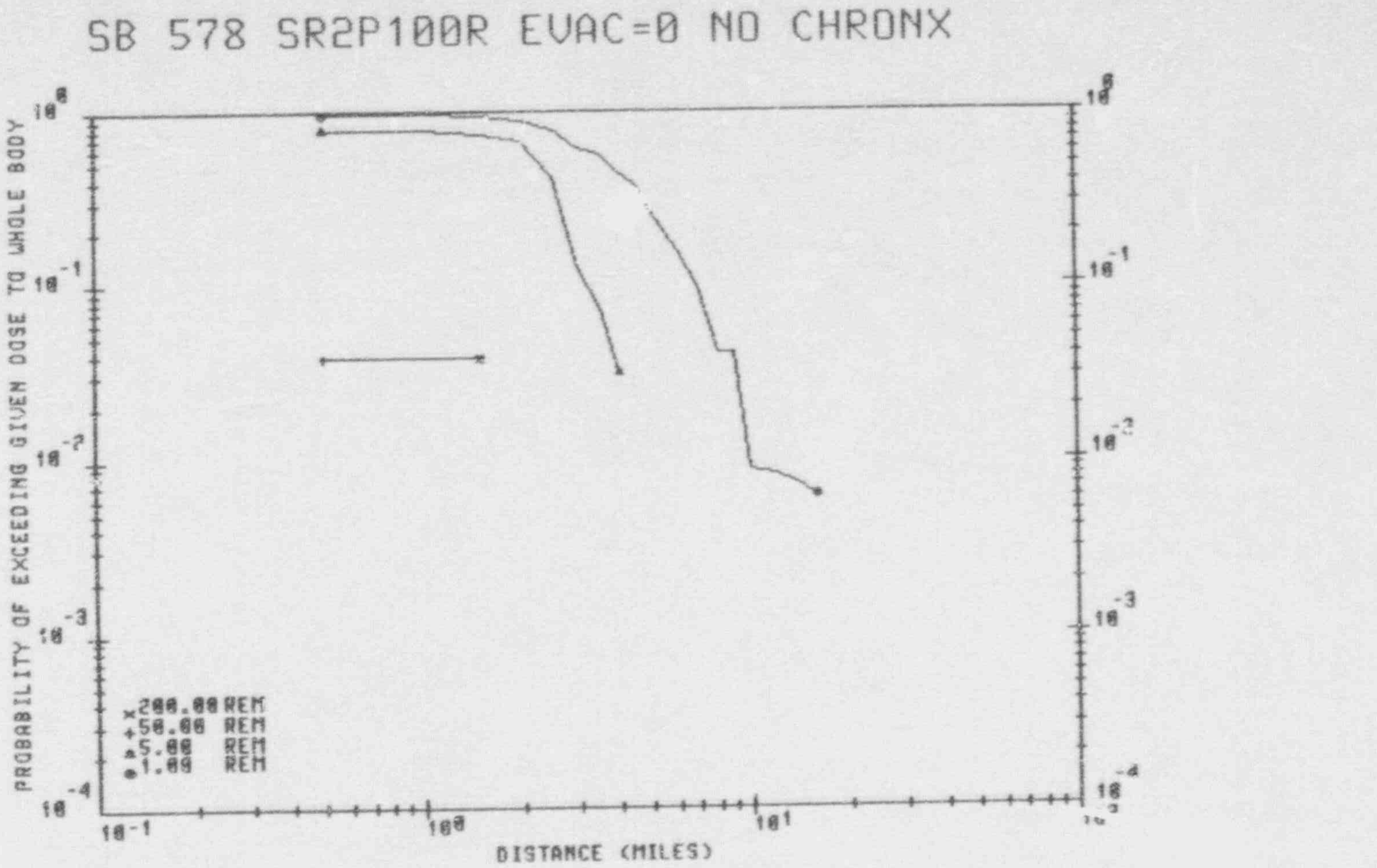


FIGURE 10-3a. CONDITIONAL FREQUENCY OF DOSE AS A FUNCTION OF DISTANCE
FOR RELEASE CATEGORY SR2P-100R
FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 578)

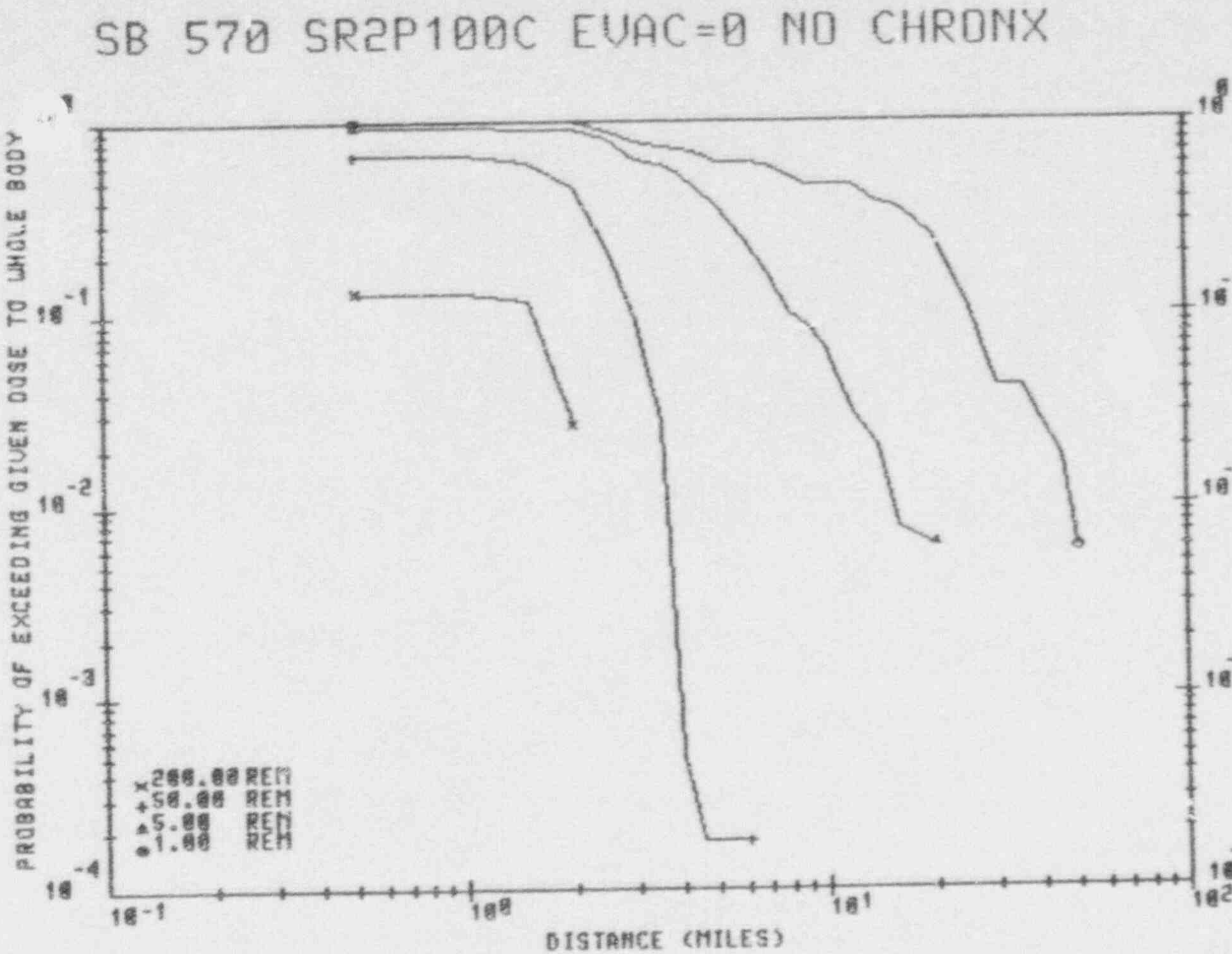


FIGURE 10-3b. CONDITIONAL FREQUENCY OF DOSE AS A FUNCTION OF DISTANCE FOR RELEASE CATEGORY SR2P-100C FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 570)

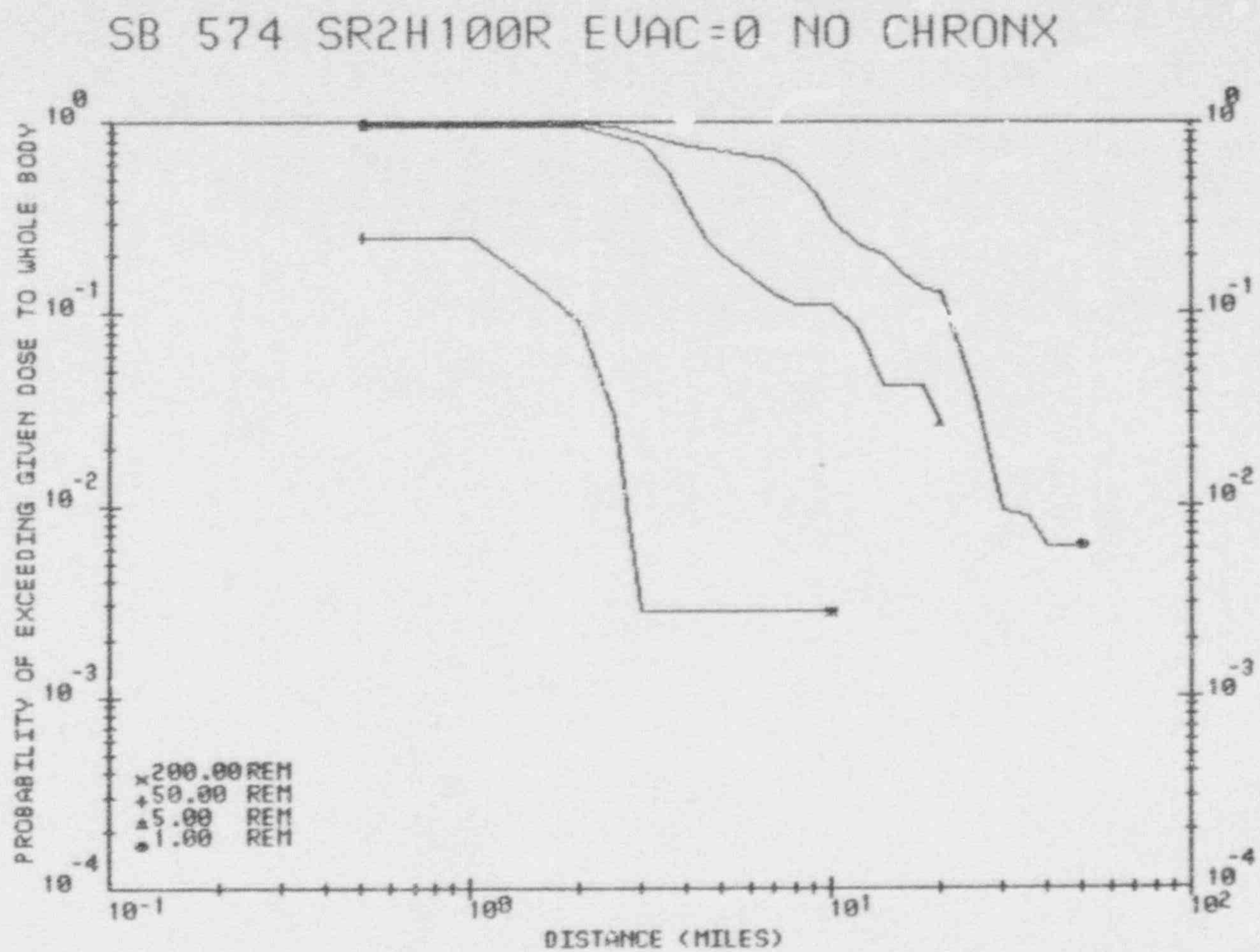


FIGURE 10-3c. CONDITIONAL FREQUENCY OF DOSE AS A FUNCTION OF DISTANCE FOR RELEASE CATEGORY SR2H-100R FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 574)

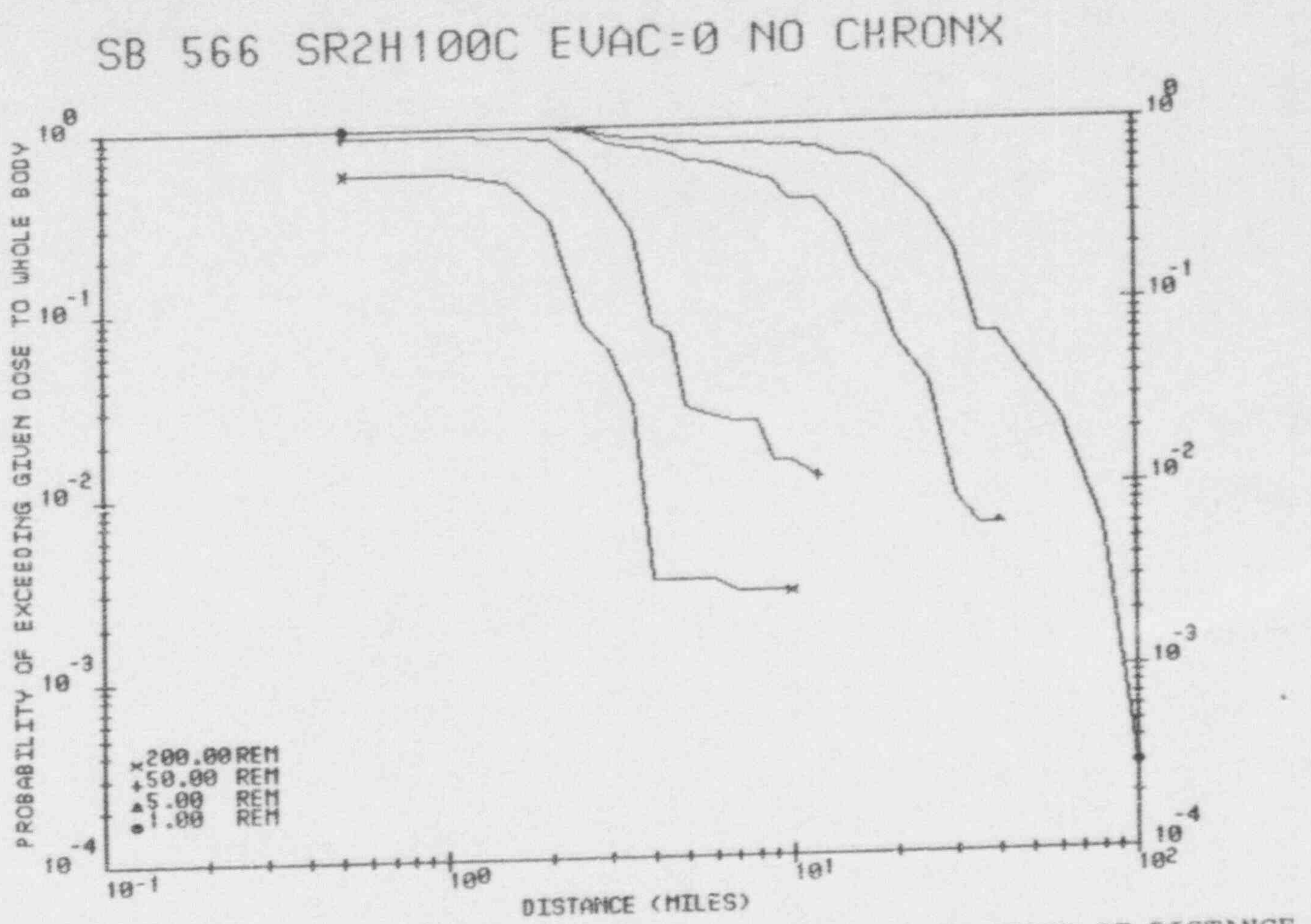


FIGURE 10-3d. CONDITIONAL FREQUENCY OF DOSE AS A FUNCTION OF DISTANCE FOR RELEASE CATEGORY SR2H-100C FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 566)

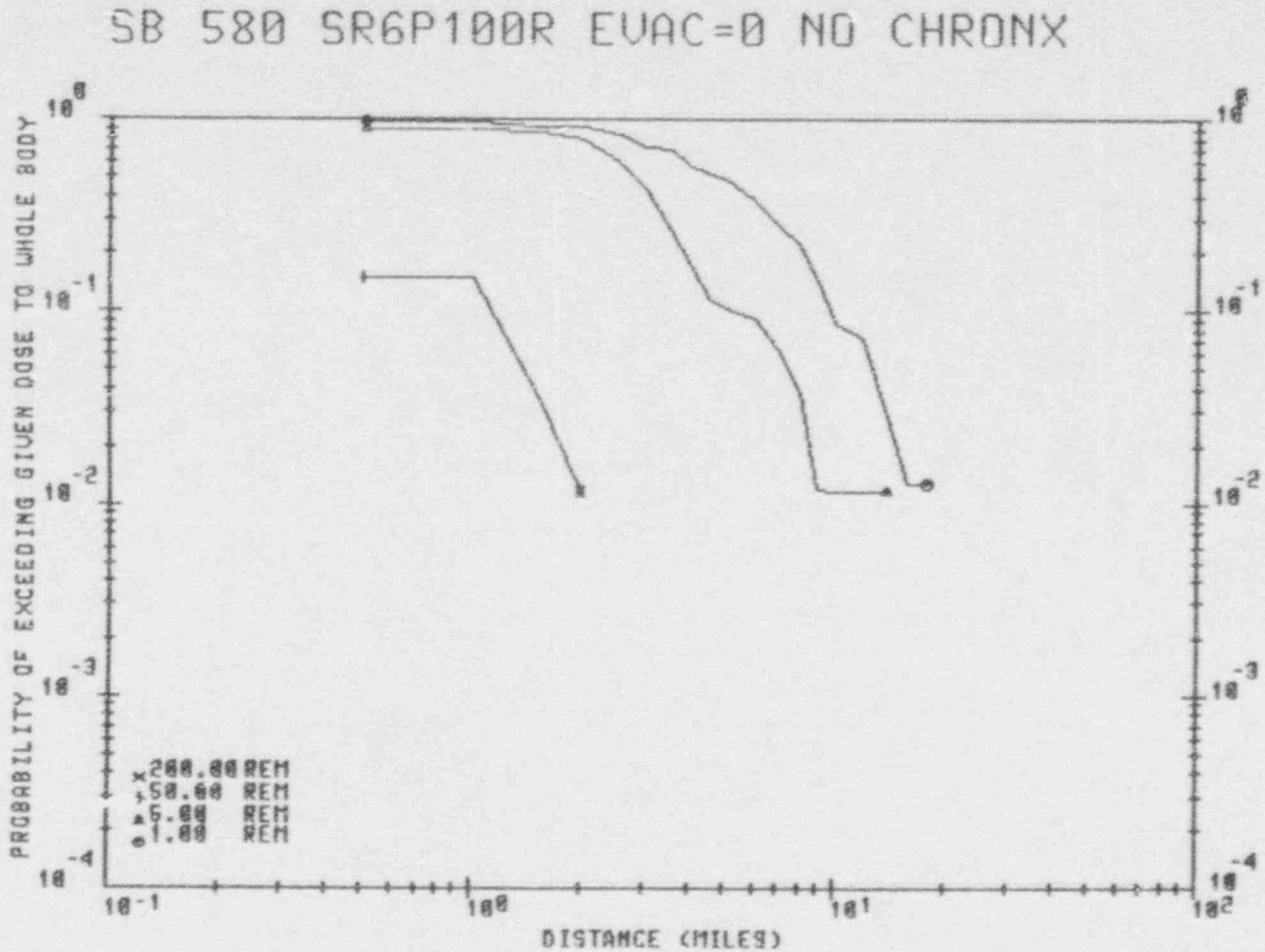


FIGURE 10-3e. CONDITIONAL FREQUENCY OF DOSE AS A FUNCTION OF DISTANCE FOR RELEASE CATEGORY SR6P-100R FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 580)

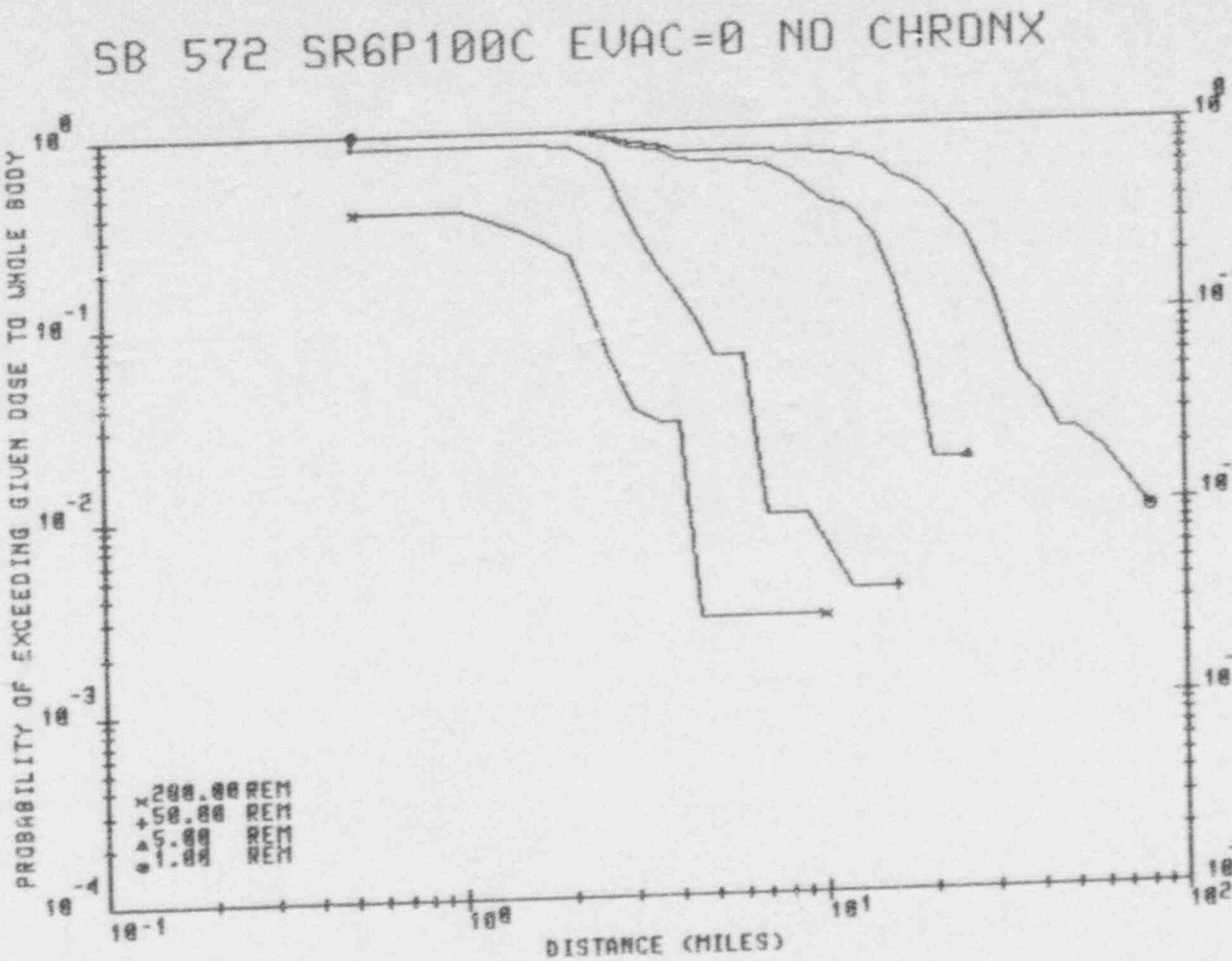


FIGURE 10-3f. CONDITIONAL FREQUENCY OF DOSE AS A FUNCTION OF DISTANCE FOR RELEASE CATEGORY SR6P-100C FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 572)

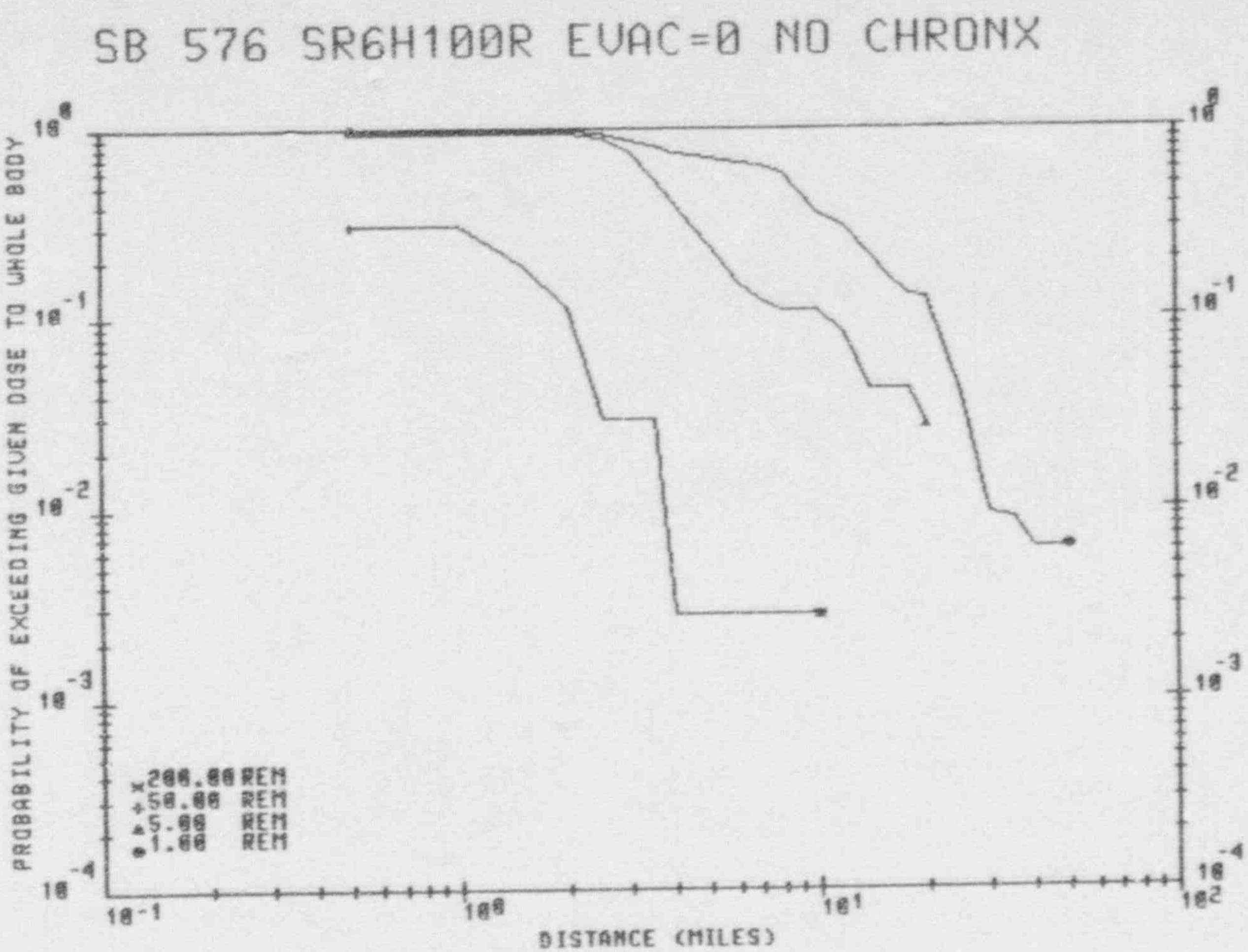


FIGURE 10-3g. CONDITIONAL FREQUENCY OF DOSE AS A FUNCTION OF DISTANCE FOR RELEASE CATEGORY SR6H-100R FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 576)

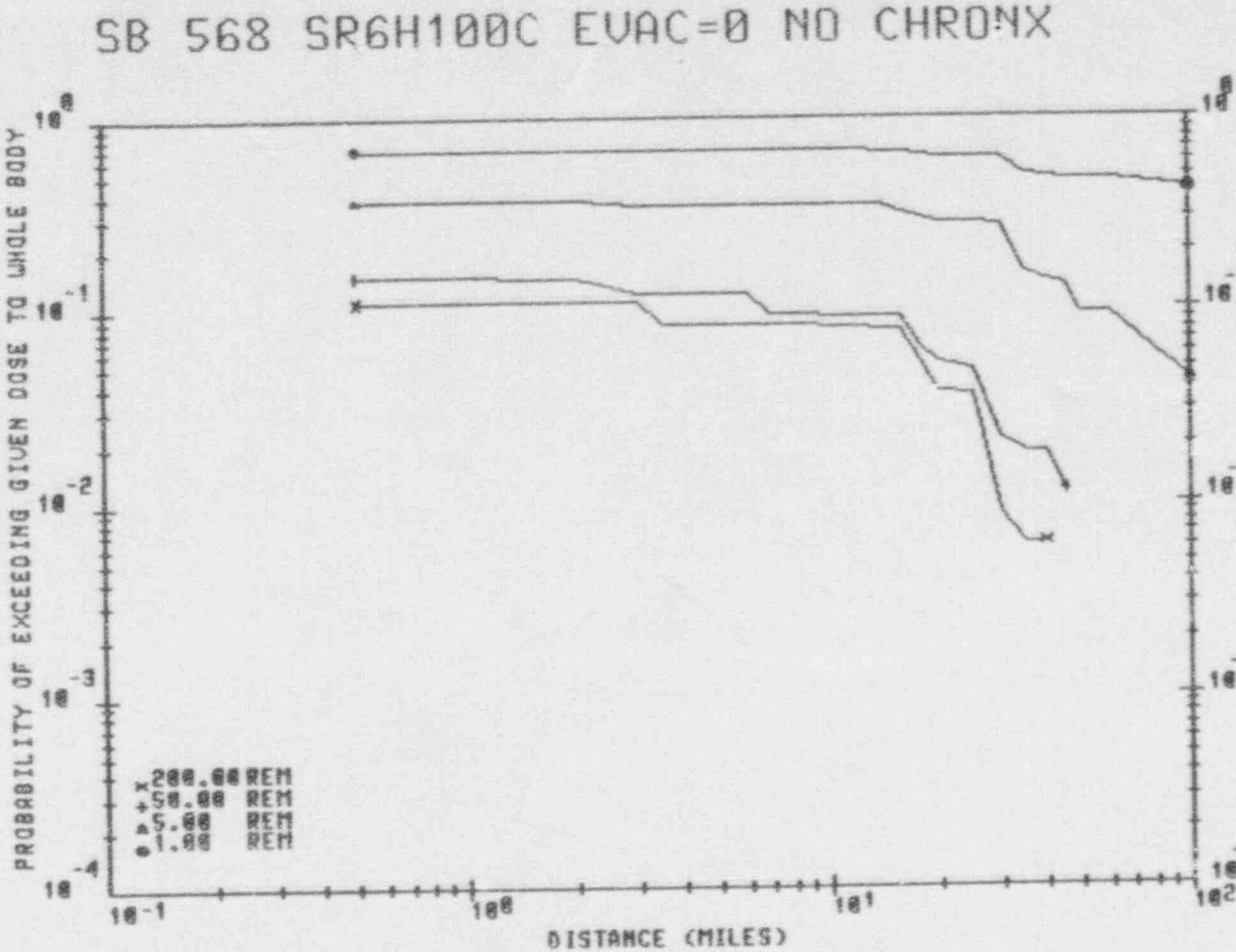


FIGURE 10-3h. CONDITIONAL FREQUENCY OF DOSE AS A FUNCTION OF DISTANCE FOR RELEASE CATEGORY SR6H-100C FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 568)

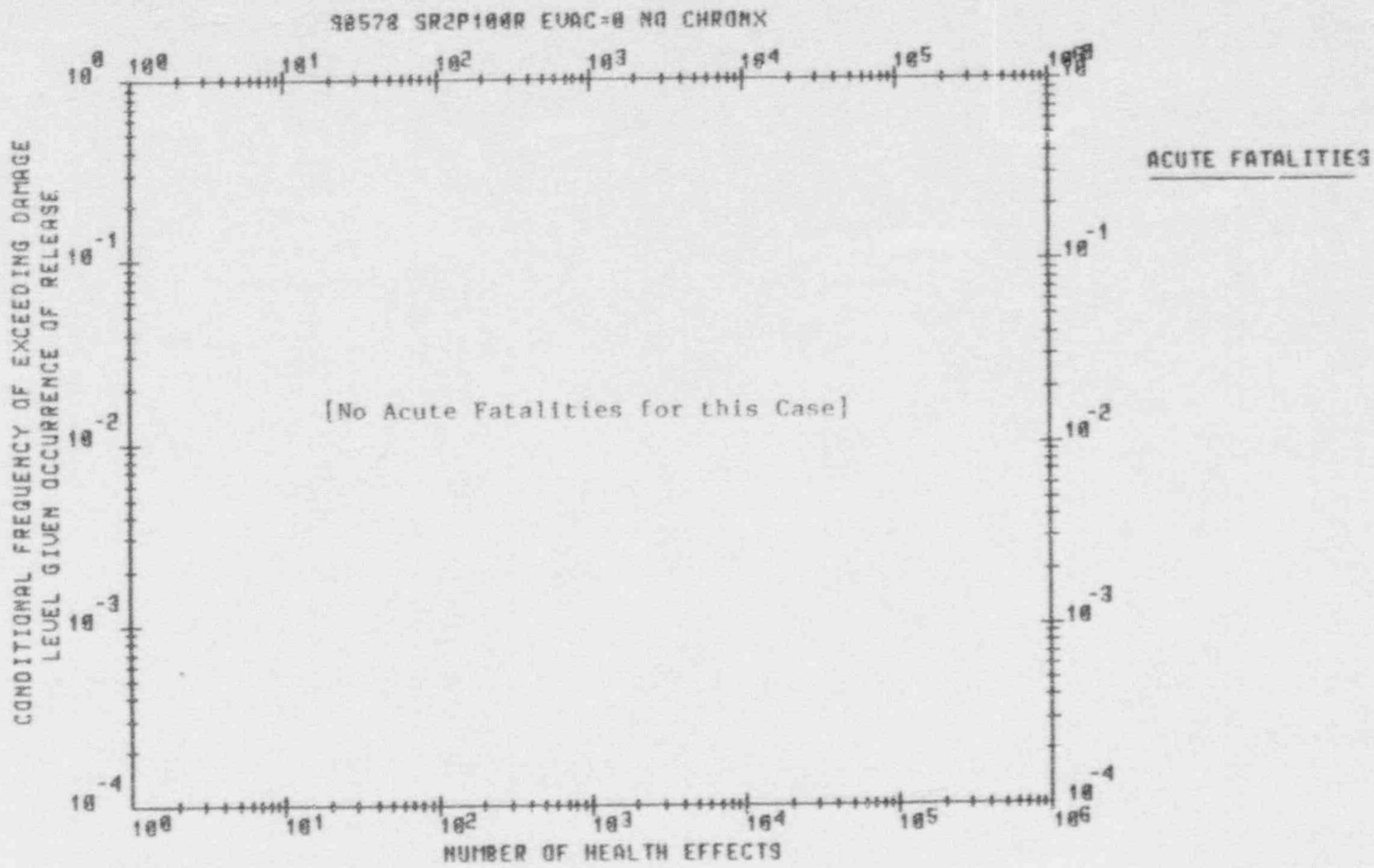


FIGURE 10-4a. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR2P-100R FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 578)

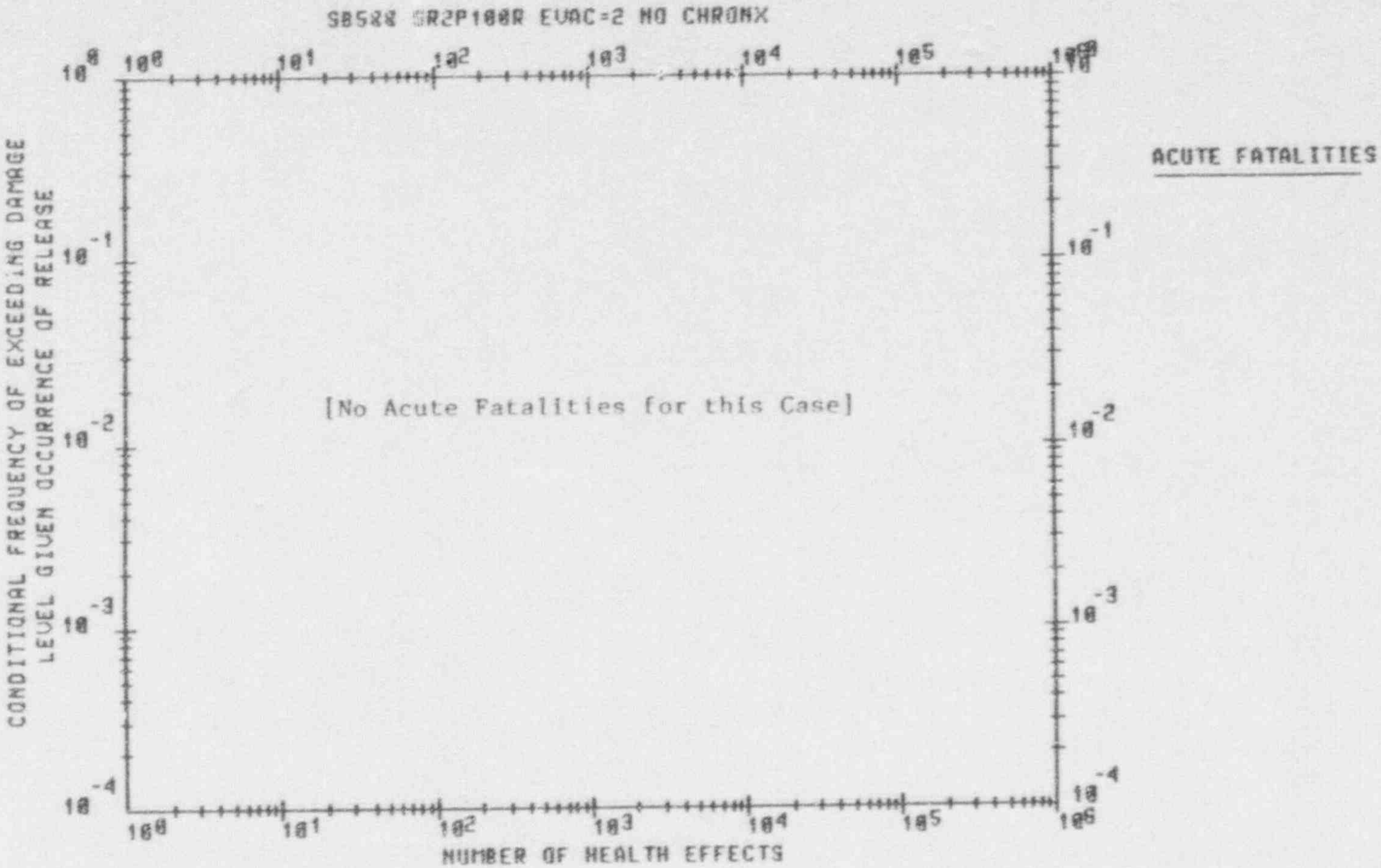


FIGURE 10-4b. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGCRY SR2P-100R FOR 2-MILE EVACUATION (RUN NUMBER 588)

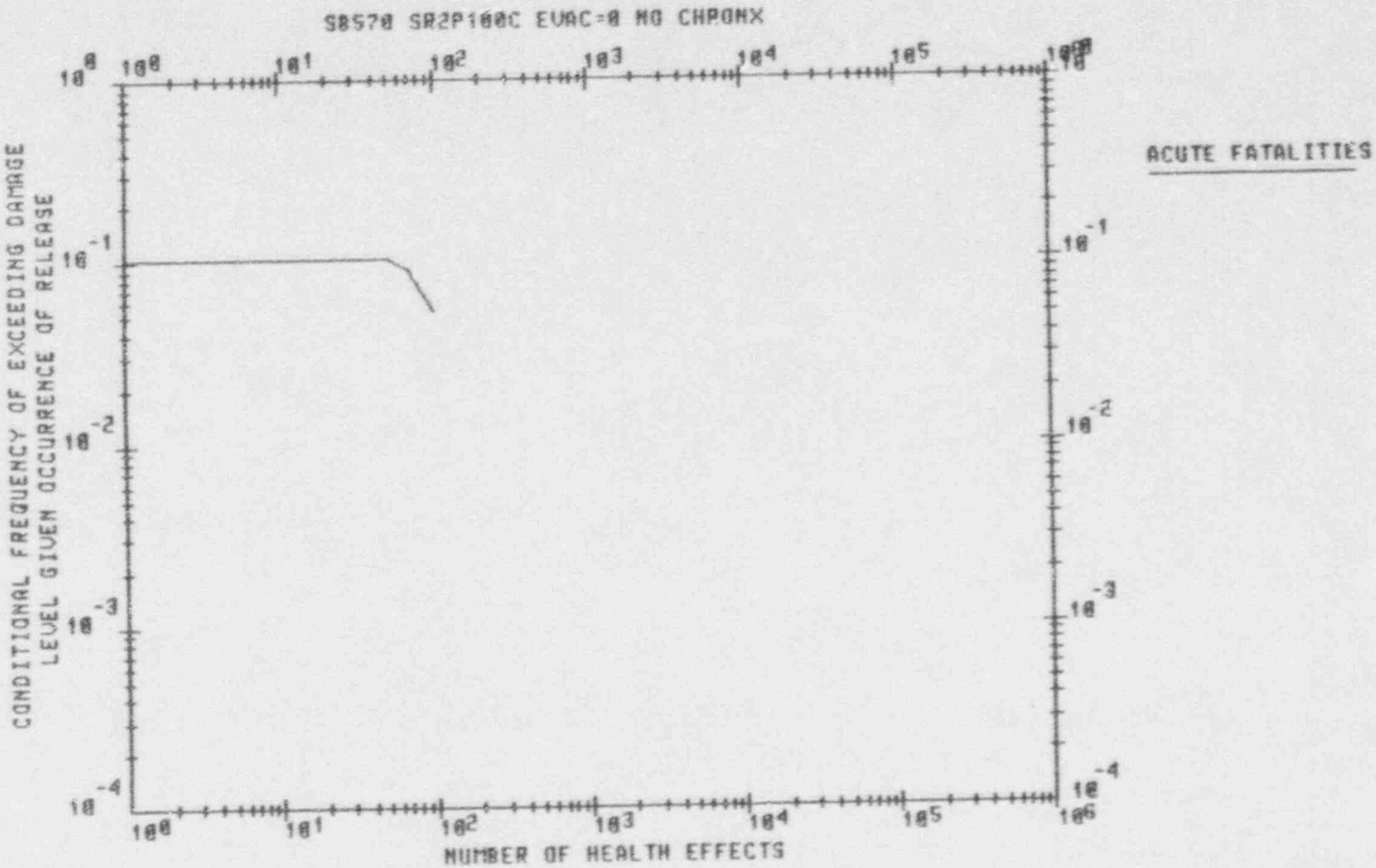


FIGURE 10-4c. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR2P-100C FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 570)

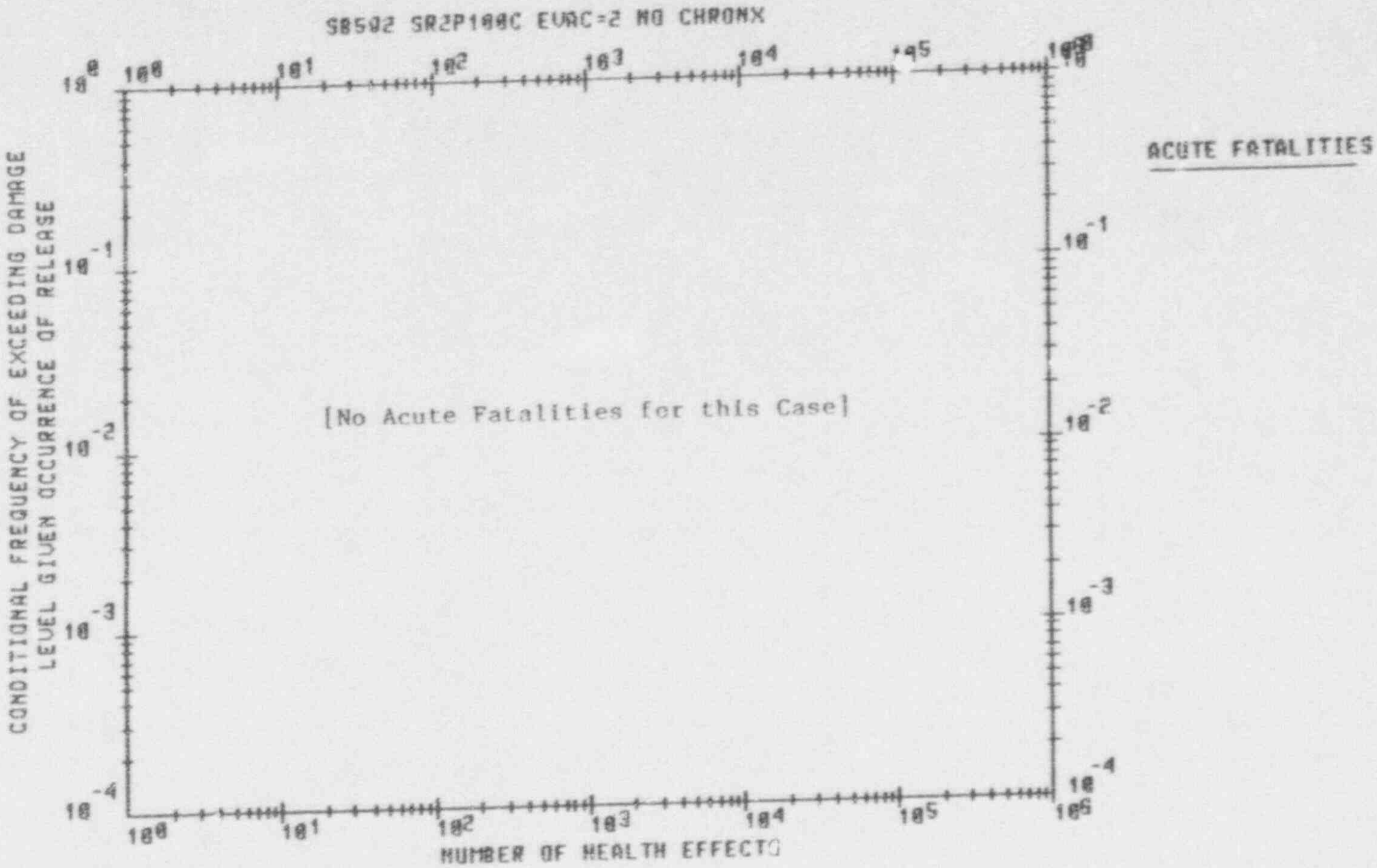


FIGURE 10-4d. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR2P-100C FOR 2-MILE EVACUATION (RUN NUMBER 592)

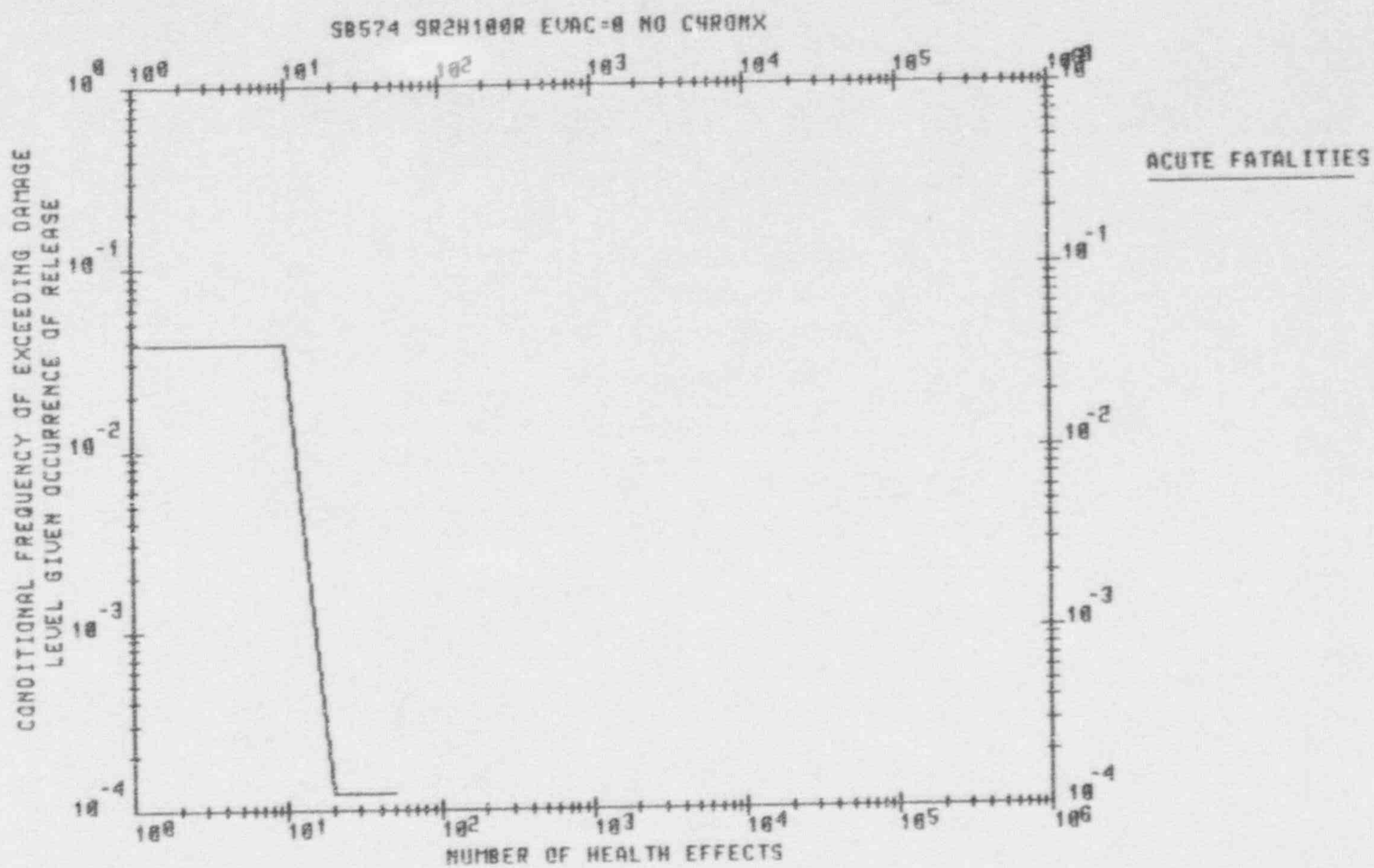


FIGURE 10-4e. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR2H-100R FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 574)

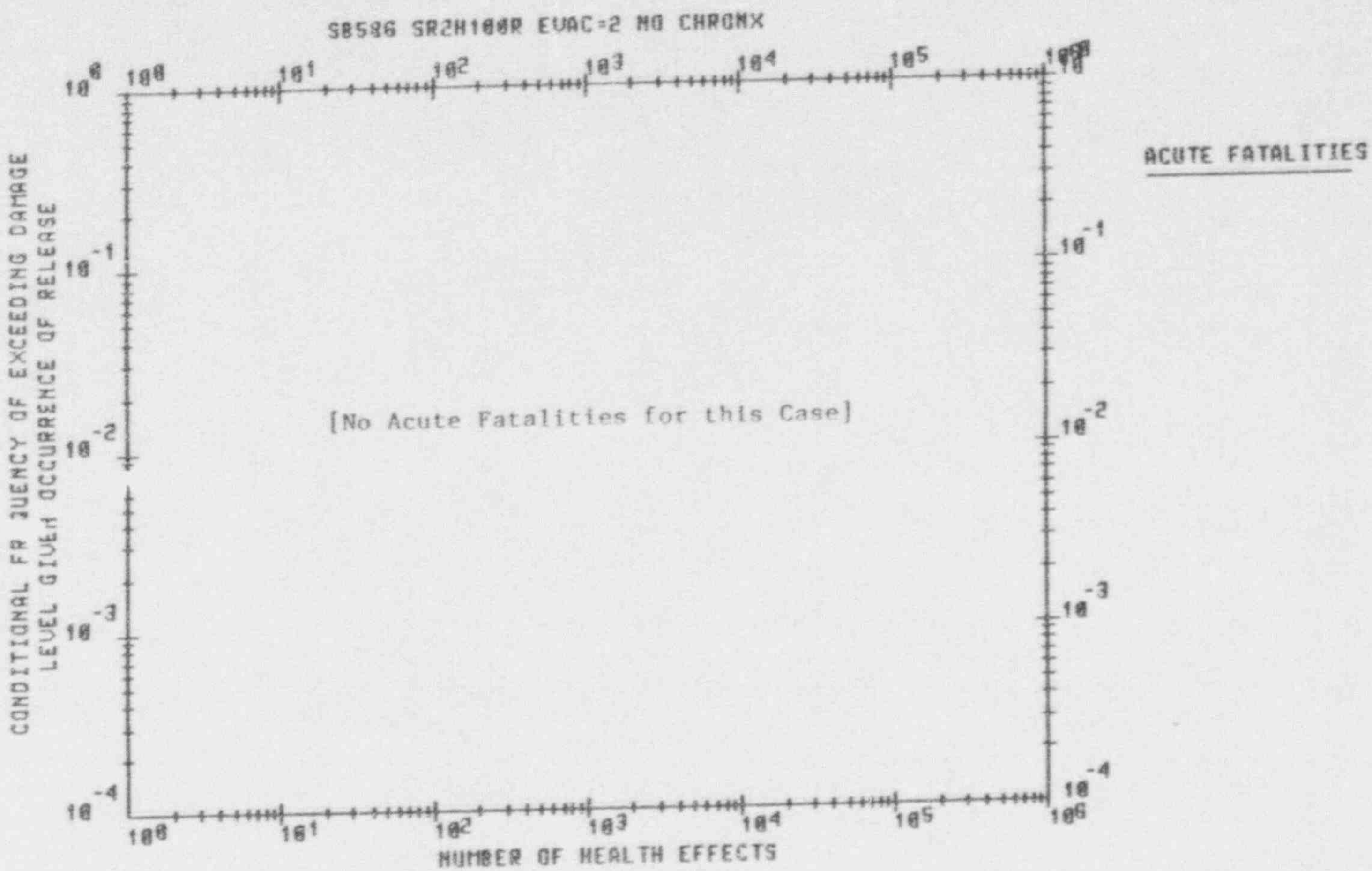


FIGURE 10-4f. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR2H-100R FOR 2-MILE EVACUATION (RUN NUMBER 586)

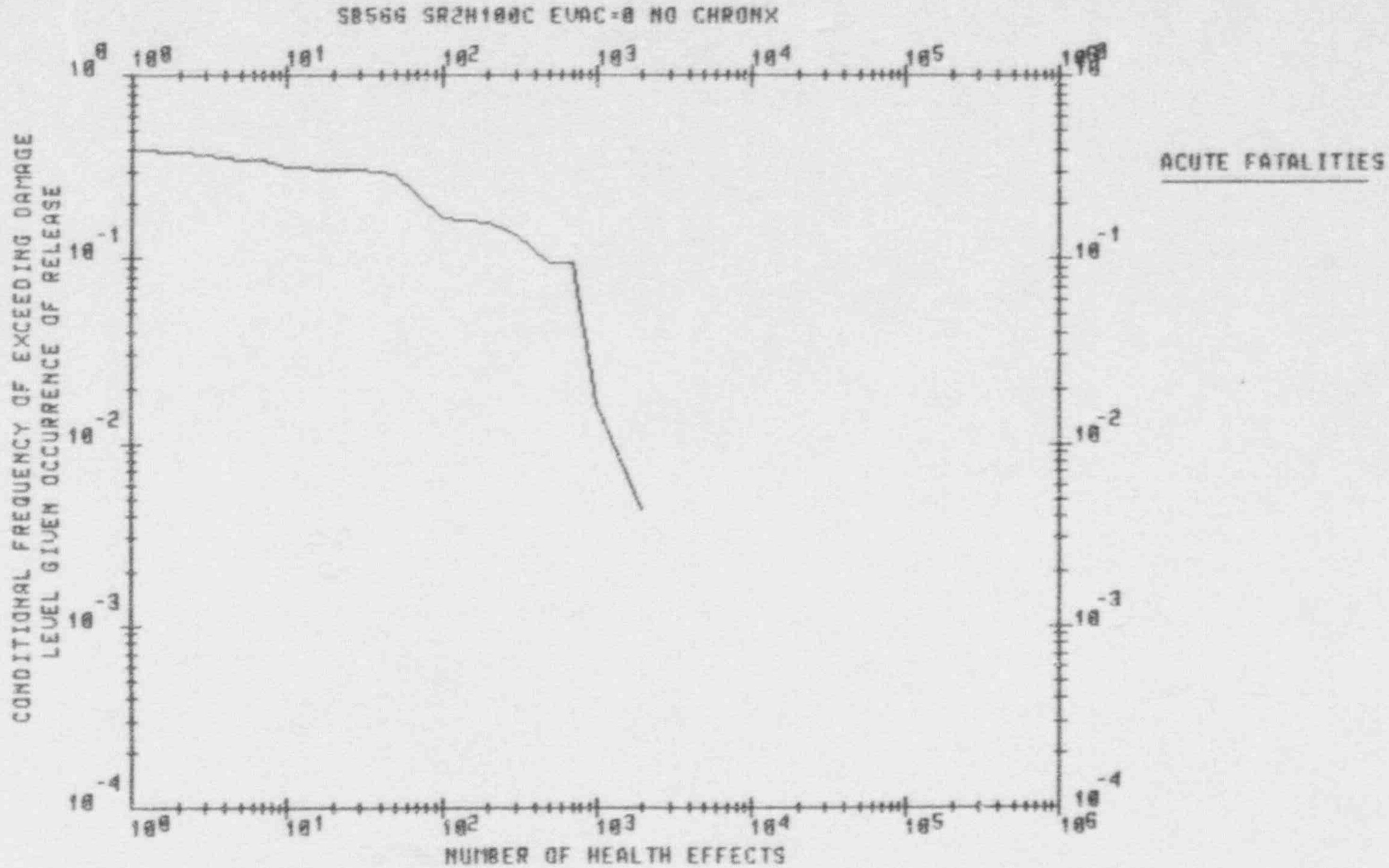


FIGURE 10-4g. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR2H-100C FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 566)

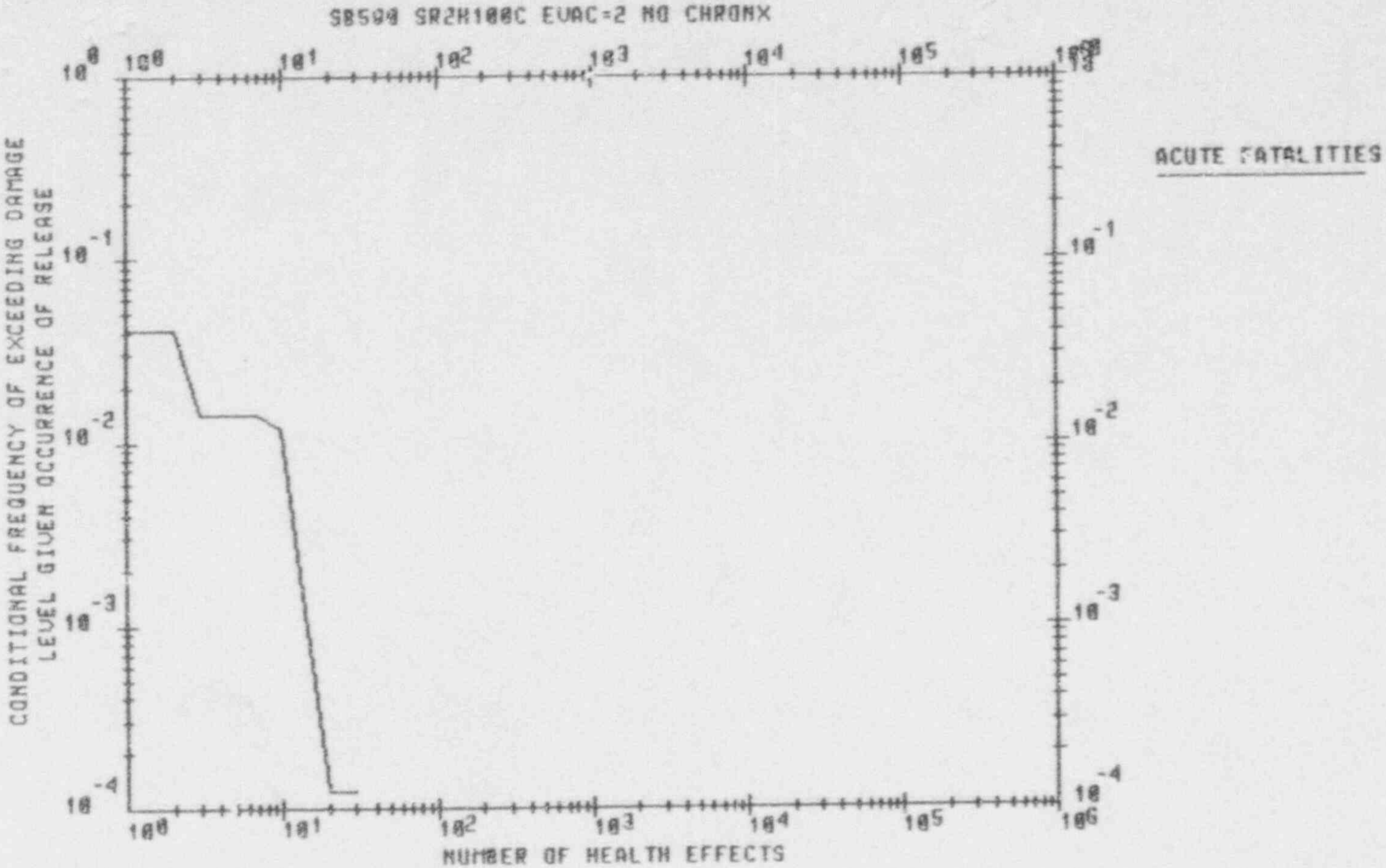


FIGURE 10-4h. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR2H-100C FOR 2-MILE EVACUATION (RUN NUMBER 590)

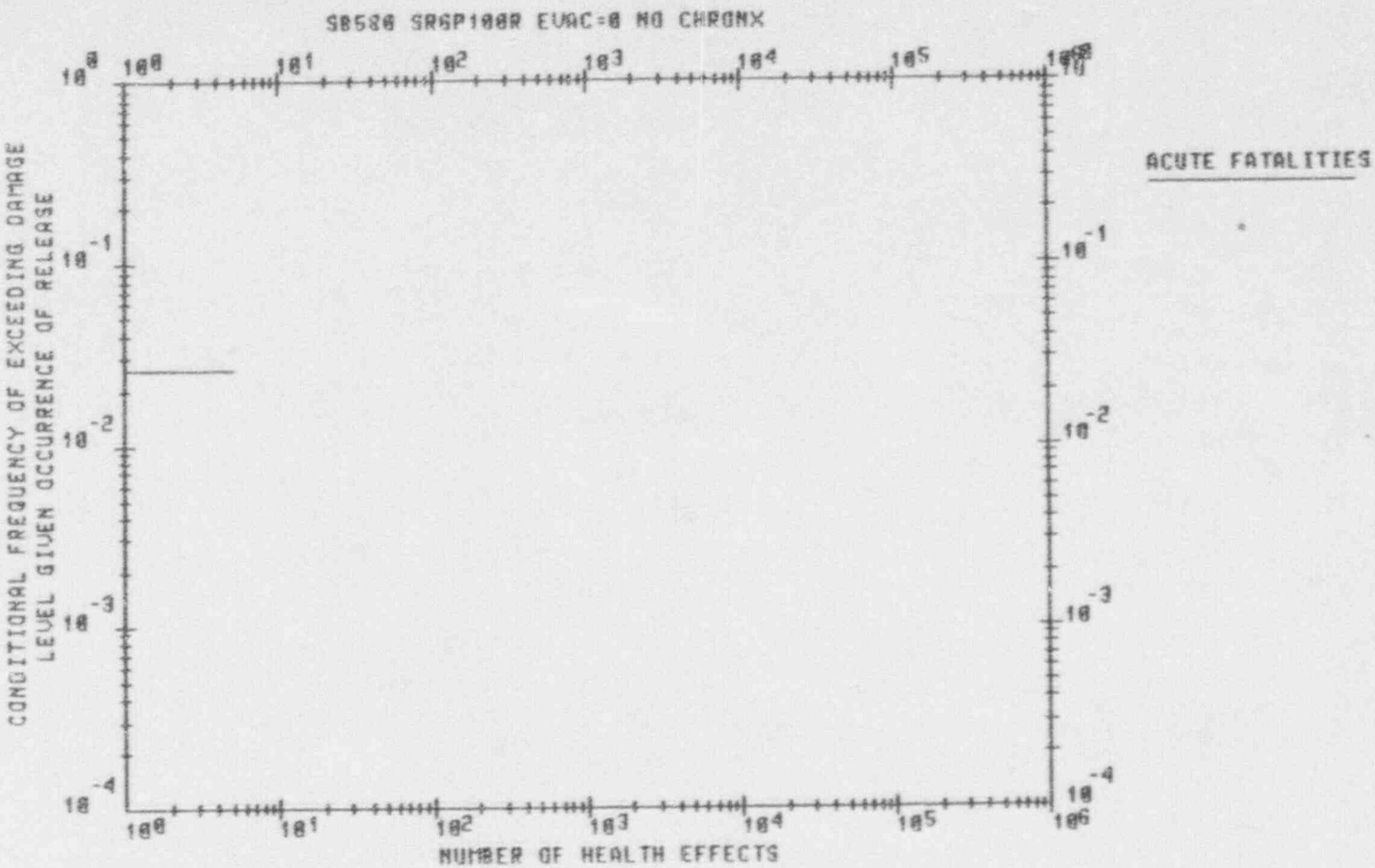


FIGURE 10-4i. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR6P-100R FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 580)

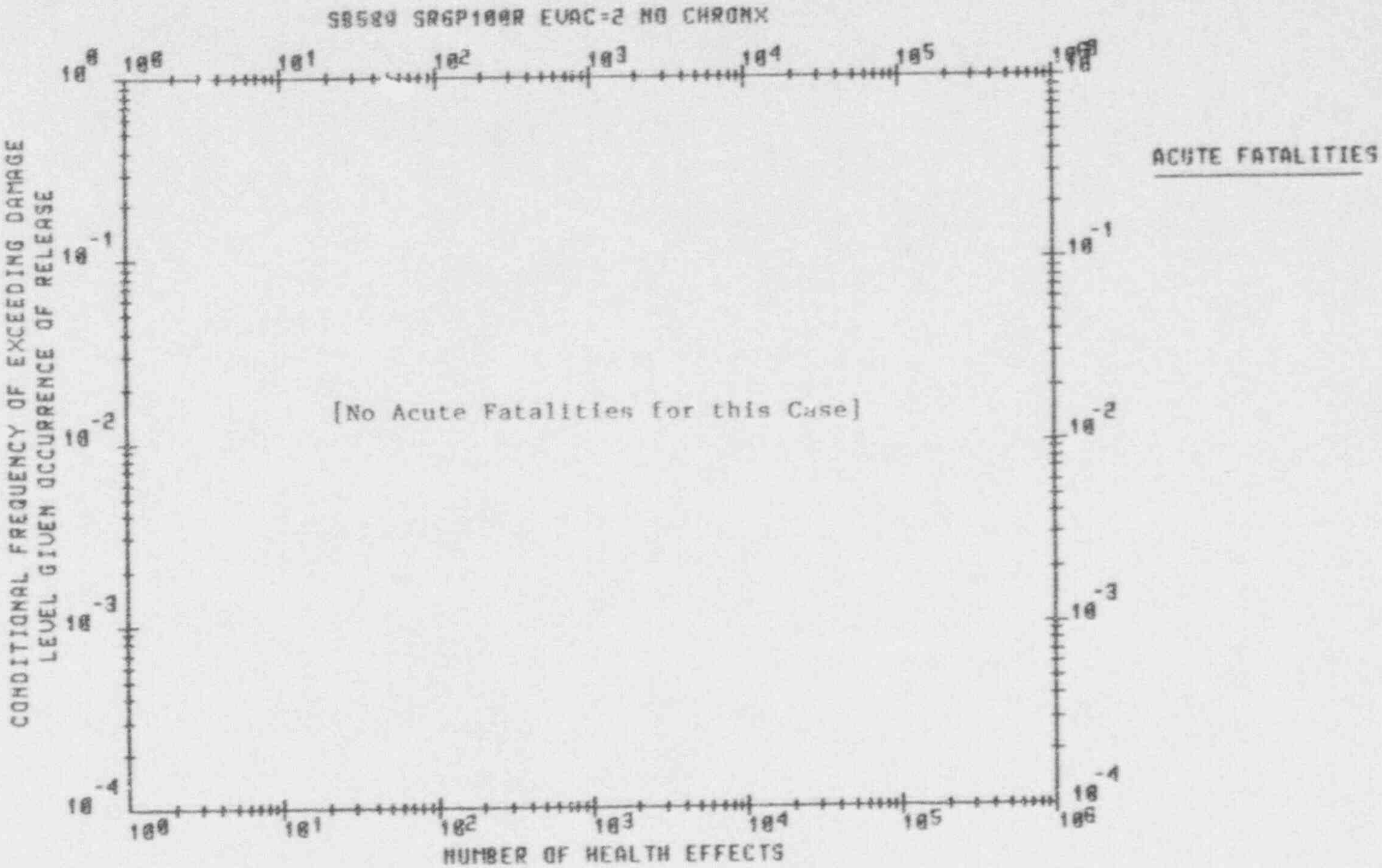


FIGURE 10-4j. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR6P-100R FOR 2-MILE EVACUATION (RUN NUMBER 589)

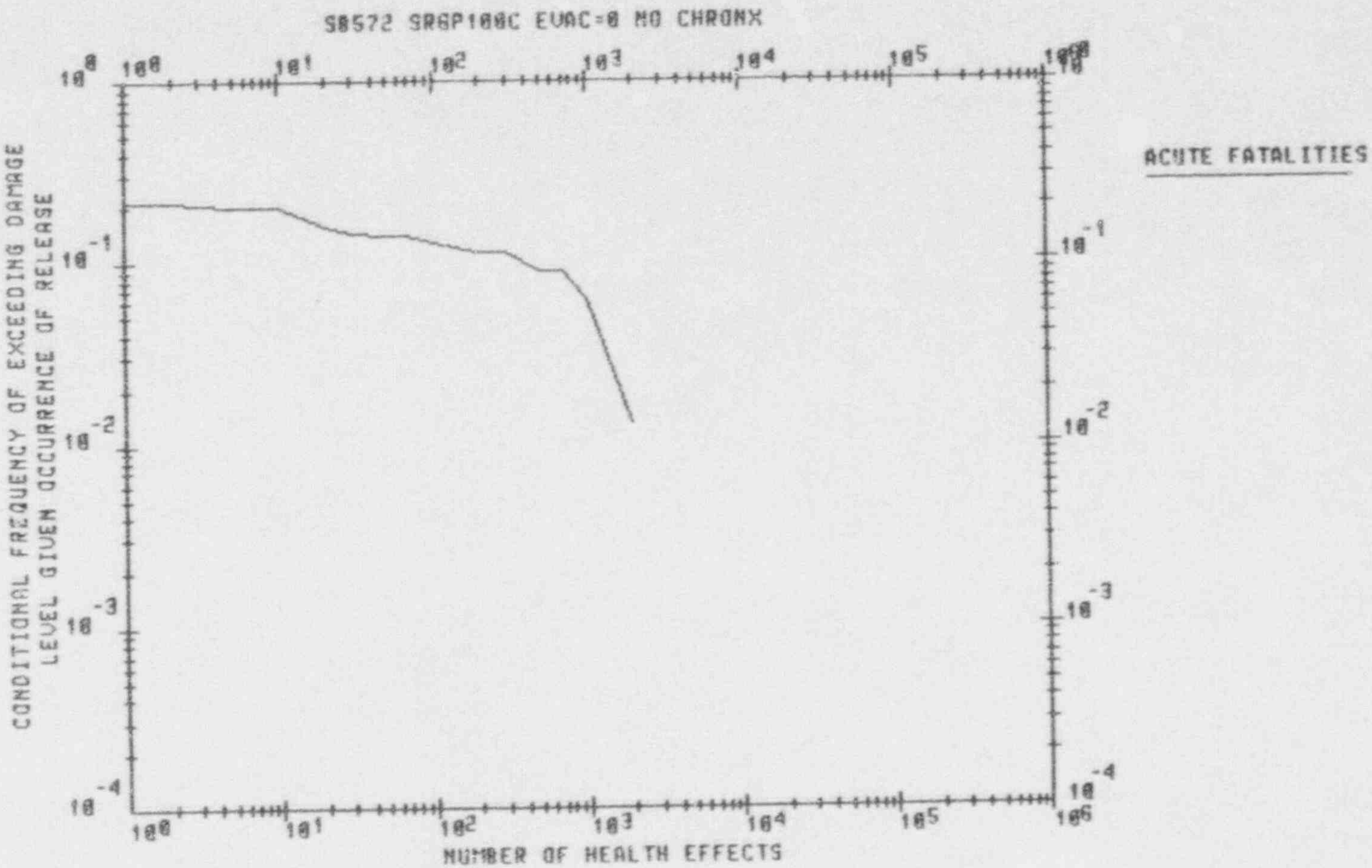


FIGURE 10-4k. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION
FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR6P-100C
FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 572)

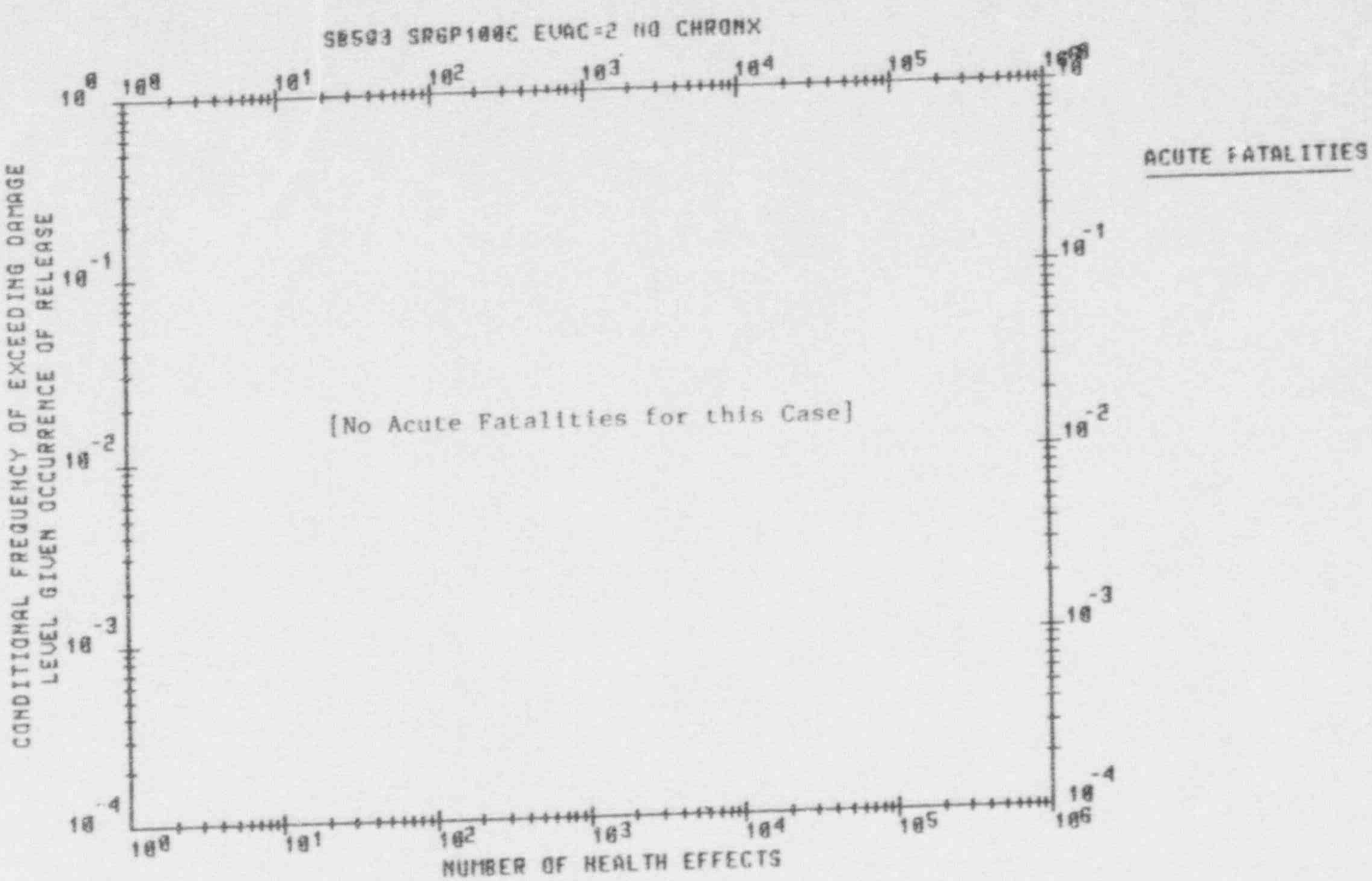


FIGURE 10-41. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR6P-100C FOR 2-MILE EVACUATION (RUN NUMBER 593)

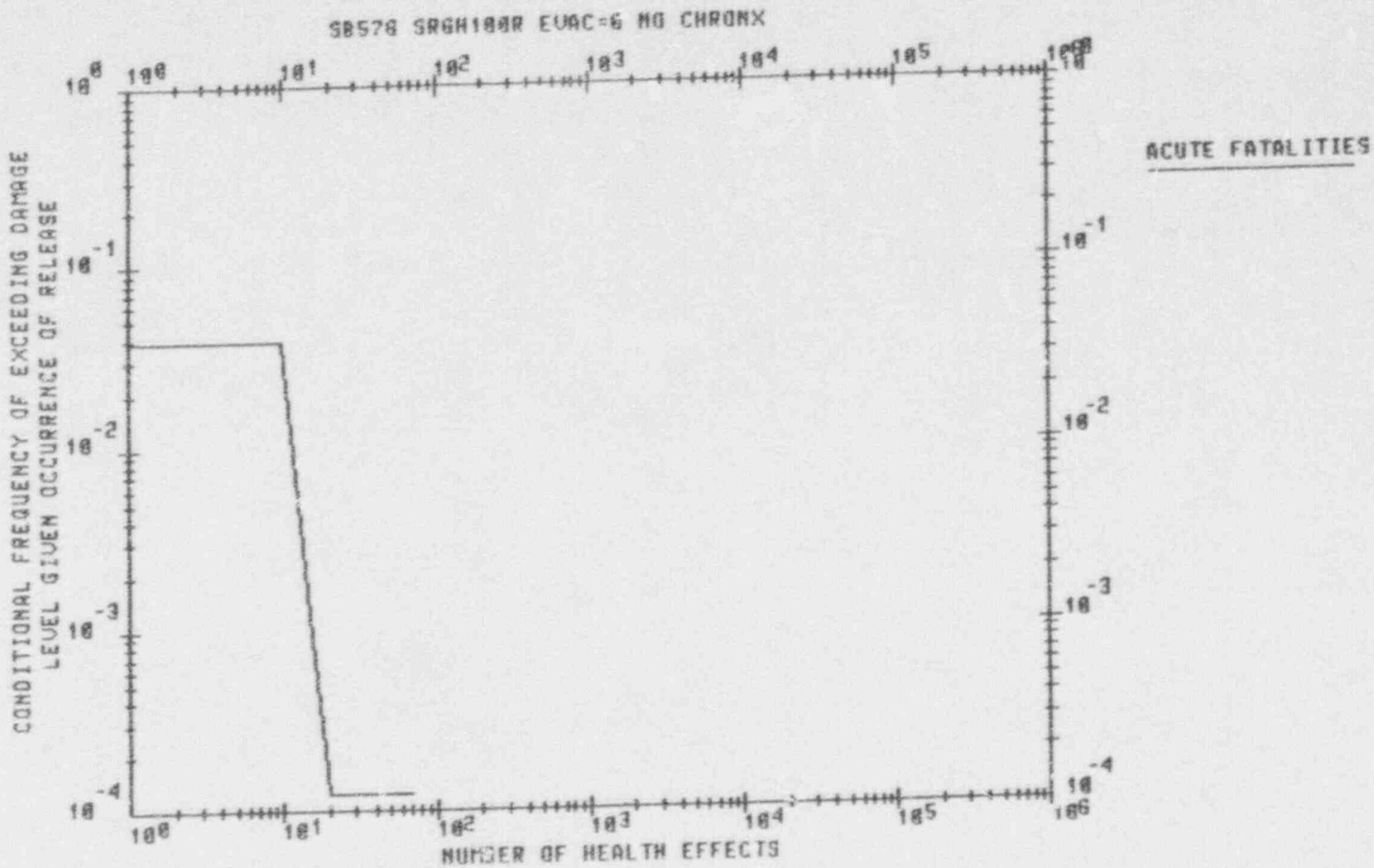


FIGURE 10-4m. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR6H-100R FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 576)

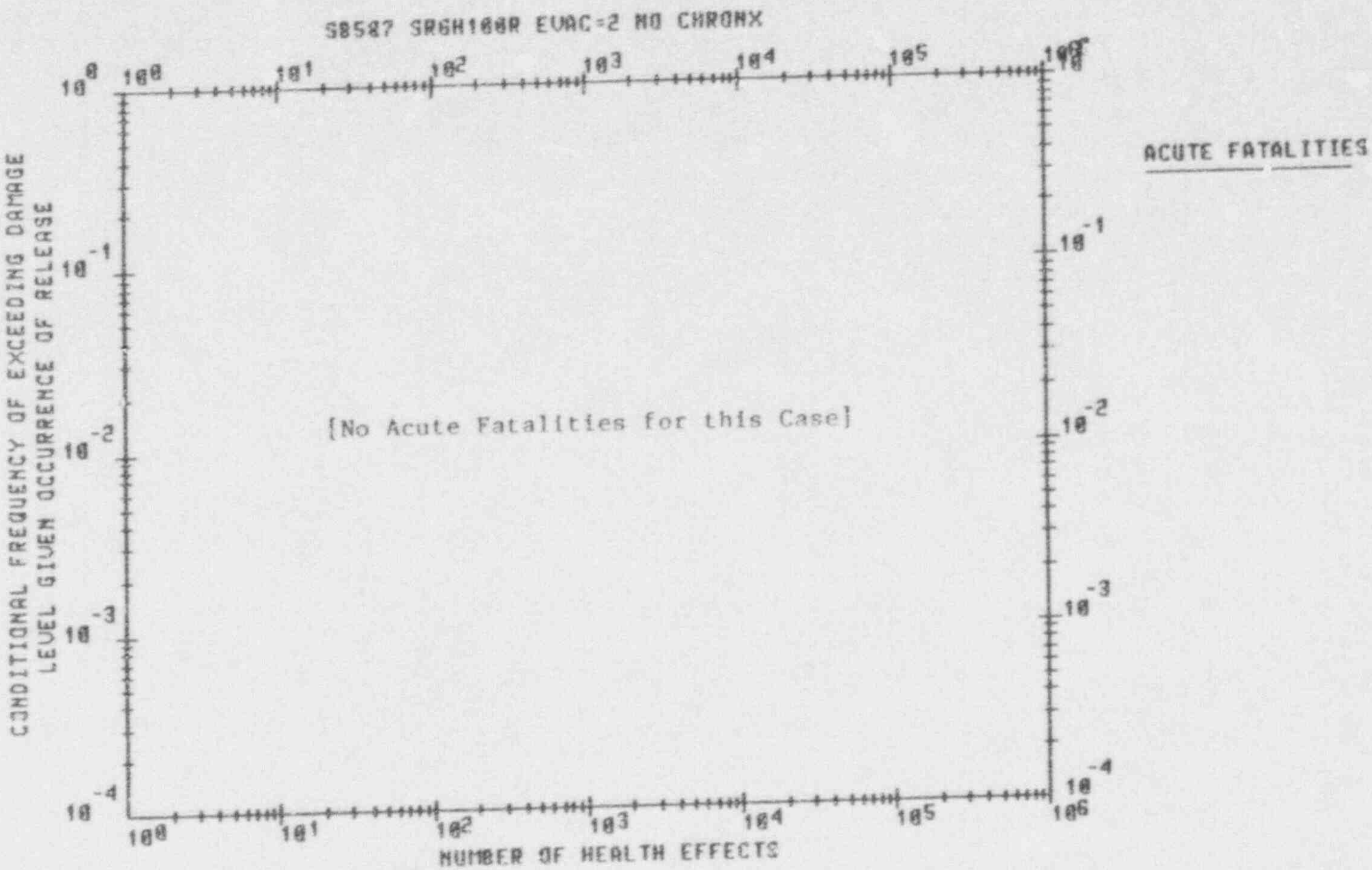


FIGURE 10-4n. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR6H-100R FOR 2-MILE EVACUATION (RUN NUMBER 587)

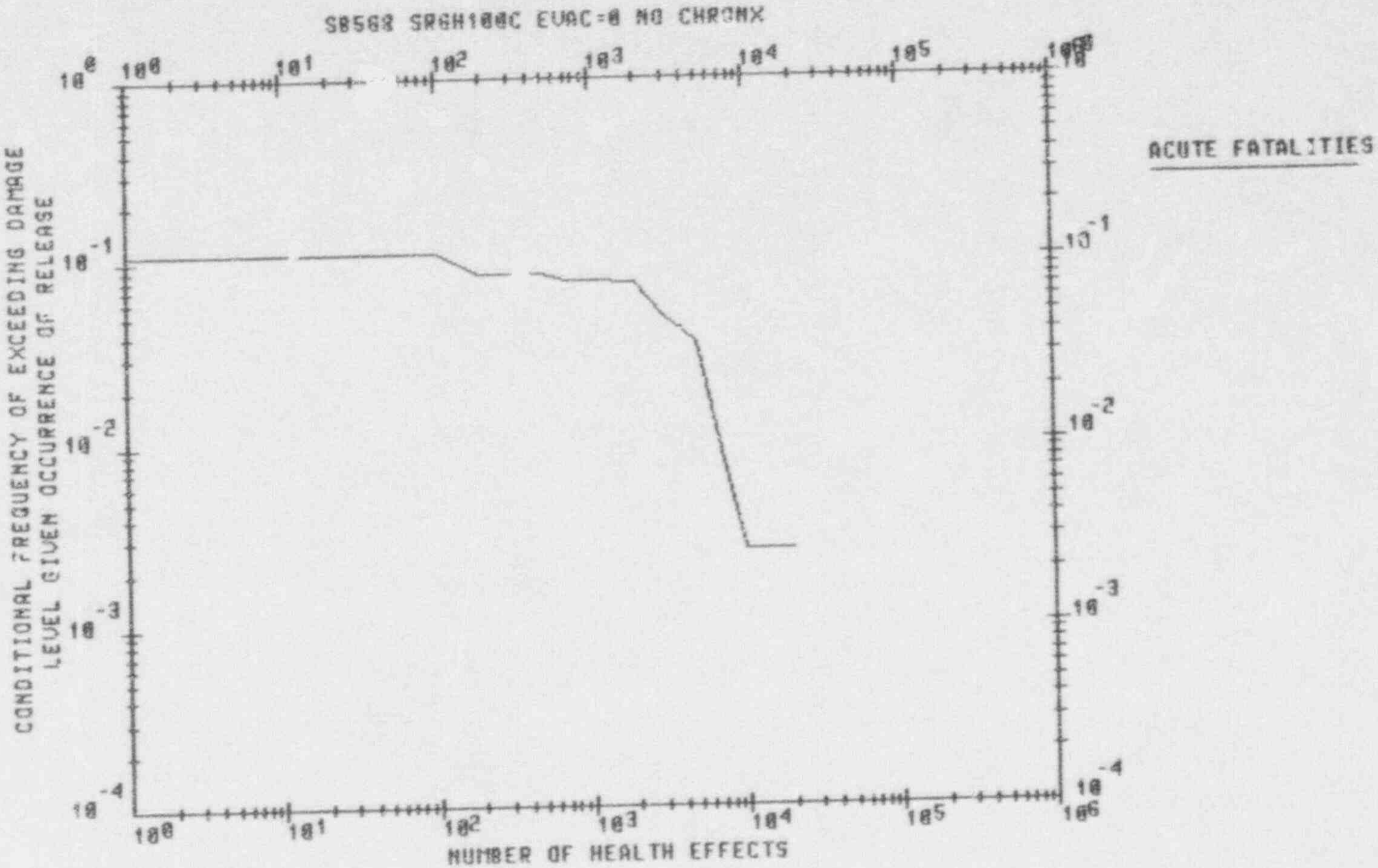


FIGURE 10-4o. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR6H-100C FOR NO IMMEDIATE PROTECTIVE ACTION (RUN NUMBER 568)

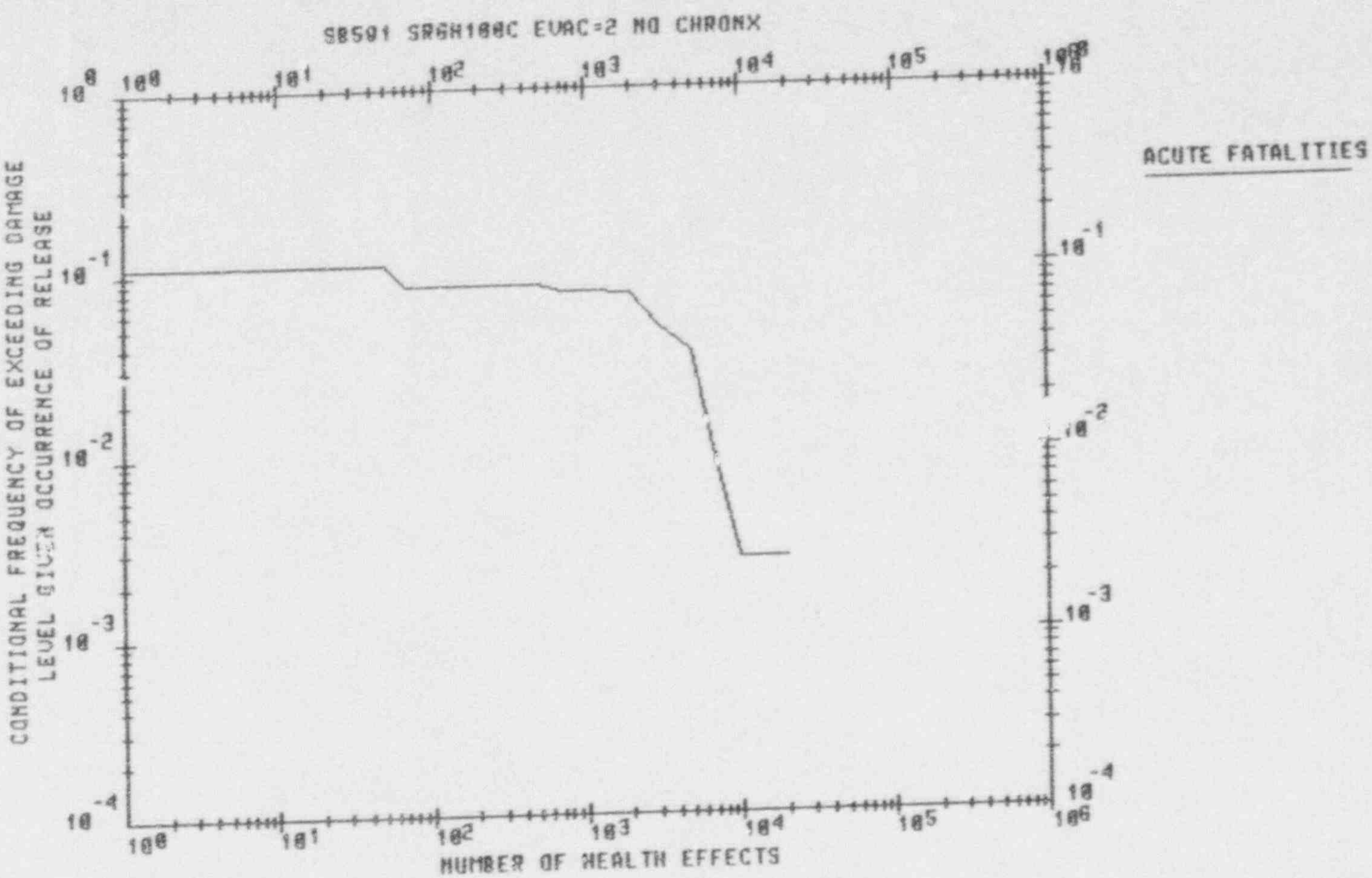


FIGURE 10-4p. COMPLEMENTARY CUMULATIVE DISTRIBUTION FUNCTION FOR EARLY FATALITIES RISK FOR RELEASE CATEGORY SR6H-100C FOR 2-MILE EVACUATION (RUN NUMBER 591)

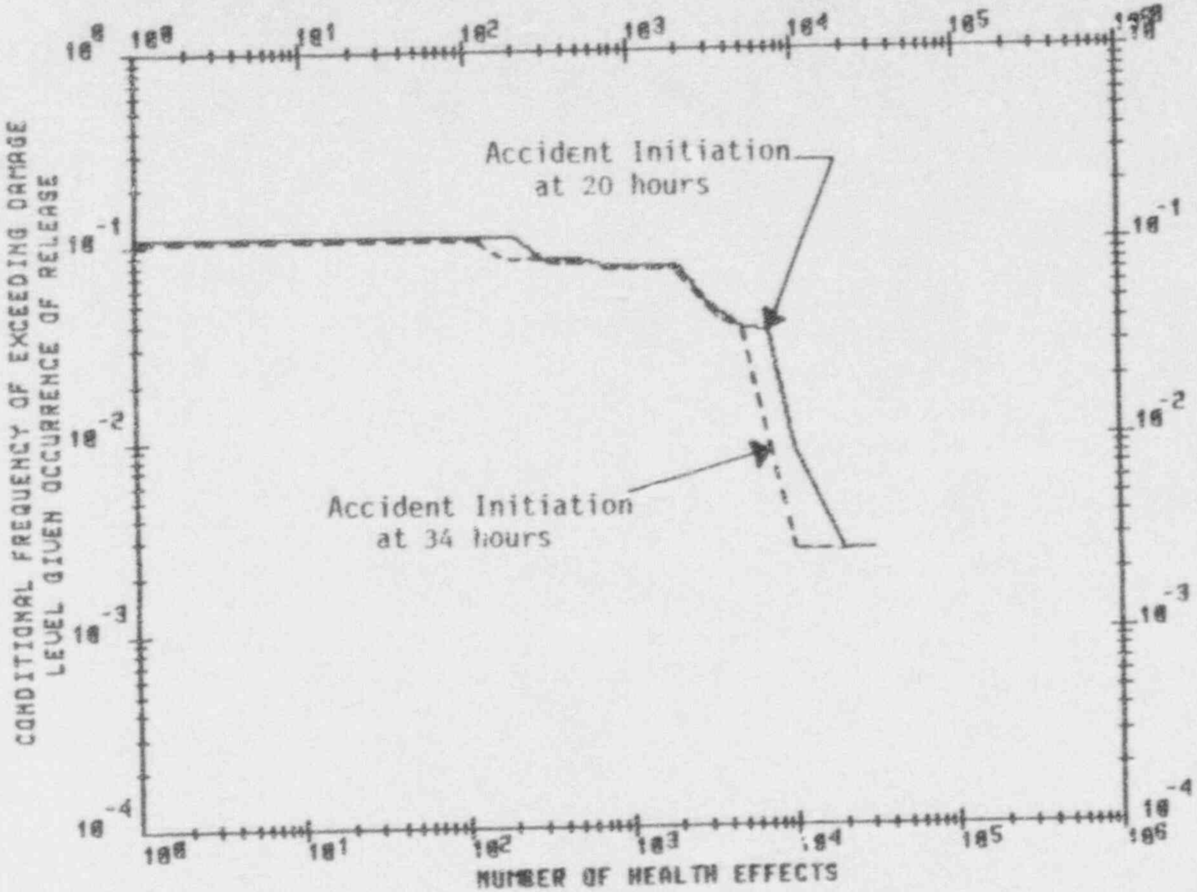


FIGURE 10-5. COMPARISON OF CRACIT RESULTS FOR SR6H-C WITH DIFFERENT INITIATION TIMES

TABLE 10-1 PLANT DAMAGE STATE MATRIX FOR SHUTDOWN EVENTS

CONDITIONS AT TIME OF CORE MELT THROUGH REACTOR VESSEL

<table>
<tr><th rowspan="3">RCS PRESSURE</th><th rowspan="3">REACTOR CAVITY</th><th colspan="4">CONTAINMENT BOUNDARY</th></tr>
<tr><th>ISOLATED</th><th colspan="3">NON-ISOLATED OR BYPASSED</th></tr>
<tr><th>D</th><th>≤ 3" Dia.
P</th><th>3"-18" Dia
F</th><th>OPEN HATCH
H</th></tr>
<tr><td rowspan="2">LOW
15 - 60 psia</td><td>WET (R1)</td><td>R1D</td><td>R1P</td><td rowspan="6">MODELED
AS
OPEN
HATCH
(H)</td><td>R1H</td></tr>
<tr><td>DRY (R2)</td><td>R2D</td><td>R2P</td><td>R2H</td></tr>
<tr><td rowspan="2">MEDIUM
60 - 700 psia</td><td>WET (R3)</td><td colspan="2" rowspan="2">(1)</td><td rowspan="2">(1)</td></tr>
<tr><td>DRY (R4)</td></tr>
<tr><td rowspan="2">HIGH
700 - 2500 psia</td><td>WET (R5)</td><td colspan="2">(2)</td><td>(2)</td></tr>
<tr><td>DRY (R6)</td><td>R6D</td><td>R6P</td><td>R6H</td></tr>
</table>

Section 10.1.2 describes the rules and assumptions for using only 9 of the originally defined plant damage states.

(1) Modeled as high pressure sequences

(2) No sequences identified

TABLE 10-2
CONTAINMENT ISOLATION VALVE EVALUATION

SIZE (dia. - in.)	VALVE ID #	PEN #	IRC/ ORC	TYPE	EVALUATION
36.00	CAP-V1	HVAC1	ORC	AOV	Normally open, explicitly modeled
36.00	CAP-V2	HVAC1	IRC	AOV	Normally open, explicitly modeled
36.00	CAP-V3	HVAC2	IRC	AOV	Normally open, explicitly modeled
36.00	CAP-V4	HVAC2	ORC	AOV	Normally open, explicitly modeled
30.00	MS-V86	X1	ORC	MOV	Requires SGTR to become release path
30.00	MS-V88	X2	ORC	MOV	Requires SGTR to become release path
30.00	MS-V90	X3	ORC	MOV	Requires SGTR to become release path
30.00	MS-V92	X4	ORC	MOV	Requires SGTR to become release path
18.00	FW-V39	X6	ORC	AOV	Requires SGTR to become release path
18.00	FW-V30	X5	ORC	AOV	Requires SGTR to become release path
18.00	FW-V48	X7	ORC	AOV	Requires SGTR to become release path
18.00	FW-V57	X8	ORC	AOV	Requires SGTR to become release path
16.00	CBS-V14	X60	IRC	MOV	Normally closed, water filled system
16.00	CBS-V8	X61	IRC	MOV	Normally closed, water filled system
12.00	CC-V121	X21	IRC	AOV	No direct contact with RCS or Containment
12.00	CC-V122	X21	ORC	AOV	No direct contact with RCS or Containment
12.00	CC-V168	X20	ORC	AOV	No direct contact with RCS or Containment
12.00	CC-V175	X23	ORC	AOV	No direct contact with RCS or Containment
12.00	CC-V176	X23	IRC	AOV	No direct contact with RCS or Containment
12.00	CC-V256	X22	IRC	AOV	No direct contact with RCS or Containment
12.00	CC-V257	X22	ORC	AOV	No direct contact with RCS or Containment
12.00	CC-V57	X20	IRC	AOV	No direct contact with RCS or Containment
12.00	RC-V23	X9	IRC	MOV	Considered in plant model
12.00	RC-V88	X10	IRC	MOV	Considered in plant model
12.00	RH-V70	X13	ORC	MOV	Multiple check valves in line
10.00	CGC-V45	X38	ORC	MAN	Check valve in line
10.00	CGC-V46	X38	IRC	CHECK	Check valve
8.00	RH-V26	X12	ORC	MOV	Multiple check valves in line
8.00	CBS-V11	X14	ORC	MOV	Check valve and locked closed valve in line
8.00	CBS-V12	X14	IRC	CHECK	Check valve
8.00	CBS-V17	X15	ORC	MOV	Check valve and locked closed valve in line
8.00	CBS-V18	X15	IRC	CHECK	Check valve
8.00	COP-V1	X18	ORC	AOV	Normally open, explicitly modeled
8.00	COP-V2	X18	IRC	AOV	Normally open, explicitly modeled
8.00	COP-V3	X16	IRC	AOV	Normally open, explicitly modeled

TABLE 10-2
CONTAINMENT ISOLATION VALVE EVALUATION

Sheet 2 of 4

SIZE (dia. - in.)	VALVE ID #	PEN #	IRC/ ORC	TYPE	EVALUATION
8.00	COP-V4	X16	ORC	AOV	Normally open, explicitly modeled
8.00	RH-V14	X11	ORC	MOV	Multiple check valves in line
8.00	RH-V32	X13	ORC	MOV	Multiple check valves in line
8.00	RH-V50	X13	IRC	CHECK	Check valve
8.00	RH-V51	X13	IRC	CHECK	Check valve
6.00	CC-V1092	X48	ORC	MOV	Requires thermal barrier HX tube leak
6.00	CC-V1095	X48	ORC	MOV	Requires thermal barrier HX tube leak
6.00	CC-V1101	X49	ORC	MOV	Requires thermal barrier HX tube leak
6.00	CC-V1109	X49	ORC	MOV	Requires thermal barrier HX tube leak
6.00	RH-V15	X11	IRC	CHECK	Multiple check valves in line
6.00	RH-V29	X12	IRC	CHECK	Multiple check valves in line
6.00	RH-V30	X12	IRC	CHECK	Multiple check valves in line
6.00	RH-V31	X11	IRC	CHECK	Multiple check valves in line
4.00	FP-V588	X38	IRC	CHECK	Check valve
4.00	FP-V592	X38	ORC	MAN	Locked closed, check valve in line
4.00	FW-V76	X5	ORC	CHECK	Requires SGTR to become release path
[illegible]	FW-V82	X6	ORC	CHECK	Requires SGTR to become release path
[illegible]	FW-V88	X7	ORC	CHECK	Requires SGTR to become release path
4.00	FW-V94	X8	ORC	CHECK	Requires SGTR to become release path
4.00	MS-V204	X1	ORC	MOV	Requires SGTR to become release path
4.00	MS-V205	X2	ORC	MOV	Requires SGTR to become release path
4.00	MS-V206	X3	ORC	MOV	Requires SGTR to become release path
4.00	MS-V207	X4	ORC	MOV	Requires SGTR to become release path
4.00	SI-V102	X25	ORC	MOV	Multiple check valves in line
4.00	SI-V114	X27	ORC	MOV	Multiple check valves in line
4.00	SI-V138	X24	ORC	MOV	Multiple check valves in line
4.00	SI-V139	X24	ORC	MOV	Multiple check valves in line
4.00	SI-V77	X26	ORC	MOV	Multiple check valves in line
3.00	CS-V143	X33	ORC	MOV	Check valve in line
3.00	CS-V144	X33	IRC	CHECK	Check valve
3.00	CS-V149	X37	IRC	MOV	Could be open
3.00	CS-V150	X37	ORC	AOV	Could be open
3.00	RC-V24	X9	IRC	RELIEF	Relieves inside containment
3.00	RC-V89	X10	IRC	RELIEF	Relieves inside containment
3.00	RMW-V29	X36	IRC	CHECK	Check valve

TABLE 10-2
CONTAINMENT ISOLATION VALVE EVALUATION

Sheet 3 of 4

SIZE (dia. - in.)	VALVE ID #	PEN #	IRC/ ORC	TYPE	EVALUATION
3.00	RMW-V30	X36	ORC	AOV	Check valve in line
3.00	SI-V140	X24	IRC	CHECK	Check valve
3.00	WLD-V81	X32	IRC	AOV	Could be open
3.00	WLD-V82	X32	ORC	AOV	Could be open
2.00	CGC-V14	X72	IRC	MOV	Normally locked closed
2.00	CGC-V15	X72	ORC	MAN	Normally locked closed
2.00	CGC-V28	X71	IRC	MOV	Normally locked closed
2.00	CGC-V36	X71	ORC	MAN	Normally locked closed
2.00	CGC-V43	X38	ORC	MAN	Normally locked closed
2.00	CGC-V44	X38	ORC	MAN	Normally locked closed
2.00	CS-V154	X31	ORC	MOV	Check valves in line
2.00	CS-V158	X30	ORC	MOV	Check valves in line
2.00	CS-V162	X29	ORC	MOV	Check valves in line
2.00	CS-V166	X28	ORC	MOV	Check valves in line
2.00	CS-V167	X37	ORC	MOV	Could be open
2.00	CS-V168	X37	IRC	MOV	Could be open
2.00	CS-V20	X29	IRC	CHECK	Check valve
2.00	CS-V36	X30	IRC	CHECK	Check valve
2.00	CS-V4	X28	IRC	CHECK	Check valve
2.00	CS-V52	X31	IRC	CHECK	Check valve
2.00	SA-V1042	X67	IRC	MAN	No direct contact with RCS or Containment
2.00	SA-V229	X67	ORC	MAN	No direct contact with RCS or Containment
2.00	SB-V10	X64	ORC	AOV	Requires SGTR to become release path
2.00	SB-V11	X65	ORC	AOV	Requires SGTR to become release path
2.00	SB-V12	X66	ORC	AOV	Requires SGTR to become release path
2.00	SB-V9	X63	ORC	AOV	Requires SGTR to become release path
2.00	SF-V86	X39	IRC	MAN	Open sometimes
2.00	SF-V87	X39	ORC	MAN	Open sometimes
2.00	SI-V106	X25	IRC	CHECK	Check valve
2.00	SI-V110	X25	IRC	CHECK	Check valve
2.00	SI-V118	X27	IRC	CHECK	Check valve
2.00	SI-V122	X27	IRC	CHECK	Check valve
2.00	SI-V126	X27	IRC	CHECK	Check valve
2.00	SI-V130	X27	IRC	CHECK	Check valve
2.00	SI-V81	X26	IRC	CHECK	Check valve

TABLE 10-2
CONTAINMENT ISOLATION VALVE EVALUATION

SIZE (dia. - in.)	VALVE ID #	PEN #	IRC/ ORC	TYPE	EVALUATION
2.00	SI-V86	X26	IRC	CHECK	Check valve
2.00	VG-FV1661	X17	ORC	SOV	Could be open
2.00	VG-FV1712	X17	IRC	SOV	Could be open
1.50	CC-V410	X21	IRC	RELIEF	Relieves inside containment
1.50	CC-V474	X22	IRC	RELIEF	Relieves inside containment
1.50	CC-V840	X23	IRC	RELIEF	Relieves inside containment
1.50	CC-V845	X20	IRC	RELIEF	Relieves inside containment
1.50	DM-V18	X36	IRC	RELIEF	Relieves inside containment
1.50	WLD-V213	X32	IRC	RELIEF	Relieves inside containment

TABLE 10-3

CONTAINMENT PENETRATIONS
UNAVAILABILITY

Initiating Event Type (1)	RCS Cond (2)	Equipment Hatch Unavailability			Purge Lines (CAP & COP) Unavailability (11) (12)	Total Unavail. for Large Openings (Top Event [illegible]	Small Penet. Unavail. (13) (Top Event SP)
		Fraction of Time Off	Probability Not Recovered	Unavailability			
		FTO	PNR	Q(EQH)=FTO*PNR	Q(PL)	Q(EH)=Q(EQH)[illegible]	Q(SP)
Procedure Transient	W	3.3E-2(3)	2.3E-2(10)	7.6E-4	2.1E-3	2.9E-3 (EH1)	1.7E-2 (SP1)
Procedure Transient	X	0.0(4)	NA	0.0	5.1E-3	5.1E-3 (EH2)	4.0E-2 (SP2)
Procedure Transient	Y	0.0(5)	NA	0.0	2.1E-3	2.1E-3 (EH3)	1.7E-2 (SP1)
LOCA L1	W	3.3E-2(6)	1.0	3.3E-2	5.1E-3	3.8E-2 (EH5)	4.0E-2 (SP2)
LOCA LP	W	3.3E-2(6)	1.0	3.3E-2	5.1E-3	3.8E-2 (EH5)	1.0 (SPF)
LOCA L3	W	0.0(7)	NA	0.0	5.1E-3	5.1E-3 (EH2)	1.0 (SPF)
LOCA L5 & L6	Y	0.0(8)	NA	0.0	5.1E-3	5.1E-3 (EH2)	4.0E-2 (SP2)
LOCA LS	W	3.3E-2(9)	1.0	3.3E-2	5.1E-3	3.8E-2 (EH5)	4.0E-2 (SP2)

TABLE 10-3

CONTAINMENT PENETRATIONS
UNAVAILABILITY

Initiating Event Type (1)	RCS Cond (2)	Equipment Hatch Unavailability: Fraction of Time Off FTO	Equipment Hatch Unavailability: Probability Not Recovered PNR	Equipment Hatch Unavailability: Unavailability Q(EQH)=FTO*PNR	Purge Lines (CAP & COP) Unavailability (11) (12) Q(PL)	Total Unavail. for Large Openings (Top Event EH) Q(EH)=Q(EQH)+Q(PL)	Small Penet. Unavail. (13) (Top Event SP) Q(SP)
LOSP & Hazards That Cause LOSP	X	0.0(9)	N/A	0.0	1.1E-4	1.1E-4 (EH4)	4.0E-2 (SP2)
	W	3.3E-2	1.0	3.3E-2	1.1E-4	3.3E-2 (EH6)	1.7E-2 (SP1)
Other Hazards Except Seismic	X	0.0(9)	N/A	0.0	5.1E-3	5.1E-3 (EH2)	4.0E-2 (SP2)
	W	3.3E-2	4.2E-2	1.4E-3	2.1E-3	3.5E-3 (EH7)	1.7E-2 (SP1)
Other Internal Trans-ients	X	0.0(9)	N/A	0.0	5.1E-3	5.1E-3 (EH2)	4.0E-2 (SP2)
	W	3.3E-2	4.2E-2	1.4E-3	2.1E-3	3.5E-3 (EH7)	1.7E-2 (SP1)
Seismic Black-out	X	0.0(9)	N/A	0.0	1.1E-4	1.1E-4 (EH4)	4.0E-2 (SP2)
	W	3.3E-2	1.0	3.3E-2	1.1E-4	3.3E-2 (EH6)	4.0E-2 (SP2)
Seismic LOCA	W	3.3E-2(9)	1.0	3.3E-2	1.1E-4	3.3E-2 (EH6)	4.0E-2 (SP2)

TABLE 10-3

CONTAINMENT PENETRATIONS
UNAVAILABILITY

NOTES:

(1) Initiating Events are described and quantified in Table 3-1.

(2) RCS Conditions are defined as:

W - RCS full and intact
X - RCS drained and open
Y - RCS at refueling level

(3) FTO(W) = [1 outage/yr * 2 removals/outage * 24 hrs/removal]/[1455 hrs in W/yr] = 0.033.

This quantification is based on administrative controls require planned removal and immediate replacement of the equipment hatch. Therefore, the duration the hatch is off per removal is estimated to be between 12 and 36 hrs, with a best estimate of 24 hours/removal. The equipment hatch is expected to be off no more than once a year and at least once every four years. Conservatively, once a year (1 outage per year) is used in the point estimate. Given that the hatch needs to be removed, as a minimum it is removed once and could be removed twice (once at the beginning and again at the end of the outage). Three removals is considered an upper bound and 2 removals per outage is used as a best estimate. The annual average time in RCS Condition W is from Table 9-3.

(4) "FTO(X) = 0.0" is based on Administrative Controls that preclude removal during draindown (Condition X).

(5) While in RCS Condition Y (refueling), the hatch must be on during fuel movement per Technical Specifications. Thus, FTO(Y) = 0.0.

(6) LOCAs L1 and LP occur due to overpressure in RCS Condition W (see Note 2). Thus, FTO(L1,LP) = FTO(W) = 0.045. Since the LOCAs are likely to reduce the time available before core damage, no credit for recovery is given. Thus, PNR = 1.0.

(7) LOCA L3 occurs early in the shutdown while the plant is in Mode 4 and the hatch is required to be on. Thus, FTO(L3) = 0.0.

TABLE 10-3

CONTAINMENT PENETRATIONS
UNAVAILABILITY

(8) LOCAs L5 and L6 occur in Procedure Event Tree 3 in RCS Condition Y (see Note 4). Thus, FTO(L5,L6) = 0.0.

(9) These events could occur anytime during an outage and the fraction of time the hatch is off depends upon the RCS Condition (W or X) the plant is in. Hatch non-recovery is guaranteed (PNR = 0.0) based on the following:

- for LOCA L5, the time available before core damage is reduced.
- for LOSP1 and hazards that cause LOSP, recovery is not possible because power to the polar crane is not available.
- for Seismic events, offsite power is likely to be lost and thus the polar crane cannot be operated.

(10) Hatch recovery is modeled for the conditions when other hazards or internal events do not result in a LOCA or non-recoverable loss of offsite power. The probability that the equipment hatch is not replaced in RCS Condition W, PNR(W), is quantified from the probability of operator error in replacing the hatch $OP1_{EH}$ plus the hardware failure of the polar crane motors HW_{EH}. Thus, $OP1_{EH}$ = 1.3E-2 (mean) from Section 6.4.2. Hardware failure is dominated by the three polar crane motors failing to start on demand. HW_{EH} = 3 * ZIPMSS = 9.9E-3 where ZIPMSS = 3.29E-3 from Section 9.1. Thus, the probability of not recovering the hatch is: PNR(W) = $OP1_{EH}$ + HW_{EH} = 2.3E-2. In the case of fire or other hazards where offsite power is available, less time is assumed available to replace the hatch due to responding to the hazard. Thus, $OP2_{EH}$ = 3.2E-2 (mean) from Section 6.4.2. Thus, PNR (Hazards) = $OP2_{EH}$ + HW_{EH} = 4.2E-2.

(11) Hardware and human failures are considered for unavailability of the containment online purge (COP) and containment air purge (CAP) isolation valves. The following are used for hardware and human factor contributions:

o Hardware unavailability assumes all valves are open initially and one train of valves are unavailable 10% of the time. Failure occurs if any one of 4 paths fails to close when the second valve is unavailable [4 X 0.1 X 2.66E-4 (Table 9-1, ZIVAOF) = 1.1E-4]

TABLE 10-3

CONTAINMENT PENETRATIONS
UNAVAILABILITY

- Human failure probabilities are developed by estimating the uncertainty and assuming a lognormal distribution as follows:

  a. $OP1_{PL}$ = 2.0E-3 (mean)

     This value is used for RCS Conditions W or Y where > 10 hrs are available for operator actions. (See Section 6.4.2).

  b. $OP2_{PL}$ = 5.0E-3 (mean)

     This value is used for RCS Condition X where > 2 hrs are available for operator actions. (See Section 6.4.2).

The following summarizes unavailability of the CAP/COPs:

- Procedure transients with RCS Condition W or Y

  $Q(PL)_W = Q(PL)_Y = HW + OP1_{PL}$

  $= 1.1E{-}4 + 2.0E{-}3 = 2.1E{-}3$

- Procedure transients with RCS Condition X and LOCAs that can reduce the time available for operator actions

  $Q(PL)_X = Q(PL)_{LOCA}$

  $= HW + OP2_{PL} = 1.1E{-}4 + 5.0E{-}3 = 5.1E{-}3$

- LOSP1, hazards that cause LOSP, and Control Room/Cable Spreading Room fires are most likely to initiate valve closure from loss of air. Station blackout dominates and air compressors require offsite power or operator actions early in the sequence for non-blackouts. Therefore, unavailability is hardware only.

  $Q(PL)_{LOSP} = HW = 1.1E{-}4$

CONTAINMENT PENETRATIONS
UNAVAILABILITY

- o Other internal events and hazards that require operator actions depend on the RCS Condition X versus Y and W. Unavailablity is estimated as above for $Q(PL)_{W,Y}$ and $Q(PL)_X$.

(12) The probability that the personnel airlock would not be closed is assumed to be unlikely and small in comparison to the equipment hatch unavailability and purge line unavailabilities.

(13) The probability that smaller penetrations remain open is similar to the COP/CAP assessment in Note 10 in that hardware and human failures contribute to unavailability. However, in this case there may be several more valves to close and some may require closure locally. In addition, most paths have several valves in series that could be closed if another fails. Many paths are filled with water, contain a check valve, and/or are closed systems. Therefore, it is assumed that unavailability is dominated by the human element, i.e., the probability that administrative controls break down or errors occur while implementing isolation procedures. The following estimated unavailabilities are based on administrative controls, procedures, and training that recognize the importance of containment isolation:

For events with RCS Condition W or Y, except for LOCAs and seismic events:

$Q(SP)_W = Q(SP)_Y = OP1_{SP} = 1.7E-2$ (See Section 6.4.2)

For events with RCS Condition X and for LOCAs and seismic events:

$Q(SP)_X = OP2_{SP} = 4.0E-2$ (See Section 6.4.2)

LOCA LP and L3 are containment bypass LOCAs and are likely to be released through water. However, these are modeled as a guaranteed small opening.

TABLE 10-4

SHUTDOWN AND POWER ANALOGOUS SOURCE TERMS

SHUTDOWN RELEASE CATEGORY	POWER RELEASE CATEGORY	REFERENCE	REMARKS
SR1D	$\overline{S3}$	SSPSA, Chapter 11 and Appendix H	
SR1P	$\overline{S2}$	SSPSA, Chapter 11 and Appendix H	
SR1H	$\overline{S6}$V	SSPSA, Chapter 11 and Appendix H	Conservative bounding case for $\overline{S6}$
SR2D	$\overline{S3}$V	SSPSA, Chapter 11 and Appendix H	
SR2P	$\overline{S2}$V	SSPSA, Chapter 11 and Appendix H	
SR2H	$\overline{S6}$V	SSPSA, Chapter 11 and Appendix H	
SR6D	$\overline{S3}$V	SSPSA, Chapter 11 and Appendix H	Release times: TE scenario
SR6P	$\overline{S2}$V	SSPSA, Chapter 11 and Appendix H	Release times: TE scenario
SR6H	$\overline{S1}$-C, $\overline{S6}$V-R	SSPSA, Chapter 11 and Appendix H	Release times: TE scenario

TABLE 10-5

SOURCE TERM TIME HISTORIES (HOURS)

SHUTDOWN RELEASE CATEGORY	START OF ACCIDENT	EVACUATION TIME	START OF PUFF 1	START OF PUFF 2	END OF RELEASE
$\overline{S2}$ SR1P-C SR1P-R	0 81.9 472.5	7 88.9 479.5	0.79 88.9 481.6	1.5 89.7 485.6	31.0 144.2 569.3
$\overline{S2}$V SR2P-C SR2P-R	0 104.4 627.3	7 111.4 634.3	0.074 108.1 637.3	0.55 110.7;111.4 641.5	30.1 170.7 735.7
TE($\overline{S2}$V) SR6P-C SR6P-R	0 32.4 475.2	7 39.4 482.2	2 40.7 492.7	2.48 41.8 494.9	30.1 83.8 572.2
$\overline{S6}$V SR1H-C SR1H-R	0 81.9 472.5	7 88.9 479.5	3.67 87.2 481.6	------ 88.9 ------	34.0 139.2 561.9
$\overline{S6}$V SR2H-C SR2H-R	0 90 534.6	7 97 541.6	1.244 93.5 544.1	------ 97.0 ------	31.2 149.9 632.4
TE($\overline{S1}$-C;$\overline{S6}$V-R) SR6H-C SR6H-R	0 34.2 491.4	7 41.2 498.4	2 42.5 508.4	------ ------ ------	2.7-C;32.2-R 43.4 593.3
$\overline{S3}$ SR1D-C SR1D-R	0 81.9 472.5	7 88.9 479.5	0.79 88.9 481.6	22.8 131.5 550.3	31.8 145.5 571.1
$\overline{S3}$V SR2D-C SR2D-R	0 98.1 596.7	7 105.1 603.7	4.368 105.1 606.5	------ ------ ------	29.3 146.4 677.7
TE($\overline{S3}$V) SR6D-C SR6D-R	0 32.4 464.4	7 39.4 471.4	2 40.7 481.4	------ ------ ------	26.98 79.6 553.2

TABLE 10-6 SUMMARY OF SHUTDOWN EVENT SOURCE TERMS

RELEASE CATEGORY	PUFF	START OF RELEASE (HR)	DURATION (HR)	WARNING TIME (HR)	RELEASE FRACTIONS Kr-Xe	org-I	I2-Br	Cs-Rb	Te	Ba-Sr	Ru	La
SR1P-C	1	88.9	1.0	6.0	1.6E-03	1.1E-05	1.1E-03	1.3E-03	2.4E-04	1.6E-04	4.8E-05	4.6E-06
	2	89.9	23.0		3.8E-01	2.7E-03	5.1E-03	1.3E-01	2.4E-02	1.6E-02	4.7E-03	4.7E-04
SR1P-R	1	481.6	4.0	8.1	1.6E-03	1.1E-05	1.1E-03	1.3E-03	2.4E-04	1.6E-04	4.8E-05	4.6E-06
	2	485.6	20.0		2.2E-01	1.5E-03	2.8E-03	7.4E-02	1.3E-02	9.2E-03	2.7E-03	2.7E-04
SR2P-C	1*	108.1	2.0	2.7	2.4E-07	1.7E-09	2.3E-07	2.8E-07	3.5E-08	2.3E-08	6.9E-09	6.9E-10
	2*	110.1	1.0		1.2E-02	8.6E-05	4.0E-03	1.0E-02	1.8E-03	1.2E-03	3.7E-04	3.7E-05
	3	111.1	21.0		1.4E-01	9.6E-04	1.7E-03	7.4E-02	7.8E-02	8.5E-03	6.3E-03	1.0E-03
SR2P-R	1	637.3	4.0	9.0	2.4E-07	1.7E-09	2.3E-07	2.8E-07	3.5E-08	2.3E-08	6.9E-09	6.9E-10
	2	641.3	20.0		8.3E-02	5.9E-04	1.8E-03	4.7E-02	4.7E-02	5.3E-03	3.8E-03	6.2E-04
SR6P-C	1	40.7	1.0	7.3	2.4E-07	1.7E-09	2.3E-07	2.8E-07	3.5E-08	2.3E-08	6.9E-09	6.9E-10
	2	41.7	23.0		2.2E-01	1.5E-03	4.7E-03	1.2E-01	1.2E-01	1.3E-02	9.6E-03	1.6E-03
SR6P-R	1	492.5	2.0	16.5	2.4E-07	1.7E-09	2.3E-07	2.8E-07	3.5E-08	2.3E-08	6.9E-09	6.9E-10
	2	494.7	22.0		1.1E-01	8.0E-04	2.5E-03	6.2E-02	6.2E-02	7.1E-03	5.1E-03	8.2E-04
SR1H-C	1*	87.2	2.0	4.3	2.0E-02	1.3E-04	1.7E-02	1.8E-02	2.9E-03	1.9E-03	5.7E-04	5.7E-05
	2	89.2	22.0		3.9E-01	2.8E-03	7.1E-02	1.8E-01	1.8E-01	2.0E-02	1.4E-02	2.2E-03
SR1H-R	1	481.6	24.0	8.1	2.7E-01	1.9E-03	5.4E-02	1.3E-01	1.2E-01	1.4E-02	9.9E-03	1.6E-03
SR2H-C	1*	93.5	3.0	2.5	1.5E-01	1.1E-03	9.8E-02	1.1E-01	2.0E-02	1.4E-02	4.1E-03	4.1E-04
	2	95.5	21.0		3.2E-01	2.0E-03	3.2E-02	1.2E-01	1.5E-01	1.3E-02	1.1E-02	1.9E-03
SR2H-R	1	544.1	24.0	8.5	2.4E-01	1.7E-03	4.9E-02	1.2E-01	1.1E-01	1.3E-02	9.0E-03	1.4E-03
SR6H-C**	1	42.5	0.9	7.3	9.4E-01	6.6E-03	8.0E-01	7.4E-01	3.9E-01	9.3E-02	4.6E-01	2.8E-03
SR6H-R	1	508.4	24.0	16.0	2.5E-01	1.8E-03	5.1E-02	1.2E-01	1.1E-01	1.4E-02	9.3E-03	1.5E-03
SR1D-C**	1	88.9	22.0	6.0	4.5E-03	3.0E-05	6.9E-05	7.0E-04	1.3E-04	8.5E-05	2.5E-05	2.5E-06
	2	110.9	2.0		2.0E-01	1.4E-03	2.0E-03	2.4E-02	4.4E-03	2.9E-03	8.7E-04	8.7E-05
SR1D-R**	1	481.6	22.0	8.1	4.5E-03	3.0E-05	6.9E-05	7.0E-04	1.3E-04	8.5E-05	2.5E-05	2.5E-06
	2	503.6	2.0		2.0E-01	1.4E-03	2.0E-03	2.4E-02	4.4E-03	2.9E-03	8.7E-04	8.7E-05
SR2D-C**	1	105.1	24.0	6.0	4.8E-04	3.4E-06	3.2E-05	1.6E-04	1.4E-04	1.9E-05	1.2E-05	1.9E-06
SR2D-R**	1	606.5	24.0	8.8	4.8E-04	3.4E-06	3.2E-05	1.6E-04	1.4E-04	1.9E-05	1.2E-05	1.9E-06
SR6D-C**	1	40.7	24.0	7.3	4.8E-04	3.4E-06	3.2E-05	1.6E-04	1.4E-04	1.9E-05	1.2E-05	1.9E-06
SR6D-R**	1	481.4	24.0	16.0	4.8E-04	3.4E-06	3.2E-05	1.6E-04	1.4E-04	1.9E-05	1.2E-05	1.9E-06

* RELEASE STARTS BEFORE EVACUATION

** RELEASE ENERGY RATE = 210 Mcal/s
THE OTHER RELEASE ENERGIES ARE < 10 Mcal/s

TABLE 10-7

MODEL FOR PROCEDURE TREE FRACTIONAL CONTRIBUTIONS TO PLANT DAMAGE STATE FREQUENCY

		PLANT DAMAGE STATE						
OUTAGE TYPE	PROCEDURE TREE	R1D,P,H	R2D*	R2P	R2H	R6D*	R6P	R6H
A	A1	0		.065	.227		.525	.493
	A6	0		.014	.049		.025	.026
B	B1	0		.023	.078		.168	.186
	B2	0		.229	.123		0.0	0.0
	B5	0		.021	.074		.029	.039
	B6	0		0.0	0.0		0.0	0.0
C	C1	0		0.0	0.0		.017	0.0
	C2	0		0.0	0.0		.005	0.0
	C3	1.0		0.0	0.0		0.0	0.0
	C4	0		.579	.210		0.0	0.0
	C5	0		.064	.223		.221	.248
	C6	0		.005	.016		.010	.008

* Plant Damage States R2D and R6D not modeled since they do not contribute significantly to early releases.

TABLE 10-8

UNCERTAINTY DISTRIBUTIONS FOR TIME TO ACCIDENT INITIATION AND CORE DAMAGE FOR PLANT DAMAGE STATES
(Time in Hours)

PLANT DAMAGE STATE	DISTRIBUTION	5th	10th	20th	50th	MEAN	95th
		PERCENTILE					
R1D,R1P,R1H	Initiation:	150	160	178	229	232	333
	Core Damage:	156	166	185	236	240	342
R2P	Initiation:	79	176	361	809	883	1848
	Core Damage:	90	191	369	820	896	1882
R2H	Initiation:	30	47	124	718	859	1963
	Core Damage:	44	62	140	731	880	1999
R6P	Initiation:	23	29	43	157	561	1938
	Core Damage:	36	43	58	176	583	1975
R6H	Initiation:	23	28	40	165	607	1945
	Core Damage:	36	42	55	184	629	1981

TABLE 10-9

UNCERTAINTY DISTRIBUTIONS FOR TIME TO ACCIDENT INITIATION IN A SPECIFIC PROCEDURE TREE
(Time in Hours)

PROCEDURE TREE	PERCENTILE 5th	10th	20th	50th	MEAN	95th
A1 (W)	28	37	54	130	171	610
A6 (W)	74	202	245	255	330	1149
B1 (W)	18	20	22	32	34	64
B2 (X)	92	137	229	495	528	981
B5 (W)	627	765	950	1015	1057	1751
B6 (W)	683	850	1032	1069	1119	1815
C1 (W)	54	57	62	77	80	124
C2 (W)	90	101	105	124	129	184
C3 (Y)	150	160	178	229	232	333
C4 (X)	375	442	581	986	1035	1740
C5 (W)	1142	1323	1744	1830	1848	2634
C6 (W)	1292	1533	1865	1959	1980	2772

TABLE 10-10

COMPARISON OF ACCIDENT INITIATION TIME UNCERTAINTY DISTRIBUTIONS WITH TIMES ASSUMED IN SOURCE TERM AND CONSEQUENCE ANALYSIS

RELEASE CATEGORY	VALUE USED FOR REALISTIC SOURCE TERM (HOURS)	LOCATION ON FINAL UNCERTAINTY DISTRIBUTION	VALUE USED FOR CONSERVATIVE SOURCE TERM (HOURS)	LOCATION ON FINAL UNCERTAINTY DISTRIBUTION
SR1-D,P,d	473	Mean + 233 hrs.	82	Less than 5th Percentile
SR2D	597	*	98	*
SR2P	627	Mean - 256 hrs.	104	6th Percentile
SR2H	535	Mean - 324 hrs.	90	16th Percentile
SR6D	464	*	32	*
SR6P	475	Mean - 86 hrs.	32	12th Percentile
SR6H	492	Mean - 115 hrs.	34	13th Percentile

* Type D source terms were not analyzed for consequences because of negligible risk contributions; this determination was made by comparing frequencies and release fractions with different release categories.

TABLE 10-11

CONDITIONAL CONSEQUENCE RESULTS

RELEASE CATEGORY	SOURCE TERM	EVACUATION CASE	RUN NO.	EARLY FATALITIES INSIDE 1.5 MILES	TOTAL EARLY FATALITIES	WHOLE BODY DOSE VS DIST. CURVE	CCDF - EARLY FATALITY CURVE
SR2P	R	0	578	0.0	0.0	10-3a	10-4a
		2	588	0.0	0.0	-	b
	C	0	570	9.6	9.6	b	c
		2	592	0.0	0.0	-	d
SR2H	R	0	574	0.48	0.48	c	e
		2	586	0.0	0.0	-	f
	C	0	566	69.1	123.	d	g
		2	590	0.006	0.28	-	h
SR6P	R	0	580	0.15	0.15	e	i
		2	589	0.0	0.0	-	j
	C	0	572	133.	135.	f	k
		2	593	0.0	0.02	-	l
SR6H	R	0	576	0.57	0.57	g	m
		2	587	0.0	0.0	-	n
	C	0	568	0.37	394.	h	o
		2	591	0.0	390.	-	p

11.0 REFERENCES

1. Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment", prepared for Public S ,ice Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983.

2. Fleming, K. N., et al, "Seabrook Station Risk Management and Emergency Planning Study", Pickard, Lowe and Garrick, Inc., prepared for Public Service Company of New Hampshire, New Hampshire Yankee Division, PLG-0432, December 1985.

3. Fleming, K. N., et al, "Seabrook Station Emergency Planning Sensitivity Study", Pickard, Lowe and Garrick, Inc., prepared for New Hampshire Yankee Division of Public Service Company of New Hampshire, PLG-0465, April 1986.

4. J. DeVincentis, New Hampshire Yankee, "Response to Request for Additional Information (RAIs)", SBN-1225, letter to S. M. Long, NRC, October 31, 1986.

5. Pratt, T., et al., "Review of Seabrook Station Emergency Planning Sensitivity Studies", Brookhaven National Laboratory Report FIN A-3825, March 1987.

6. Bley, D. C., J. W. Stetkar et al, "Zion Nuclear Plant Residual Heat Removal PRA", EPRI/NSAC Report NSAC-84, prepared by Pickard, Lowe, and Garrick, Inc., July 1985.

7. Vine, G., and Layman, W., "Residual Heat Removal Experience Review and Safety Analysis, Pressurized Water Reactors", Nuclear Safety Analysis Center, NSAC-52, January 1983.

8. Wyckoff, H., "Losses of Off-Site Power at U.S. Nuclear Power Plants", EPRI/NSAC Report NSAC-80, July 1984.

9. Wesley, D.A., Campbell, R.D., et al, Seismic Fragilities of Structures and Components at the Seabrook Generating Station, Units 1 and 2, Revision 1/NTS 1589.01, June 1986, NTS Engineering.

10. Control of Heavy Loads, Revision 2, United Engineers and Constructors, Inc., "Seabrook Station Response to NRC Generic Request for Additional Information Relating to NUREG-0612 'Control of Heavy Loads'", Revision No. 2, prepared for Public Service Company of New Hampshire, October 1985.

11. Seabrook Station Final Safety Analysis Report (FSAR), Amendment 61, January 1987.

12. "ETC9 (Event Tree Code 9)", Computer Code, Buttemer, F. R., Wheeler, D. M., Pickard, Lowe and Garrick, Inc., PLG-0466, April 1986 (Proprietary)

13. "MAXIMA6 Computer Code", Mikschl, T. J., Hubbard, F. R., Meade, T. B., Fenstermacher, T. E., Pickard, Lowe and Garrick, Inc., PLG-0465 (Proprietary), April 1986.

14. "SEIS4 (Seismic Risk Assessment)" Computer Code, Lin, J. C., Kaplan, S., Pickard, Lowe and Garrick, Inc., PLG-0287, January 1985 (Proprietary).

15. New Hampshire Yankee Division, PSNH, Production Technical Requirements Manual, Revision 2.

16. Seabrook Station Fire Protection of Safe Shutdown Capability, Volume I, Revision 3, November 1986.

17. Swain, Alan, et al, "Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications", NUREG/CR-1278, August 1983.

18. Swain, Alan, "Accident Sequence Evaluation Program, Human Reliability Analysis", NUREG/CR-4772, February 1987.

19. Seabrook Station Technical Specifications (NUREG-1207), October 1986.

20. Read, J. W. , et al, "STADIC4 Model for Frequency of Non-Recovery of Electric Power at Seabrook Station", Pickard, Lowe and Garrick, Inc., prepared for Public Service Company of New Hampshire, New Hampshire Yankee Division, PLG-0507, Rev. 1, May 1988.

21. WCAP-10982, "The Nuclear Design and Core Physics Characteristics of the Seabrook Station Unit 1, Cycle 1", December 1985 (Proprietary).

22. Fleming, K. N., et al, "Risk Management Actions to Assure Containment Effectiveness at Seabrook Station", Pickard, Lowe and Garrick, Inc., prepared for Public Service Company of New Hampshire, New Hampshire Yankee Division, PLG-0550, July 1987.

23. "STADIC4 Computer Code", Wakefield, D. J., Fleming, K. N., Pickard, Lowe and Garrick, Inc., PLG-0438 (Proprietary) October 1985.

Seabrook Station

PROBABILISTIC SAFETY STUDY

SHUTDOWN
(MODES 4, 5 and 6)

May 1988

New Hampshire
Yankee

SEABROOK STATION PROBABILISTIC SAFETY STUDY
SHUTDOWN (MODES 4, 5, AND 6)

By

Kenneth L. Kiper
James H. Moody, Jr.
(New Hampshire Yankee)

William Doskocil
(Yankee Atomic Electric Company)

Thomas J. Casey
(T. J. Casey Consulting)

Karl N. Fleming
(Pickard, Lowe and Garrick, Inc.)

May 1988

APPENDIX A

RESIDUAL HEAT REMOVAL EVENT DATA BASE

APPENDIX A

This Appendix contains a list of 107 actual losses or degradations of shutdown decay heat removal systems based on an extensive review of LER data from January 1982 to December 1986. This list updates the data in Appendix A of NSAC-52, "Residual Heat Removal Experience Review and Safety Analysis" (Reference 7), which contains summaries of 251 events which occurred between 1977 and 1981. The data in this Appendix has been categorized by the type of event and the cause of the failure, consistent with categories in NSAC-52.

The following is a list of the categories of events included in Appendix A.

TABLE A-1: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

TABLE A-2: LOSS OF FLOW - RCS INVENTORY REDUCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

TABLE A-3: LOSS OF REACTOR COOLANT INVENTORY VIA THE RHRS

TABLE A-4: LOSS OR DEGRADATION OF FLOW, OR LOSS OF COOLANT INVENTORY DUE TO AUTOMATIC INITIATION OF THE RECIRCULATION MODE OF LOW PRESSURE SAFETY INJECTION, INCLUDING RHRS PUMP TRIPS

TABLE A-5: LOSS OF FLOW OR DEGRADED COOLING DUE TO OTHER VALVE CLOSURES, OR EXCESSIVE PUMP/COOLER BYPASS FLOW

TABLE A-6: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

TABLE A-7: INTENTIONAL LOSS OR DEGRADATION OF RHRS FOR PLANNED MAINTENANCE

TABLE A-8: INABILITY TO ESTABLISH RHRS FLOW - DUE TO INABILITY TO OPEN RHRS SUCTION VALVES

TABLE A-9: RCS VOID FORMATION DURING RHRS OPERATIONS

TABLE A-10: MISCELLANEOUS LOSS OF RHRS EVENTS

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Zion-1 295-82011 820317	Mode 6	RHR suction valve 1MOV-RH8702 started to close due to an inadvertent opening of inverter 111 output breaker. The running pump was tripped. The inverter output breaker was reclosed, RHR suction valve 1MOV-RH8702 was reopened, and the RHR system was restored to operation within 3 minutes.	A contractor working in the Aux. Electric Room accidentally dropped a piece of sheet metal on inverter 111 output breaker causing it to open causing RHR suction pressure transmitter 1PT-403 to fail high which caused an auto-closure on 1MOV-RH8702.	Contractor personnel were informed of the necessity to be careful while working in this area.
McGuire-1 369-82053 820713	During plant cooldown and Mode de-escalation	Static inverter EVIA malfunctioned causing a residual heat removal system (ND) isolation valve to close. Operators restored ND flow, but not before loss of flow effected a transition from Mode 5 to Mode 4.	This is attributed to component failure of the Solid-state Controls, Inc. static inverter. Three capacitors in the output CVT capacitor bank failed and had deformed casings. The failed capacitors were replaced and the inverter returned to service.	The Inverter Corrective Maintenance Procedure will be modified to reflect the possibility of CVT Capacitor failure. The controlling procedure for unit shutdown was modified to preclude inadvertent loss of ND Flow.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Summer 395-82002 820916	Preop Testing	After calibrating the pressure transmitter for the RHR Train "A" suction isolation valve, the valve operator was reenergized. The suction isolation valve shut. The reactor operator tripped the Train "A" RHR pump due to loss of suction. There were no adverse consequences since the system has a minimum flow recirc. line and the pump was secured within one minute of the occurrence. Also, Train "B" RHR was operable.	After performing calibrations for RHR Train "A" suction isolation valve pressure transmitter, maintenance personnel left th. pressure switch in the test position. When the valve operator was reenergized, the valve shut due to the test signal.	Maintenance personnel were instructed to explicitly follow procedur: l guidelines.
Summer 395-82004 821015	Mode 5	In performing surveillance testing on RHR/COP pressure transmitter (PT 402) with the B Train RHR in operation, a test signal was generated. The B Train RHR header isolation valve (XVG 8702B) shut and isolated suction. The B RHR pump was manually tripped. There were no adverse consequences since the RHR pumps are equipped with a minimum flow recirc. line. Also, 8702B was reopened and the RHR pump restarted within one minute.	The associated surveillance test procedure (STP-340.C08) did not adequately address the concern that the test would definitely cause closure of the RHR suction isolation valves.	The corrective action taken is the revision of STP-340. 008 to line up alternate RHR train with its associated suction isolation valve locked out.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Sequoyah-1 327-82116 820916	Mode 5	Both trains of the Residual Heat Removal System were declared inoperable due to the inadvertent closing of RHR suction valve 1-FCV-74-2.	During modifications on Train B of the Solid State Protection System (SSPS), the power fuses were removed to allow work on the output relays. This caused valve 1-FCV-74-2 to close rendering the RHR system inoperable. Immediate operator action was initiated to stop the RHR pump and the valve was reopened using auxiliary power. The pump was restarted and the system returned to service six minutes later.	None.
Calvert Cliffs-2 318-82053 821122	Mode 6	While deenergizing instrument power supply panel 2V02, shutdown cooling flow was lost. A shutdown cooling return valve, 2-SI-652, shut when this panel was deenergized due to an incorrectly installed temporary jumper meant to prevent 2-SI-652 closure. Shutdown cooling flow was restored four minutes later.	The technician assigned to determine the electrical line up required failed to clarify the exact power supply being deenergized. this resulted in an incorrect temporary jumper location. also, technician did not clearly describe the power supply on the Line Up Document.	The technician was re-instructed on the requirements related to temporary line ups.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
North Anna-1 338-83003 830122	Mode 6	RHR flow was lost for approximately four minutes.	This event initiated when the 15KVA inverter to AC Vital Buss 1-III failed, thereby deenergizing an auxiliary relay for pressure channel P-1403 (used for logic to close RHR suction valve). The deenergizing of the relay cause the RHR suction Valve to close.	Vital Bus 1-III was restored and the RHR suction valve reopened and RHR flow restored.
St. Lucie-1 335-83021 830329	Shutdown for refueling, with refueling cavity filled greater than 23 feet.	Two out of four shutdown cooling hot leg suction valves closed isolating all flow to the core. The valves were reopened in approximately 10 minutes and shutdown cooling flow reestablished.	The shutdown cooling hot leg suction valves closed when construction personnel working in the rear of RTGB 104 shorted out the power supply to one of the control grade pressure indicatior control circuits which gave a close signal to the valves.	Power was restored and the circuit returned to normal.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
North Anna-2 339-83023 830414	Mode 6	The Residual Heat Removal (RHR) Flow was temporarily lost (<1 minute) when one of two in series RHR suction valves closed. Flow was promptly restored.	This event was initiated when the input breaker to the 20 KVA inverter to vital Bus 2-I was inadvertently opened. This action de-energized an auxiliary really for pressure channel P-2403 and caused MOV-2700 (RHR suct on valve to close).	Upon realizing his mistake, the operator reclosed the breaker and restored 2-I Vital Bus. The RHR suction valve was reopened and RHR flow restored.
North Anna-2 339-83036 830429	Mode 6	One of two source range channels (N-31) and the Containment Particulate and Gaseous Radiation monitors (MR-259 & 26)) were de-energized. The vital bus was promptly reenergized and the deenergized equipment promptly restored.	This event occurred as maintenance personnel were performing a ground isolation procedure for 125 volt DC Bus 2-I and shorted the test leads as loads were being transferred to another DC bus. This event cause the input breaker to 2-I 120 volt AC vital Bus to open and deenergized the above listed equipment.	The vital bus and deenergized equipment were restored and normal operation resumed.
Salem-2 311-83024 830514	Modes 4/5	On two separate occasions on May 14 & 15 1983, a Residual Heat Removal system suction valve was observed to have closed, thus eliminating flow in the operating RHR loop. In each instance, the operating pump was stopped and Action Statement 3.4.1.4B was entered. No reduction in reactor coolant system boron centration occured with an RHR loop out of service. A loop was immediately restored to service.	Investigation in the first case revealed that the No. 2B Vital Instrument Bus had been deenergized for maintenance causing the RHR suction valve to close. In the second case, Comparator 2PC-405A-B apparently failed causing the valve to close.	Personnel were counseled concerning the first incident and the comparator was replaced.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Turkey Point-3 250-83019 831008	Mode 6	While performing a hydrostatic test on Unit 3, a hot leg sample line, pressure transmitter (PT-3-405) was exposed to a hydrostatic test pressure of approximately 3100 psig. This activated the interlock between PT-3-405 and MOV-3-751 (Residual Heat Removal, return from Loop C Hot Leg) thus isolating RHR flow for approximately 6 minutes. Unit 3 was at refueling, shutdown with the reactor coolant system drained at the time of this event.	The root cause was determined to be an unclear drawing configuration of the loop A sample line. This led personnel performing the hydro test to believe that there was double isolation between the ISI test boundary and instrumentation coming off the sample line.	None listed.
Calvert Cliffs-1 317-83061 831012	Mode 6	The shutdown cooling (SDC) return isolation valves were shut terminating SDC (TS 3.9.8.2) Investigation revealed that PIC-103 which senses RCS pressure in order to shut the SDC return valves on increasing RCS pressure had not been deactivated prior to a hydro on the instrument sensing lines. Increasing hydro pressure resulted in initiation of a signal to shut the valves. The test was terminated and SDC restored at 2020.	An inadequate electrical isolation of pressure transmitters resulted in an inadvertent actuation of shutdown cooling isolation during a pressure test of transmitter tubing.	Procedural changes will require a review of transmitter electrical process functions prior to pressure testing.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Diablo Canyon-1 275-84004 831027	Modes 4/5/6	Prior to fuel load on 9/29/81 & again on 10/27/83, inadvertent reactor coolant system residual heat removal pump suction valve closures occurred. In both cases, a RHR pump continued to operate following the valve closure. In 1981, a pump ran for about 5 minutes with no damage. In 1983, RHR pump seal damage and a slightly bowed shaft occurred after one hour's operation. In 1981, the cause of valve closure was the deenergization of the analog and/or logic channel. As a corrective action for this event, operating procedures were modified to require power to be removed from the valve motors except when the valve was being operated.	The cause of valve closure was testing performed on the analog channel combined with inadequate surveillance test procedures which left power applied to the motors following surveillance testing.	These procedures have also been modified as corrective action. This licensee event report is submitted for information purposes because of its potential generic interest. Had the event occurred in 1984, it would have been reportable under 10 CFR 50.73(a)(2)(v) and (vii).
Summer 395-83136 831112	Mode 5	An Engineered Safety Feature (ESF) 120 VAC vital instrumentation panel, APN-5901, was transferred to alternate power to accommodate modifications to its normal power source. With Train A Residual Heat Removal System in service, its suction valve, XVG-8701A closed. The valve	A dead bus transfer from normal to alternate power source created a power transient in the associated ESF instrumentation bus. Erroneous signals were generated as a result of the transient. Conditions were returned to normal after the transfer was completed.	A power distribution list is to be generated to inform operators of plant instrumentation power sources.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERA[illegible] [illegible]IDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Summer (continued) 395-83136 8[illegible]0629		was reopened within approximately five minutes. No adverse consequences resulted due to plant conditions and the short duration of the event.		
Salem-2 311-83062 831128	Mode 5	During a maintenance shutdown, 2A vital instrument bus was transferred to its alternate power supply to perform routine meter calibrations on 2A inverter. A voltage transient caused 2RH2 to shut resulting in a loss of RHR flow. The valve was immediately reopened and RHR flow was re-established.	This evolution caused a voltage transient which effects certain equipment.	This equipment will be identified and procedures will be revised to reflect equipment to be monitored and appropriate actions to be taken.
Salem-2 311-83066 831220	Mode 5	During a maintenance shutdown, 2RH1 closed, resulting in a loss of RHR flow. The event took place during the tranefer of 2B4KV vital bus from one station power transformer to the other. The backup power supply for 2B instrument inverter was deenergized for maintenance. The transfer resulted in a momentary loss of the instrument bus; 2RH1 closed on interlock.	When 2RH1 closed, the operator secured 22 RHR pump. The cause was determined and 2RH1 was reopened. 22 RHR pump was started and RHR flow was reestablished within 22 minutes of the occurrence.	The incident was addressed in an Operations Department newsletter.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
McGuire-2 370-84002 840115	Mode 5 with RCS loops not filled.	During filling and venting operations for Unit 2, Start up operators closed the breakers for valves 2ND-1B and 2ND-2A (C reactor coolant (NC) loop to Residual Heat Removal (ND) pumps isolation valves) on January 15, 1984. Fuses for the A and B Train output relay cabinets of the Solid State Protection System (SSPS) had been removed on January 9 to permit transmitter time response testing. Normally closed contacts in the close circuits of the valves are controlled by SSPS output relays. With SSPS outputs deenergized, the contacts completed the circuits providing close signals for 2ND-1B and 2A. Thus, when the breakers for 2ND-1B and 2A were closed, the valves immediately closed, isolating ND suction. Both ND trains were declared inoperable at 2207, pursuant to Tech. Spec. 3.4.1.4.2. Unit 2 was in Mode 5 with the Reactor Coolant loops not filled at the time of the incident. Operators responded by tripping ND pump A and chemical and volume control (NV) pump and reopening the breakers for 2ND-1B and 2A. The valves were then manually opened and ND Pump A was restarted.	This incident is attributed to personnel error. Appropriate measures to ensure control over 2ND-1B and 2A were not taken on January 9, 1984, when the SSPS output relay cabinets were deenergized.	Procedures were revised and appropriate personnel will be counseled.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Salem-2 311-84002 840209	Mode 5	During a maintenance shutdown, residual heat removal common suction valve (2RH1) indavertently shut while testing was being performed on the pressurizer overpressure protection system. This resulted in a loss of RHR flow through the reactor coolant system.	The breakers for the RHR common suction valves were not tagged as required prior to Pops testing. The controls for these valves located on the control room console contained red bezel covers which indicated that the valves already contained shift supervisor tags. Unknown to the shift supervisor, these tags has been temporarily released and the red bezel covers had not been removed. Technical Specifications allow RHR to be removed from service for up to two hours, provided there are no operations which would result in a reduction of reactor coolant system boron concentration. RHR flow was reestablished within seventeen minutes.	A system will be established for updating the status of the Control Room console bezel covers whenever tagging releases or requests are initiated.
Palisades 255-84007 840622	Mode 5	On June 22, 1984, with the plant in cold shutdown, work on a pressure indicator inadvertently caused a number of spurious actuations of the Low Temperature Overpressure Protection System (LTOP). No actual PCS pressure transient occurred.	None.	The importance of communicating the potential to initiate suprious signals during work on associated instruments will be emphasized to the appropriate personnel.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Summer 395-84044 841002	Mode 5	With Train B of the Residual Heat Removal (RHR) system in service, an instrument and and control (I&C) technician removed two (2) fuses in Solid State Protection System (SSPS) Cabinet XPN-7020 for personnel safety during implementation of a modification. The fuses were immediately replaced when the technician heard a relay activate. The deenergized circuit caused the Train A RHR suction isolation valves XVG-8702 A and B (one valve in each RHR train) to close. Operations personnel immediately restored Train B RHR to service after the valve closure.	The cause was determined to be drawing errors.	To prevent a potential recurrence, the licensee initiated a drawing revision and replaced the defective fuse holder on October 9 and October 10, 1984, respectively.
Summer 395-84045 841018	Mode 5	On October 18, 1984, outage with Train A of the Residual Heat Removal (RHR) System in service, RHR Train B out of service for routine maintenance, and the reactor coolant system (RCS) vented at a temperature of approximately 110°F. At 1605 hours, a power loss to 120 VAC distribution panel APN-5901 deenergized Solid State Protection System (SSPS) Channel 1 and caused the instrument panel for RCS wide range pressure (PT-403) to initiate valve XVG-8701A.	Following determination that the power loss had been caused by personnel error during the performance of a plant modification, Operations personnel restored power to APN-5901. XVG-8701 was opened and Train A of the RHR system returned to operable status at 1630 hours (total time of RHR isolation was approximately 25 minutes).	None.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Turkey Point-4 251-84027 841130	Mode 6	The Residual Heat Removal (RHR) System flow was interrupted for approximately 4 minutes. Upon actuation of the OMS controlling in the low pressure setting (415 psig), power operated relief valves (PORVs) PCV-456 and PCV-455C cycled open to relieve RCS pressure thus performing their intended function. Immediate corrective actions included the following: 1) the B RHR pump was stopped, 2) the operating charging pump was stopped and pressure was controlled by pressure control valve PCV-145, 3) MOV-4-751 was successfully opened by bypassing the present closing signal and racking open its breaker, 4) the B RHR was then restarted, 5) Instrumentation and Control (I&C) replaced PC-405B and released it to Operations. The respective breaker for MOV-4-751 was racked in.	The root cause s emmed from the closure of MOV-4-751 isolation valve in the RHR pump suction line caused by a malfunction in pressure controller PC-405B failing by producing a false indication of high reactor coolant system (RCS) pressure, thus activating the protective interlock.	None.
Diablo Canyon-1 275-85005 850120	Mode 5	Both Residual Heat Removal (RHR) trains became inoperable for approximately 6 minutes. When overpressure protection channel PT-403	This event was caused by a plant technician checking the wrong breaker and verifying it as being open.	An Incident Review Board met and made recommendations to revise Surveillance Test Procedures (STPS) I-68A and I-69A. The procedures will

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Diablo Canyon-1 275-85005 850120 (continued)	Mode 5	was removed from service, an interlock between the protection channel and RHR pump inlet valve, MOV-8702, resulted in valve closure and both RHR pumps losing suction. The pumps were manually tripped in response to the RHR Low Flow Alarm. At 2309, MOV-8702 was reopened. At 2312, RHR pump 1-1 was restarted and RHR flow established. All Tech. Spec. action statements were met.		inform the technician that the breaker maybe found open or closed and, if found closed, Operations Dept. should be notified to open it. Also, the event was reviewed with all affected personnel stressing the importance of verifying the correct breaker.
Diablo Canyon-1 275-85006 850125	Mode 5	A loss of vital 4KV bus voltage resulted in the autostarts of diesel generator (DG) 1-2, Containment Fan Cooler System 1-5, and Auxiliary Saltwater pump 1-2. In addition, for approximately 2 minutes, the Decay Heat Removal Capability was lost when the closure of the loop 4 RHR suction valve (MOV-8702) resulted in both Residual Heat Removal (RHR) trains being isolated from the Reactor Coolant System. The RHR suction valve was subsequently opened and RHR flow established. Within two minutes all other affected equipment and systems were returned to their normal standby conditions.	Investigation has shown that the cause of this event was misadjustment of the auxiliary switches in the Bus G feeder breakers (HG 13 and 14). The auxiliary switches were adjusted to a new tolerance and the breakers were tested with satisfactory results.	To prevent recurrence, procedure E-51.2, 4.16 KV Circuit Breaker PM (Preventive Maintenance) is being revised to identify the specific auxiliary switch adjustment required for the bus feeder breakers.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Farley-1 348-85008 850506	Mode 5	At 0925 on 5/6/85, both trains of the Residual Heat Removal System (RHR) and the Overpressure Mitigation System (OMS) were made inoperable by a common cause. At 0920 on 5/6/85, the suction valve for the A train RHR system closed. Attempts to open the valve from the main control board were unsuccessful and the operators stopped the A train RHR pump. Similarly, the suction valve for the B train RHR system closed. Attempts to opend this valve from the main control board were unsuccessful and the operators stopped the B train RHR pump at 0925. Closing of these valves also isolated the OMS relief valves. Power was removed from the two valves and they were manually opened allowing the A train RHR pump to be restarted at 1012 on 5/6/85 and the B train RHR pump to be restarted at 1020. This restored both trains of RHR and OMS to operability.	This event was caused by procedural inadequacy and personnel error. Power which had been procedurally removed from the valves was incorrectly restored while an autoclose signal from the RCS Pressure Transmitters was present.	None.
Sequoyah-1 327-85020 850514	Mode 5	Both trains of Residual Heat Removal (RHR) were inadvertently isolated by closure of the Train B suction valve. The suction was reestablished	Reactor Coolant System wide range pressure transmitters 1-PT-68-66, which is used for RHR overpressure protection, receives its process signal from the RVLIS Sense Lines	None.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Sequoyah-1 327-85020 850514 (continued)	Mode 5	within approximately 16 minutes and there was no indicated change in RCS temperature. The isolation occurred while work was being performed on the Reactor Vessel Level Instrument System (RVLIS) to refill sense lines.	and was increased to approximately 2000 psi during testing (RHR isolation is at 700 psi increasing).	
Cook-1 315-85046 850907	Mode 5	Power was lost to the Control Room instrument bus distribution circuits for channel 3 and channel 4. This resulted in various ESF reactor trip signals and loss of the residual heat removal pumps. Channel 3 and 4 circuits were being powered by an alternate source while the normal power source was out of service.	The circuit breaker for channel 3 tripped as a result of an inadequately terminated lead. A licensed operator investigating the power loss thought the channel 4 circuit breaker had tripped also. The operator then attempted to reset the breakers by opening then closing the breaker. This resulted in the channel 4 breaker being momentarily de-energized. This caused various ESF reactor trip signals and the loss of residual heat removal pumps (due to the refueling water storage tank level indication reading low from power loss). This placed the unit in a limiting condition for operation per Tech. Spec. 3.4.1.3. The	To prevent recurrence, the operator has been counseled not to take immediate actions where the situation does not require it.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Cook-1 315-85046 850907 (continued)	Mode 5		Residual Heat Removal System was made operable within 2 minutes after loss. No ECCS actuation occurred and Channel 3 instrument circuit was restored at 0835 hours.	
Turkey Point-3 250-85036 851025	Mode 5	The Residual Heat Removal (RHR) System flow was interrupted for approximately 27 minutes due to the automatic closure of MOV-3-750. This valve is located in the single RHR pump suction line originating from the hot leg of the Reactor Coolant System (RCS) and it is designed to close to protect the RHR system from overpressurization when the RCS pressure exceeds 465 psig. RHR was re-established approximately 27 minutes later by opening the valve and removing power to the valve's motor operator. During the period in which the valve remained closed, the RCS temperature rose 20°F, i.e. from 110°F to 130°F. MOV-3-750 was returned to service and performed satisfactorily after replacing a malfunctioning relay.	A failed relay, PC-403-A-2, in the pressure comparator for the pressure controller PC-403 caused two blown fuses in the comparator which resulted in an erroneous high pressure signal closing RHR valve MOV-3-750.	Immediate corrective actions were taken as follows: 1) the 3B RHR pump was stopped when MOV-3-750 closed. 2) MOV-3-750 was manually opened and its power removed by racking open its breaker. 3) RHR pump 3B was then restarted. 4) Failed relay PC-403-A-2 was replaced along with two blown fuses and MOV-3-750 was restored to service after verification of operability.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Zion-2 304-86001 860103	Mode 5	A momentary fluctuation of output of inverter power supply Bus 213 (cause unknown) caused the charging flow control valve, 2VC-FCV121, to fail to the 20% demand position and also caused 2MOV-RH8701, the RHR pump suction isolation valve to fail closed. This increased charging flow from 39 to 190 gpm and isolated letdown flow resulting in lifting of the pressurizer power operated relief valves (PORVs). While investigating the cause, Bus 213 was again deenergized and the PORVs again lifted.	The cause of the bus output fluctuation is currently unknown.	None.
Diablo Canyon-2 323-86002 86-0117	Mode 5	At 0455 PST on 1/17/86, while attempting to transfer instrument AC Panel PY 2-1A from normal to backup power supply, an unlicensed operator went to the wrong panel and inadvertently transferred instrument AC Panel PY 2-1 to its backup power source. This momentary loss of power caused relay actuation which resulted in the closure of Residual Heat Removal (RHR) valve 8702.	In response to the ensuing loss of flow alarm, RHR Pump 2-1 was secured by a licensed operator. RHR Valve 8702 was reopened from the Control Room. RHR Pump 2-1 was restarted, observed for seal damage, and declared operable at 0508 PST, January 17, 1986.	To prevent recurrence, the operator involved has been counseled, operating procedures on transferring instrument AC panel power supplies will be revised, and panel identification labels in the instrument AC panels will be upgraded.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Turkey Point-4 251-86006 860315	Mode 6	Work was progressing to de-energize and replace a vital bus feeder breaker, 4P08. When breaker 4P08-3 was opened, the RHR pump suction valve went closed. Upon receipt of the letdown, isolation alarm, the RHR pump was stopped, the breaker re-energized, the valve re-opened, the pump restarted, and flow restored in approximately 5 minutes.	The wiring diagrams were reviewed in advance of the work to identify and compensate for any undesirable change of state that might be triggered; however, the two responses discussed above were not identified.	Each procedure on loss of vital bus panels (4) contains a summary of the important functions that will be lost in Modes 1, 2, and 3. Summaries of lost functions in Modes 4, 5, and 6 will be added.
Catawba-1 413-86044-1 860815	Mode 5	Technicians were replacing a relay in the train A Solid State Protection System (SSPS) cabinet when a lug on the relay shorted to cabinet ground and caused the output relay fuse in the SSPS cabinet to blow. When the fuse blew, power was lost to the relays that control the position of the A and B train suction valves for the Residual Heat Removal (ND) pumps. Subsequently, these relays changed state and the valves closed. The ND system was inoperable for approximately 15 minutes before a new fuse was installed in the SSPS cabinet. The unit was in Mode 5 cold shutdown, at the time of this incident.	This incident is assigned cause Code A, personnel error. While inserting a relay mounting screw, the technician's hand slipped, causing a short and blowing a fuse in the 120 VAC power supply of the SSPS output bay.	None.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Diablo Canyon-1 275-86012 860908	Mode 5	An Instrumentation and Controls (I&C) technician inadvertently grounded a power supply while installing a modification in a Solid State Protection System (SSPS) cabinet. The momentary grounding of the power supply caused relay actuation which resulted in the closure of Residual Heat Removal (RHR) valve 8702 and an RHR low flow alarm. In response to the RHR low flow alarm, the operating RHR pump was secured by a licensed operator. RHR valve 8702 was reopened from the Control Room. The RHR pump was restarted at 2316 PDT and no seal damage was observed.	Technician grounded a power supply while installing a modification to the SSPS.	The event was reviewed at an I&C meeting, emphasizing attention to energized and potentially energized circircuits when working on electrical components. The circumstances and lessons learned from the event will be evaluated for possible inclusion in the Generic New Employee Training Program for I&C personnel. Additional training on 10 CFR 50.72 Reporting Requirements will be provided for all applicable personnel.
Rancho Seco-1 312-86024 861115	Mode 5	The plant was in cold shutdown, removing decay heat via the Decay Heat Removal System (DHS), Train A, on Novemer 15, 1986. At 1:00 PM, in preparation for a fuse replacement activity in the SIA Bus inverter, SIA bus power was momentarily interrupted, DHS overpressure distables tripped, HV-20001 closed which tripped DHS A Pump as designed. Steps were taken immediately to restore a DHS train to service in accordance with T.S. 3.1.1.5.	The basic cause of the inverter failure is that the original design did not allow for testability of the device through the use of a substitute power source.	That design deficiency, identified as early as 1979 (NCR S-1258, Rev. 2), was recognized by the current action plan for performance improvement. There is a preventive maintenance procedure, EM.171A, Station Inverter Routine - Static Products Inverters, that is scheduled to be performed once per year on the inverters. A 120VAC vital bus system improvement was approved, but has not been implemented yet.

TABLE A-1: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Rancho Seco-1 312-86030 861208	Mode 5	The plant was in cold shutdown removing decay heat via the Decay Heat Removal System (DHS) Train B on December 8, 1986. Startup transformer #1 was scheduled for routine preventive maintenance. A loss of the 4A bus power attendant diesel generator start and decay heat system (DHS) isolation occurred during the transfer of the source transformer at 2:18 PM on December 8, 1986.	An automatic feature of the Nuclear Service Bus is a five second limit on having two sources feeding the bus. The Control Room operator closed startup transformer #2 supply breaker 4A10 onto the 4A bus. When the operator opened the supply breaker (4A01) from startup transformer #1, breaker 4A10 from startup transformer #2 had just completed the automatic five second run-out and had tripped open. These events left the 4A bus without either the normal or alternate supply. An attendant result was that when power was restored, DHS suction valve HV 20001 closed as would be expected in this situation causing the DHS isolation.	The power supplies to both HV-20001 and HV-20002 are currently racked out. The purpose for the DHS system valve interlocks is to prevent overpressurizing the DHS piping with RCS pressure. Since the RCS is open to atmosphere, there is no need for the interlocks to protect the DHS piping from overpressure.

TABLE A-2: AC... LOSSES OR DE...ADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW – RCS INVENTORY R..UCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
McGuire-1 369-82024 820302	Mode 5 – Draining the Reactor Coolant System for Steam Generator Inspection Investigation	A Residual Heat Removal (ND) pump low discharge alarm resulted in ND Pump 1A being stopped due to signs of cavitation. With the redundant Pump 1B out of service for maintenance, no means existed for core residual.	A misapplication of the control board level guage led to inaccurate indication of the Recator Coolant (NC) system water level. NC level was raised to the minimum level for ND operation and normal ND flow was resumed.	A modification to have the the reference leg of the transmitter connected to the PORV discharge line redundant level indication and an expanded scale in the normal NC level range for ND operation is planned.
North Anna-2 339-82026 820529	Mode 5 – Draining the RCS	The suction to the Residual Heat Removal System (RHR) pumps from the Reactor Coolant System (RCS) was lost on three occasions; once for 8 minutes, once for 26 minutes, and once for 1 hour.	Suction to the RHR pumps was lost due to erroneous RCS level indications while draining the RCS. The actual RCS level was lower than observed.	In each case, a charging pump was started to refill the RCS and to allow further RHR pump operation.
North Anna-2 339-82049 820717	Mode 5 – RCS Drained to Centerline of the Nozzles	On July 30, 1982, suction was lost to "A" and "B" RHR pumps. On August 2, 1982, RHR flow was less than 3000 GPM and pump amps were fluctuating prior to taking corrective action.	Each of these events appears to have been caused by a slow decrease in RCS level in conjunction with the vortex action at the pump suction. This action led to an induction of air into the RHR pump casing.	Corrective action included closure of the RHR discharge to the RCS, the venting of pump casings, and the addition of water to the RCS until RHR flow was restored.
North Anna-1 338-82067 821019	Mode 6 – and Drained to Centerline of the Nozzles	On October 19, 1982, suction to the A and B Residual Heat Removal System (RHR) pumps was lost for about 36 minutes. On October 20, 1982, A and B (RHR) pump suction was lost for 33 minutes.	Suction to the RHR pump was lost because of ambiguous Reactor Coolant System (RCS) level indication while drained to centerline of the nozzles. The actual RCS level was lower than observed.	Corrective actions in each case consisted of adding water to the RCS until an RHR pump could be started and proper RHR flow restored

TABLE A-2: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - RCS INVENTORY REDUCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
McGuire-1 369-83017 830405	In Mode 6 while the refueling cavity was being drained so that the Reactor Vessel Head could be placed in position.	The Residual Heat Removal (ND) Pumps began to cavitate and eventually both the pumps were stopped.	The Reactor vessel level gauge being used to provide an indication that the level was approaching the vessel flange level had been isolated (Reactor Coolant Drain Tank Isolation valve had been closed during an attempt to reduce leakage into the RCDT). Additionally, procedures did not require visual monitoring of cavity level. The cavity refilled, the ND system vented and declared operable.	Procedures will be revised and personnel counseled.
Ginna 244-83015 830412	Mode 6 in preparation for the A Steam Generator Channel Head Decontamination, Temporary hot and cold leg nozzle isolation devices were being utilized for future containment of the dilute	Prior to the dilute chemical addition, a small amount of water was being used in the channel head in conjunction with air pressure at 30 psig to properly seat the dams to minimize leakage past the dams into RCS. During this process, water drained completely through the leaky dam in the cold leg nozzle, thus allowing air to pass through, resulting in an air bubble formation passing through the RCS and entraining the RHR pump suction thus causing loss	The event occurred because the A S/G temporary cold leg nozzle isolation device leaked, thus allowing air to enter the RCS and to the RHR suction line. Upon seeing RCS loop level changes and loss of RHR flow indicating air entrainment.	The RCS water inventory was immediately increased by usage of the refueling water storage tank via MOV-856 valve. Steps were taken by the Control Room operator to manually trip the running RHR pump to prevent damage to the pump. The RHR loop was properly vented and RHR was returned to service approximately 12 minutes after it was lost.

TABLE A-2: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - RCS INVENTORY REDUCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Ginna (continued)	chemical solution within the channel head areas.	of RHR located on the hot leg of the same loop. The RHR pump in operation at the time was manually tripped by the Control Room operator to prevent damage to the pump. Prior to this event, the RCS Boron concentration had been borated to greater than 2400 ppm (2000 ppm required for refueling shutdown mode).		
North Anna-2 339-83038 830503	Mode 6	On May 3, 1983, suction to the B Residual Heat Removal (RHR) [illegible] was lost while transferring water from the Reactor Coolant System (RCS) to the refueling water storage tank (RWST) via the Refueling Purification (RP) System. The A Pump was secured and the B RHR Pump started but suction was not available.	Suction to the RHR pump was lost because the RCS was pumped below the established operating limit. Pumping of the RCS continued without adequate monitoring of the RCS level.	The RCS was refilled and RHR pump suction was restored. The responsible senior operator was reinstructed.
Surry-1 280-83024 830517	Mode 5	The B RHR pump was removed from service on two occasions due to cavitation. This resulted in less than two operable RHR loops and no loops in operation.	An inaccurate standpipe level indication resulted in the cavitation of B RHR pump. RCS level was increased, RHR pump vented and returned to service.	Adjustments were made to the standpipe indicator.

TABLE A-2: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - RCS INVENTORY REDUCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Sequoyah-2 328-83101 830806	Mode 6	At 0838 (C) during pump down of the refueling cavity to perform maintenance on the Loop 4 Reactor Coolant System Cold Leg Nozzle Inspection Plate, the B Train Residual Heat Removal Pump began to cavitate.	The cause of the pump cavitation has been attributed to loss of suction head due to RCS water level being pumped below the center line of the loop 4 RCS Hot Leg. False indications in Tygon level tube apparently due to a flow restriction and possible contribution from an excessive pump down rate through 2-HCV-74-34 to the RWST allowed the level to be pumped below the nozzle.	None.
McGuire-2 370-83092 831231	Mode 5 - During draining operations of the Reactor Coolant System	Residual Heat Removal (ND) Pump B was observed to have zero discharge flow and was subsequently tripped and ND Train B declared inoperable.	This is attributed to procedural deficiencies due to inadequate guidelines regarding the water level to be maintained in the Reactor Coolant (NC) Loops during ND operation. The Fueling Water Storage Tank to ND Pump Isolation Valve was cycled to provide core cooling and raise NC system level until flow was restored.	Procedures will be revised by March 31, 1984. Additional corrective actions are detailed in LER 370/84-01.
Trojan 344-84010-1 840504	Mode 5	During an RCS drain down to support refueling operations at 1650 on May 4, 1984, Residual Heat Removal (RHR) Cooling could not be reinitiated for a total of 40 minutes due to air entrainment in the suction	The cause of RHR Pump Air entrainment was vortexing due to RCS level being low. The low RCS level was caused by a partial crud blockage in the lower drain line tap of the temporary	Redundant level indication stand pipes from two RCS loops will be installed for future refueling drain down evolutions.

TABLE A-2: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - AUTOMATIC RHRS SUCTION VALVE CLOSURE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Trojan (continued)		of the A RHR pump. Both RHR pumps had been stopped for ten minutes for annual ESF actuation response time testing. An additional 30 minutes were required to restore sufficient RCS water inventory to restart an RHR pump. The B RHR pump was then started and the RCS temperature rise was terminated. The highest indicated RCS hot leg temperature reached about 201°F.	RCS level indication system. The actual RCS level was lower than the indicated level because of this blockage. (Forced oxidation had been initiated to remove crud from the RCS in preparation for the refueling outage several days before this event). The RCS level was increased via emergency boration and Refueling Water Storage Tank (RWST) fill. High pressure was applied to remove the crud blockage and reestablish accurate RCS level indication.	
Cook-2 316-84014 840521	Mode 5	With the Reactor Coolant System at half-loop, the Control Room operators started a second residual heat removal (RHR) pump in preparation for removing the operating RHR pump from service. With both pumps running, flow became excessive for the half loop condition causing cavitation and air binding of both pumps. Both pumps were out of service for approximately 25 minutes while they were being vented which is within the one hour.	Operation of two (2) RHR pumps while in a half loop condition caused vortexing to both RHR pumps.	To prevent recurrence, the procedure which controls the operation of RHR pumps has been changed to include specific instructions to stop the operating pump prior to starting the second pump.

TABLE A-2: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - RCS INVENTORY REDUCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Zion-1 295-84031-1 840914	Mode 5	While in cold shutdown, draining the RCS in preparation for steam generator primary-secondary leak testing, the RCS level dropped below the suction line for the RHR pump.	This was the result of an improper valve lineup which gave false indication of the RCS level.	Station procedures will be revised to prohibit simultaneous draining and purging operations. A procedure for loss of RHR will be prepared Retraining will be conducted in proper valve lineup procedures.
McGuire-2 370-84001 840109	Mode 5	During draing operations of the Reactor Coolant (NC) System Residual Heat Removal (ND) Pump B was observed to have zero discharge flow. Pump B motor amperage was low and the ND system pressure and Pump B discharge pressure were equal. Based on these factors, ND Pump B was tripped and ND train B was declared inoperable at 1650. The FWST to ND Pump Isolation valve was twice cycled to provide core cooling and raise NC System leve with water from the Fueling Water Storage Tank while venting the ND suction line and pump B. The core temperature rate of rise decreased after the first water addition, and the second addition resulted in slightly decreased core temperatures. ND pump B was restarted	These incidents are attributed to procedural deficiencies due to inadequate guidelines regarding the water level to be maintained in the Reactor Coolant loops during ND operation.	None.

TABLE A-2: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - RCS INVENTORY REDUCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
McGuire-2 (continued)		at 1720 and flow was restored. On January 9, 1984, operators were again decreasing level in the Reactor coolant loops when a computer alarm for low ND Pump A discharge pressure was received. Fluctuations in ND Pump A motor amperage were noted and simultaneous fluctuations in discharge pressure and flow also occurred. After the low ND Flow annunciator alarmed, ND Pump A was tripped at 1246 and ND Train A was therefore inoperable. Operators manually opened the ND system to FWST isolation valve, raising the Reactor Coolant Loop level with water from the FWST. The suction line and pump were vented and the pump was restarted at 1348.		
North Anna-2 339-84008-1 841016	Mode 5	A complete loss of Residual Heat Removal (RHR) capability occurred when both RHR pumps were unable to operate due to the introduction of air into the RHR system. The incident occurred during the drain down of the Reactor Coolant System (RCS) when the level of the RCS was being monitored via a standpipe off the centerline of one of the RCS loops.	The isolation valve to which the standpipe was attached became clogged sometime during the drain down and falsely indicated 64 inches above centerline when in fact the level was below the RHR suction line (below centerline). Subsequently, letdown from the RCS was isolated and makeup initiated. RHR capability was regained 2 hours after initiation of the event.	RCS level indication was moved to an alternate tap off loop centerline and indicated satisfactorily.

TABLE A-2: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - RCS INVENTORY REDUCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Catawba-1 413-85028 850422	Mode 5	Both trains of Residual Heat Removal (ND) were inoperable. This was the result of ND Train A being declared inoperable on April 20, 1985, at 1600 hours for the performance of various ND Train A related work requests and ND Pump B being secured on April 22, 1985, at 2039:21 hours due to loss of pump suction. Also, Tech. Spec. 3.4.1.4.2 was violated on April 22, 1985 at 0522 hours when reactor coolant (NC) system draining began with ND train A inoperable.	False NC system level indication apparently contributed to the loss of ND Pump B suction. However, the cause of the false level indication is not known at this time. With ND Train A inoperable, the limiting conditions for operation of Tech. Spec. 3.4.1.4.2 were not met. However, prior to beginning NC system draining, a decision had been made to allow draining to begin with ND Train A inoperable. Therefore, this incident is also classified as a personnel error. After ND Pump B was secured, centrifugal charging pump (CCP) A was aligned to the Refueling Water Storage Tank (FWST) and started to restore NC system level. ND Pump B was then vented and restarted at 2051:17 hours.	None.
Sequoyah-1 327-85040 851009	Mode 5	At 1807 CST during Cold Shutdown, swap over from B Train to A Train Residual Heat Removal (RHR) resulted in both trains becoming inoperable due to air injection into the suction of the pumps. This require both pumps to be vented and required RCS level to be raised from 695 ft., 1 inch to 695 ft., 5 inches to prevent a possible recurrence of the vortex problem. Suction for RHR comes from the Loop 4 hot leg which has centerline of 695 feet, 5 inches.	The cause for the loss of flow can be attributed to the additional suction caused by placing the standby RHR pump in-service coupled with the low RCS level of 695 feet, 1 inch.	System operating instruction (SOI)-74, Residual Heat Removal system is being revised to change the lower RCS operating limit from 695 feet, 0 inches to 695 feet, 6 inches and will require operating pump to be removed from service prior to starting the standby pump.

TABLE A-2: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW - RCS INVENTORY REDUCTIONS LEADING TO LOSS OF RHRS PUMP SUCTION CAUSED BY REACTOR VESSEL INDICATION ERRORS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Zion-2 304-85028 850113	Mode 5	The 2B Residual Heat Removal (RHR) pump became airbound as a result of vortexing. Unit 2 was in cold shutdown (Mode 5) with the reactor head installed but not tensioned and the reactor coolant system (RCS) vented to atmosphere. 2B RHR pump had been in operation providing decay heat removal with RHR letdown in progress and 2B charging pump providing makeup flow to the RCS. Decay heat removal was lost for 75 minutes with an RCS change in temperature of 15°F. The unit had been shutdown for approximately 100 days; therefore the safety significance was minimal.	The root cause of the event was identified to be inadequate procedures coupled with the lack of knowledge of the level at which the RHR pumps begin to cavitate. As a contributing factor, there were problems found with the level indication.	To prevent recurrence, procedures will be reviewed and changed reflecting the lessons learned. Training will be conducted on RCS level measurement and loss of RHR suction. The RCS level system will be modified in order to provide reliable remote level indication during all refueling configurations.

TABLE A-3: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF REACTOR COOLANT INVENTORY VIA THE RHRS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Maine Yankee 309-82013 820324	Mode 5	While making preparations for plant heatup, pressurizer liquid was diverted to the RWST, lowering the level to approximately 800 gallons below low level indication.	Loss of pressurizer level was due to malpositioning of an RHR isolation valve and an RHR recirculation valve. The isolation valve should have been closed prior to opening the recirculation valve. Pressurizer level was normalized using charging pumps taking suction from RWST.	Operations Department will issue a memo to all operators reemphasizing the importance of adherence to plant procedures.
Ginna 244-84003 840307	Mode 5	Draindown of the Reactor Coolant System (RCS) was in progress in preparation for the steam generators (S/G) annual inspection. In the process of draining the RCS to the CVCS Holdup Tanks, while preparing to shift from draining via the Reactor Coolant Drain Tank (RCDT) pump to the low pressure purification pump, valves MOV-851A and B (Containment Sump B suction to RHR) were mistakenly opened prior to shutting the valve, MOV-850A (downstream of MOV-851A and upstream of RCDT pump suction). This resulted in water being drained from the RCS loop to the Sump B with potential loss of RHR capability.	Operator error.	None.

TABLE A-3: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF REACTOR COOLANT INVENTORY VIA THE RHRS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Callaway-1 483-84016 840717	Mode 5 water solid with the RCS at 380 psig and 180°F.	The Reactor Coolant System (RCS) was depressurized to 0 psig and the primary seal on Reactor Coolant Pump C (RCP C) was damaged.	The cause of the RCS pressure transient was determined to be improper sequence of valve operation in the A Residual Heat Removal Pump Surveillance Procedure Restoration. RHR Train B was aligned to take A suction and discharge to the RCS and RHR Train A was being restored from the surveillance during which the suction and discharge were aligned to the Refueling Water Storage Tank (RWST). The procedure rquired opening the Train B RHR injection balance line isolation valve (EJ-HV-8716B) prior to isolating the RHR injection balance line from the RWST by closing BN-8717. Thus the RHR pump was taking suction from the RCS and discharging the RWST which immediately depressurized the RCS. RCP seal damage occurred when the RCS depressurized to 0 psig. The seal was replaced and RCP C returned to service on 8-6-84.	A temporary change notice was issued to correct the RHR surveillance procedure. Similar procedures were also reviewed for impact on plant conditions.

TABLE A-3: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF REACTOR COOLANT INVENTORY VIA THE RHRS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Farley-1 348-86020 861107	Mode 5	A Residual Heat Removal (RHR) loop suction pressure relief valve opened to reduce Reactor Coolant System (RCS) pressure. On 11/7/86, the RCS (in the solid condition) pressure was being increased to 400 psig prior to starting A Reactor Coolant Pump (RCP). The operator increased pressure too rapidly and was unable to stop the increase prior to the 1B RHR loop suction pressure relief valve opening. The opening of the relief valve controlled and reduced the RCS pressure. On 11/15/86, the RCS was being maintained in the solid condition at approximately 400 psig with the 1B and 1C RCPS running. Depending on plant conditions, RCS pressure while solid can either increase or decrease when starting RCP. The operating crew had anticipated a pressure decrease; however, pressure increased when the 1A RCP was started. The operator tried to limit the pressure increase but the 1A RHR loop suction pressure relief valve opened. The opening of the relief valve controlled and reduced RCS pressure.	Operator error.	Operators counseled on controlling pressure increases. Operators made aware that starting a reactor coolant pump can cause a pressure surge in the RCS.

TABLE A-4: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OR DEGRADATION OF FLOW, OR LOSS OF COOLANT INVENTORY DUE TO AUTOMATIC INITIATION OF THE RECIRCULATION MODE OF LOW PRESSURE SAFETY INJECTION, INCLUDING RHRS PUMP TRIPS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
* Zion-1 295-82028 820910	Mode 1	During surveillance conducted at 100% power, RHR miniflow control valve switch 1FIC-610A had failed and would not close the miniflow valve at 1000 gpm as designed. Having the miniflow valve remain open during a LOCA would degrade the pump injection flow by about 10% (450 gpm). Pump was in a degraded mode per T.S. 3.8.2.B.	Microswitch (Barton Model 288) was out of tolerance, because these microswitches are rated for 1500 gpm and during periods of extended shutdown these gauges are subjected to flow rates in excess of 3000 gpm.	A modification has been initiated to replace these microswitches with higher range transmitters. No further report will be issued.
* Zion-1 295-82042 821116	Mode 1	During surveillance conducted at 80%, RHR miniflow control valve switch 1FIC-610A had failed and would not close the miniflow valve at 1000 gpm as designed. Having the miniflow valve open during a LOCA would degrade the pump injection flow by 10% (450 gpm). Therefore, the A RHR pump was in a degraded mode per T.S. 3.8.2.B.	Microswitch (Barton Model 288) was out of tolerance because these microswitches are rated for 1500 gpm and during periods of extended shutdown these gauges are subjected to flow rates in excess of 3000 gpm.	A modification has been initiated to replace these microswitches with higher range transmitters.
* Zion-1 295-83018 830609	Hot or Cold Shutdown	During its monthly surveillance, RHR miniflow control valve switch 1FIC-610A was found failed and would not close the miniflow valve at 1000 gpm as designed. Having the miniflow valve remain open during a LOCA, pump	The microswitch (Barton Model 288) was found to be mechanically inoperable. This switch is rated to 1500 gpm. During periods of unit shutdown, the switch is subjected to a flow rate in excess of 3000 gpm.	A modification is in progress to replace the RHR miniflow microswitches with higher range transmitters.

* not actual failure

TABLE A-4: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OR DEGRADATION OF FLOW, OR LOSS OF COOLANT INVENTORY DUE TO AUTOMATIC INITIATION OF THE RECIRCULATION MODE OF LOW PRESSURE SAFETY INJECTION, INCLUDING RHRS PUMP TRIPS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Zion-1 (continued)		injection flow would be impaired by 10% (450 gpm). Thus the 1A RHR pump was in a degraded mode per T.S. 3.8.3.		

TABLE A-5: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW OR DEGRADED COOLING DUE TO OTHER VALVE CLOSURES, OR EXCESSIVE PUMP/COOLER BYPASS FLOW

[NO EVENTS]

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Rancho Seco-1 312-82012 820505	Mode 5	The A Decay Heat Pump inboard bearing was found to be leaking oil. Since the unit was in cold shutdown, the only consequence was the changing over to the B Decay Heat pump.	The cause of the oil leak has not yet been determined. A follow-up will be written when the cause is determined.	Corrective action will be to repair the leak. The most probable cause is a partial seal failure.
Beaver Valley-1 334-82018 820512	Mode 5	An attempt to start RHR pump (RH-P-1B) failed due to a circuit breaker racking mechanism problem. Immediately prior to this attempt, the power to the bus supplying the operating RHR pump (RH-P-1A) had been removed in accordance with procedure TOP 82-27. This resulted in an interruption of RHR flow lasting 2 minutes.	The initial interruption of flow was caused by both procedural and personnel errors. The TOP was revised and operator training was conducted. The racking mechanism problem which delayed restoring flow was corrected by cycling the breaker, insuring that it was in its fully connected position.	A racking mechanism inspection will be added to the preventative maintenance program.
North Anna-1 338-82063 820614	Mode 5	On 6/14/82, only one of the coolant loops listed in T.S. 3.4.1.3 was operable due to the failure of the Residual Heat Removal Subsystem B Pump (1-RH-P-1B).	The cause of the event was the failure of the Residual Heat Removal Pump 1B.	The impeller motor with integral pump shaft and mechanical seal were replaced and the subsystem returned to service.
Rancho Seco-1 312-82015 820624	Modes 4/5	During a preventive maintenance procedure on the B inverter, there was a momentary loss of power to the B bus. This in turn	The loss of power to the B bus resulted when technicians attempted to parallel the B inverter to a temporary test power	Procedures will be rewritten to enhance communication between maintenance and operations personnel.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Rancho Seco-1 (continued)		caused a short duration loss of DHRS. The core temperature remained unaffected by this loss of flow and the A system was available on standby.	source being used to energize the bus while maintenance was being performed.	
North Anna-2 339-82050 820816	Mode 5	The 1A Residual Heat Removal (RHR) pump was removed from service thereby leaving operable only one loop for decay heat removal since the 1B RHR pump remained available to ensure decay heat removal.	The A RHR pump was removed from service to replace a mechanical seal. The seal primary "O" ring had apparently been overheated.	The seal was replaced, pump operability verified, and the pump restored t/ service. An Engineering Study has been initiated to determin the cause of the seal problems.
Cook-2 316-82109 821209	Mode 6	The west RHR was in service supplying core cooling at 3000 gpm. A reactor coolant high level alarm was received and investigation of equipment showed that the west RHR pump breaker had tripped.	Investigation of activities and a check of the breaker was performed. No reason for the breaker trip-ing could be determined.	The west RHR pump was restarted wi-hin 5 minutes and continued operating without any further problems.
Salem-1 272-82089 821213	Mode 6	At 0750 hours, 12/13/82, due to excessive leakage from the mechanical seal, No. 12 Residual Heat Removal (RHR) pump was declared inoperable and Action Statement 3.9.8.2 was entered. No. 11 RHR pump was started to provide RHR flow.	The apparent cause was mechanical seal failure.	The mechanical seal in No. 12 RHR pump was replaced and surveillance test 4.0.5.P was satisfactorily performed.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Salem-1 272-83001 830104	Modes 4/5	The Control Room operator observed that No. 1B vital bus had tripped. Since it is supplied from the bus, No. 12 residual heat removal (RHR) pump was deenergized; loss of the pump rendered the associated RHR loop inoperable and Action Statement 3.4.1.4A was entered. The operator immediately started No. 11 RHR pump to restore core cooling flow. The second pump remained operable.	Investigation revealed that the bus had tripped due to differential relay protection. No apparent cause for the trip was evident and the bus tested satisfactorily. Power was restored and no further problems were noted. No. 12 RHR pump was declared operable and the action statement was terminated.	None.
Farley-1 348-83009 830307	Mode 6	The A Train RHR system was declared inoperable when the 1A RHR pump was inadvertently secured.	This event was due to a misinterpretation of instructions. The shift supervisor's instructions were to secure RHR letdown and charging so maintenance could be performed on valve HV-142. The instructions were interpreted to mean that RHR letdown and charging should be secured. As a result, the 1A RHR pump was inadvertently secured. Immediately upon discovery of the error, the 1A RHR pump was started and A Train RHR System was declared operable at 0026 on 3/7/83.	The personnel involved were instructed to insure that future communications are clear and concise.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
North Anna-2 339-83031 830408	Mode 5	On 4/8/83 power was lost to the A Residual Heat Removal (RHR) subsystem when the 2H 4160 volt emergency bus was de-energized. This action resulted in leaving only one coolant loop (B RHR subsystem) operable. A single RHR loop provides sufficient heat removal capability in Modes 4 or 5.	This event was initiated when the A and B phase 6 amp secondary fuses for the 2H emergency bus undervoltage test circuit failed. As a result, the undervoltage relays dropped out causing the bus to shed load. Since the H emergency diesel was tagged out, the bus could not be re-energized. The B RHR pump was started.	The fuses replaced and the H emergency bus re-energized
Salem-2 311-83014 830413	Mode 5	On 2 separate occasions, on 4/13 and 4/18, operating loads on the No. 2A 4KV and 460V vital buses were observed to trip. In both cases, due to the de-energization of No. 21 Residual Heat Removal (RHR) pump No. 21 RHR loop was no longer in operation. In each instance, the RHR loop was immediately returned to operation.	Investigation revealed that the problems were evidently due to the Safeguards Equipment Control System.	A contract has been written for further investigation by an experienced consultant. Appropriate corrective action will be taken upon completion of the investigation.
Ginna 244-83017 830501	Mode 5 - The A and B RHR pumps were running (B pump started at 2109 hours) and taking suction from the Refueling Water	The RWST level had decreased to 20% level which required by procedure to stop one RHR pump. The A RHR pump was stopped and flow dropped to zero. Control Room operator noticed MOV-704B (B RHR pump suction valve) closed. The A RHR pump was restarted and	On 4/27/83, MCC D was out of service to inspect MCC D circuit breaker on Bus 16 using M-37.1. The motor control center's breaker was held between 0700 and 0957 but the control power fuses were still in place on MCC D breakers. During this time	None.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Ginna (continued)	Storage Tank (RWST) for filling the Reactor Refueling Cavity in preparation for refueling operations.	flow reestablished and the B RHR pump stopped. Thus for a period of less than two hours while filling the reactor cavity the B RHR pump was run with its suction valve closed. The auxiliary operator checked B RHR pump and found it warm but no seal leakage. The pump was tested for flow and vibration with conditions found normal.	an attempt was made to stroke MOV-704B per steps 6.18.2.4 and 6.18.3.4 of PT-2.3 by Tests and Results personnel. PT-2.3 was an on-going procedure that was started 4/13/83. Because the power was off MCC D and the control power fuses to its breakers still in place, when the attempt was made to stroke MOV-704B to see if temporary power had been supplied to this breaker, the valve status lights did not change. Therefore, no entry was made in the official log or in PT-2.3.	
Salem-2 311-83025 83-524	Mode 5	No. 21 Residual Heat Removal (RHR) pump and No. 21 Fuel Handling Building exhaust fan were observed to trip. Deenergization of No. 21 RHR pump resulted in no RHR loop being in operation and Action Statement 3.4.1.4B was entered. The pump was immediately restarted and flow restored. No reduction in Reactor Coolant System Boron concentration occurred with the RHR loop inoperable.	Initial results of detailed investigation of a previous similar problem revealed the problems were due to a floating logic line and internal circuitry noise in the Safeguards Equipment Control (SEC) system.	A testing design change was issued to modify the SEC circuitry.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Salem-2 311-83031 830623	Mode 5	During routine shutdown operation, the Control Room operator observed two different instances in which a spurious Safeguards Equipment Control (SEC) System actuation caused various loads on the No. 2A vital bus to be de-energized. In the second case, the bus infeed breaker opened with no automatic transfer, rendering the bus inoperable. In both instances, due to the loss of the operating Residual Heat Removal (RHR) pump, flow in the operating RHR loop was lost.	The spurious SEC actions are apparently related to internal circuitry noise; further investigation of the problem is underway. RHR flow and power to the vital bus was restored as appropriate and the action statements were terminated.	Appropriate corrective action will be taken upon completion of the investigation.
Beaver Valley-1 334-83020 830629	Mode 6	While performing a design change, a wire on the terminal block for emergency bus supply breaker 1D10 was lifted prematurely prior to establishing an electrical clearance. This caused a phase unbalance in the overcurrent circuitry which tripped the breaker, de-energizing the 1DF bus (T.S 3.8.2.2) and the running RHR pump (T.S. 3.9.8.1). The diesel restored power to the bus and the pump was started 92 seconds later.	A breakdown in communications between shifts resulted in construction personnel being unaware of equipment status.	Construction procedures have been modified to require copies of all clearances and/or area work permits at the work location. Additionally, Construction personnel received retraining concerning clearance procedures.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Farley-2 364-33042 830928	Mode 6	The 2B RHR pump tripped while the B RHR loop was in service and the A RHR loop was secured.	This event was caused by a crack in the lower bearing oil fill drain drain and sight glass pipe. The crack initiated in the third pipe thread and progressed into the eighth pipe thread thereby allowing oil in the lower bearing to drain leading to bearing failure. Preliminary investigations into the pipe failure have revealed that the pipe must be manually rotated 180° for draining and filling the lower bearing with oil. Forces that created an excessive moment about the pipe threads may have been applied to the pipe when performing this activity, thus initiating a crack in the threads.	New design for the bearing oil fill, drain and sight glass pipe is being pursued to alleviate the need for turning of the pipe when draining and filling with oil thereby eliminating the potential of similar failures occurring.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Salem-1 272-84013 840602	Mode 6	Power was interrupted between the 500KV yard and the 13KV bus, resulting in a loss of onsite power to the Unit 1 and Unit 2 KV group and vital busses. Unit 1 was in a refueling outage at the time with the reactor defueled and Unit 2 was in cold shutdown. Unit 2 emergency diesel started and loaded in the blackout mode; Unit 1 emergency diesels and 1B vital bus were cleared and tagged for maintenance. Unit 2 RHR pumps were removed from service by the SEC sequencer, resulting in a loss of residual heat removal flow. Power was restored to all group busses within thirty seconds. Control of vital bus loads was regained and RHR was immediately restored. Unit 2 vital busses were then transferred to station power and the diesels were secured.	The event was the result of a nuclear control operator opening the wrong 500KV circuit switchgear. This was due to not fully understanding the switchgear controls that were available to him and not reading the label on the console control prior to its operation. This event was aggravated by relaying the order to Unit 2 Control Room via the Unit 1 Control Room NCO.	The individual involved was counseled and reprimanded for his actions associated with the event. Two newsletter items discussed the incident and causes due to the loss of RHR.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Zion-2 304-86005-1 860117	Mode 5	The Unit 2 reserve feed breaker 2432 (suppling power from the system auxiliary transformer to service bus 243) tripped while an electrician was repairing the "closed" (red) light socket on the main control board. Loss of power to service bus 243 resulted in a loss of power to Engineered Safety Feature Bus 248 and thus Residual Heat Removal (RHR) 2B pump, which is powered off of Bus 248, tripped. All equipment affected by this loss of power functioned properly. Specifically, diesel generator 2A autostarted and carried all loads associated with Engineered Safety Feature bus 248. The operator started RHR pump 2A to maintain reactor coolant system temperature.	The reserve feed breaker tripped because the electrician accidently shorted out the trip coil. The operator allowed the electrician to finish repairing the light socket while the diesel generator carried the ESF bus 248 loads.	To prevent this problem from recurring, training for all operating and electrical maintenance personnel will be implemented so that such maintenance activities will not be allowed to close breakers.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Crystal River-3 302-86003 860202	Mode 5	The Reactor Coolant system was vented to the Reactor Building atmosphere and drained below the level of the reactor coolant pumps. At 2148 hours, decay heat pump tripped due to a motor overload caused by a pump shaft failure. Start up of the redundant pump was delayed because an isolation valve on the suction side of the pump could not be opened from the Control Room. The valve was manually opened and system operation was restored at 2212 hours. On 2/12/86, the B train of the Decay Heat Removal System was being refilled and movement of the pump and piping was noticed. Examination of pipe restraints in the system revealed that several pipe hangers were loose or damaged. All damaged equipment has been repaired. Both decay heat pumps have been rebuilt.	No clear root cause.	Decay Heat Removal System Operating Procedures have been revised to address minimum required reactor coolant level and provide fill and vent instructions. New breaker and torque switch settings have been established for the isolation valve. Preventative maintenance procedures will require periodic lubrication of the valve drive shaft.
Surry-1 280-86017 860524	Mode 6	On 5/24/86, Unit 1 was at refueling shutdown with Reactor cavity flooded and forced circulation in service; Unit 2 was at 100% power. Due to maintenance and design change work in progress on Unit 1, numerous	None.	None.

TABLE A-6: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: LOSS OF FLOW DUE TO LOSS OF THE RUNNING RHRS PUMP

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Surry-1 (continued)		electrical busses were cross tied. Among these were 1h and 1J 4160V emergency busses and vital busses 1-II and 1-IV. #1 emergency diesel generator was out of service. At approximately 1520 hours, reserve station service feeder breaker 15Da opened. This resulted in an undervoltage transient sensed at 1J emergency bus. #3 emergency diesel generator autostarted and assumed load. By design, the 1J stub bus breaker opened during the transient which resulted in the loss of the operating 1B residual heat removal and 1B component cooling pumps. The stub bus breaker was reset and the components were returned to service. Numerous spurious trip signals, alarms and A HI Consequence Limiting Safeguards signal were generated during the transient.		

TABLE A-7: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: INTENTIONAL LOSS OR DEGRADATION OF RHRS FOR PLANNED MAINTENANCE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Turkey Point-3 250-85034 851023	Mode 5	At 0915 on 10/23/85, the 3A Residual Heat Removal (RHR) pump was declared out of service (OOS) when it did not meet the seal leakoff acceptance criteria during an operability test. At this time, the B emergency diesel generator (EDG) was OOS for maintenance. This placed the unit in a condition where upon loss of off-site power, no RHR loop would be available for core cooling for approximately 18 hours. Plant management decided since the 3A RHR pump could still operate and pump water to leave it lined up to the RHR system until the B EDG was returned to service. This would allow for core cooling in the event that off-site power was lost. TS 3.4.1.E requires two coolant loops be operable and one coolant loop in operation whenever the Reactor Coolant System (RCS) temperature is less than 350°F. The 3A RHR pump being OOS exceeded the requirements of this TS. During this event, Unit 3 was in cold shutdown with the 3B RHR pump providing core cooling. The A EDG was operable and the 3A RHR pump was lined up	The cause of the event was the failure of the 3A RHR pump mechanical seal.	None.

TABLE A-7: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: INTENTIONAL LOSS OR DEGRADATION OF RHRS FOR PLANNED MAINTENANCE

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Turkey Point-3 (continued)		to the RHR system to allow for core cooling in the event of a loss of off-site power until the B EDG was placed back in service. No heat up of the Reactor Coolant System was observed while the B EDG was OOS.		

TABLE A-8: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: INABILITY TO ESTABLISH RHRS FLOW - DUE TO INABILITY TO OPEN RHRS SUCTION VALVES

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Robinson-2 261-82009 820715 & 820727	Mode 6 - Plant Heatup from a refueling outage in progress.	On both occasions, motor operated valve, RHR-759A, a residual heat removal exchanger discharge valve, failed to open.	The cause of failure was improper setting of the motor operator torque switch with insufficient lubrication of the valve stem and packing as a contributing factor.	The valve stem and packing were lubricated, the torque switch was set at the proper value. Maintenance instructions, which include torque settings, are being developed for each safety-related motor operated valve.
San Onofre-2 361-83038 830426	Mode 4	Preparations in progress for Mode 3 entry, Shutdown Cooling System (SDCS) heat exchanger isolation valves 2HV8150, 2HV8152 and 2HV8153 could not be remotely operated from the Control Room upon initiation of shutdown cooling to avoid personnel radiation exposure from local operation.	The inability of the valves to remotely open was attributed to incorrect open sequence torque and limit switch settings. The incorrect settings caused the motor on the valves to stop before the valves had come off their seats.	The limit and open sequence torque switch settings were adjusted and the valves successfully stroke tested from the Control Room on 4/26/83.

TABLE A-8: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: INABILITY TO ESTABLISH RHRS FLOW - DUE TO INABILITY TO OPEN RHRS SUCTION VALVES

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Ginna 244-84002 840303	Mode 4	While cooling down the Reactor Cooling System (RCS) to cold shutdown condition for the annual refueling and maintenance outage periodic test PT-2.4.1, cold/refueling motor operated valve surveillance (RHR system - 700 valves) was in progress. MOV-700 (RCS loop A Residual Heat Removal suction stop valve) failed to stroke to the open position when actuated from the Control Room.	Following manual unseating of the valve, the valve was retested and stroking times were verified acceptable (timed twice, full cycle).	None.
Ginna 244-84005 840514	Mode 4	On 5/14/84, while cooling down the Reactor Coolant System (RCS) to the cold shutdown conditon for sludge lancing and crevice cleaning, MOV-700 (RCS Loop A Residual Heat Removal Suction Valve) failed to stroke to the open position when actuated from the Control Room. Following manual unseating of the valve, maintenance personnel performed an inspection of the valve exterior. This inspection revealed that the packing gland flange had shifted out of the vertical position to a point where the flange was in contact with the valve stem. This could have cause a mechanical binding in the stem and torque-out of the valve operator. The valve	Unknown.	None.

TABLE A-8: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: INABILITY TO ESTABLISH RHRS FLOW - DUE TO INABILITY TO OPEN RHRS SUCTION VALVES

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Ginna (continued)		was then stroked manually to verify no mechanical binding. The valve was then stroked twice electrically. The valve functioned satisfactorily with proper motor current readings and acceptable opening and closing times indicating no mechanical binding. A visual inspection of the valve stem and stem threads verified adequate cleanliness and lubrication. Torque switch settings were verified within the manufacturers design settings. On 5/22/84 when the RCS was heating up to hot shutdown, the valve was again stroked to verify proper operation. Again, the valve functioned properly with proper motor current readings and acceptable opening and closing times. Operation of this valve will continue to be monitored during the next cooldown of the RCS.		
Oconee-3 287-85003 851015	Mode 4	An unsucessful attempt to open an electric motor operated (EMO) valve (3LP-2) was made from the Unit 3 Control Room. Unit 3 was in hot shutdown after coming off-line for maintenance. The valve is	The cause of the incident was the torque switch settings on the valve. Rotork Nuclear Actuator settings were not set high enough to operate the valve under system	The immediate corrective action was to open the valve from the valve actuator contactors at the Motor Control Center, bypassing the valve actuators torque switch limit control.

TABLE A-8: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: INABILITY TO ESTABLISH RHRS FLOW - DUE TO INABILITY TO OPEN RHRS SUCTION VALVES

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Oconee-3 (continued)		required to open in order to indicate the decay heat removal cooling mode.	pressure. The EMO valve torque switch settings were not specified in the Design Modification package used to replace the valve actuator with a new Rotork Nuclear Actuator.	

TABLE A-9: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: RCS VOID FORMATION DURING RHRS OPERATIONS

[NO EVENTS]

TABLE A-10: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: MISCELLANEOUS LOSS OF RHRS EVENTS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
San Onofre-2 361-82002 820314	Mode 6	Shutdown cooling was lost due to nitrogen intrusion as a result of backflushing a filter in the purification system. Shutdown cooling flow was lost for 90 minutes. Public safety was not endangered because no irradiated fuel was in the core.	A system malfunction or operator error allowed pressurized nitrogen to enter the shutdown cooling pump suction line.	The procedure for backflushing this filter will be revised to require isolation of the Purification System during flushings when shutdown cooling is in service.
Maine Yankee 309-82032 820929	Mode 6	A small amount of Xe-133 activity was discovered in the secondary component cooling system during weekly surveillance sampling. The previous weekly sample showed no activity. Further investigation indicated that the contamination probably came from the Reactor Coolant System via a transient leak in the E-3B RHR heat exchanger associated with the thermal transient which occurs when RHR is placed in operation. The activity level was well below the detectability threshold of the system monitor. There was no effect on the ability of the E-3B RHR heat exchanger to perform its intended safety function. The SCC system is closed and normally provides no direct	Only gaseous activity was detected in the SCC system. None of the other reactor coolant activity constituents were evident by Gamma spectroscopic analysis, indicating that any leak path that may exist across the E-3B RHR heat exchanger is so minute that it only passes gaseous activity. Additional sampling while the 3-3B heat exchanger has been operating in refueling shutdown cooling mode has revealed no further evidence of a leak.	The procedure for surveillance sampling of SCC and PCC shall be revised to require a sample within 24 hours of placing the heat exchangers within the RHR Mode.

TABLE A-10: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: MISCELLANEOUS LOSS OF RHRS EVENTS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Maine Yankee (continued)		release path. The primary component cooled E-3A RHR heat exchanger was not affected. Continued sampling of SCC while on RHR during refueling shows no further evidence of leakage.		
Arkansas Nuc One-2 368-83003 830109	Mode 5	An alarm was received on the Service Water (SW) monitor (WRITS-1453) for the shutdown cooling (SDC) heat exchanger (2E-35A) which indicated the possibility of a tube leak. Radiochemistry sampling verified the tube leak. 2E-35A was secured and the redundant heat exchanger (2E-35B) was placed in service. Since this leak from the SDC system to the SW system was a degradation of a system designed to contain radioactive mater. A previous occurrence regarding SDC tube leaks was reported in LER-79-086. It should be noted that this heat exchanger tube bundle had been replaced during the last Unit 2 refueling outage.	Testing and inspections revealed tube leakage and tube-to-tube sheet weld leakage. The exact cause of degradation could not be determined.	Corrective action was to plug a total of 18 tubes. 2E-35A was tested and no leak indications were found.
North Anna-1 338-83009 830218	Mode 5	On 2/18/83, indications of cavitation were observed on B Residual Heat Removal (RHR) pump and later on A RHR pump. The B pump was started and	The cause of the incident is not known.	Subsequent operation after the event has been without incident. With both RHR pumps secured, the containment operator vented each

TABLE A-10: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: MISCELLANEOUS LOSS OF RHRS EVENTS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
North Anna-1 (continued)		returned to service in approximately 5 minutes. An RHR pump operability was subsequently verified.		pump. However, no air was observed. The B RHR pump was restarted, vented (no air observed) and restored to service. The A pump was subsequently restored to service.
McGuire-2 370-83002 830307	Mode 6	While moving a temporary in-core detector, the rope used to hold the detector cable fell into the reactor vessel and was drawn into C Hot Leg. Residual Heat Removal (RHR) Pump 2A was secured from service for 3 hours (with Pump 2B also secured) to allow rope retrieval efforts.	This incident is a result of personnel error due to loose material being allowed in vicinity of the open vessel. Fuel loading was suspended and no decrease in Boron concentration was made with the pumps secured. Following unsuccessful retrieval efforts, pump 2A was restarted and fuel loading completed. The rope was found wrapped around RHR pump impeller HUB and removed on 3/15/83.	Personnel will be counseled.
Indian Point-3 286-83002 830512	Mode 5	A small leak was identified on the RHR miniflow at the weld joint between valve 1870 and Line 337.	The leak was isolated.	The section of pipe between valve 1870 and A downstream reducer was replaced on May 17, 1983.

TABLE A-10: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: MISCELLANEOUS LOSS OF RHRS EVENTS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Santa Anna-2 339-83042 830522	Mode 4	On 5/22/83, RCS unidentified leakage exceeded the limits specified in T.S. 4.6.2 (< 1 gpm). The source of the leak was identified and isolated within 30 minutes. The leak was promptly isolated and the unit placed in Mode 5 within 9 hours.	The excessive leakage was a result of a shaft sleeve gasket failure on the A Residual Heat Removal (RHR) pump. The gasket was ripped and broken apart. No cause for the gasket failure could be determined.	The leak was stopped by securing and isolating the A RHR pump. Unit 2 was placed in Mode 5, the mechanical seal and sleeve gasket replaced and the pump restored to service.
Rancho Seco-1 312-83023 830526	Mode 6	The A RHR pump failed to start on demand. The breaker did not indicate protection lock-outs so the breaker was racked out, then racked back in.	The breaker was inspected and function tested for problems. None were found so this will be considered a one-time event.	None.
Byron-1 454-85070-1 850724	Mode 1	On 7/24/85, at approximately 2230 hours during the performance of the ASME quarterly surveillance test for the B train Residual Heat Removal (BP)(RH) pump (1RH01PB) vibration readings for the pumps upper motor bearing exceeded the acceptance criteria limits. The applicable Tech. Spec. action requirement was to repair the pump within 72 hours or be in hot standby in 6 hours and hot shutdown in the following 6 hours. Attempts were initiated within the initial 72 hour period to	The principle cause of the failure was motor vibration inducing excessive forces on the motor runner due to the cantilever effect of the motor modification M6-1-85-0556.	To minimize the cantilever action of the pump/motor assembly, has been initiated and approval for installation was granted on 2/3/86.

TABLE A-10: ACTUAL LOSSES OR DEGRADATIONS OF OPERATING RESIDUAL HEAT REMOVAL SYSTEMS

EVENT CATEGORY: MISCELLANEOUS LOSS OF RHRS EVENTS

PLANT LER/DATE	INITIAL PLANT CONDITIONS	EVENT DESCRIPTION	REPORTED CAUSE	CORRECTIVE ACTION
Byron-1 (continued)		restore the RH pump to service. When it became apparent that the pump would not be restored, the Station opted to achieve hot standby by conducting a start up test that required a plant trip from the existing power level. The Reactor Coolant System (RCS) was maintained at 360°F ti expedite the return to power until the duration of repair mandated entry into hot shutdown (RCS temperature less than or equal to 350°F).		

APPENDIX B

THERMAL HYDRAULIC ANALYSIS OF SELECTED SCENARIOS

PLG-0595

APPENDIX B

THERMAL-HYDRAULIC ANALYSES OF POSTULATED LOSS OF DECAY HEAT REMOVAL EVENTS DURING SHUTDOWN

by
David R. Buttemer

Prepared for
PUBLIC SERVICE OF NEW HAMPSHIRE
New Hampshire Yankee Division
Seabrook, New Hampshire
December 1987

Pickard, Lowe and Garrick, Inc.
Engineers • Applied Scientists • Management Consultants
Newport Beach, CA Washington, DC

CONTENTS

LIST OF TABLES AND FIGURES

Tables

Figures

APPENDIX B

THERMAL-HYDRAULIC ANALYSES OF POSTULATED LOSS OF DECAY HEAT REMOVAL EVENTS DURING SHUTDOWN

This appendix evaluates the plant thermal-hydraulic response to several postulated loss of decay heat removal scenarios during shutdown. In each case analyzed, it is assumed that the plant had been previously operating continuously at full power for 18 months. The time after shutdown when decay heat removal is lost is treated as a parameter, ranging from 1 day to 1 week.

Appendix B.1 evaluates loss of decay heat removal events when the reactor vessel is vented and remains at atmospheric pressure. Two initial water level cases are analyzed: (1) water level initially at the center line of the hot leg piping (which could occur during steam generator repair) and (2) water level initially at the vessel flange. Initial water temperature is [illegible] to be 140 F. The steam generators are dry. Solid heat capacities of the core, reactor internals, and portions of the vessel and piping are included. The degree of heat transfer between the heated water inside the core barrel and the cooler water in the lower plenum and downcomer regions is treated parametrically. Water pressure is taken to be 14.7 psia. The length of time to heat up the water to boiling and the length of time to boil off the water to the top of the core are evaluated. An additional analysis is made to evaluate the increase in fuel rod temperature as core uncovery progresses; this analysis includes fuel rod heat capacity and steam cooling effects.

Appendix B.2 considers the case in which the reactor coolant system is not vented, the steam generators are dry, the vessel is filled with water, and RHR cooling is lost. The loss of vessel water inventory through the RHR relief valves, the increase in RCS pressure, and the effect of automatic RHR isolation on high pressure are determined.

The case in Appendix B.3 is similar to the case analyzed in Appendix B.2 except that water is initially in the secondary side of some steam generators. The corresponding time delay afforded by steam generator inventory boiloff is evaluated.

Appendix B.4 evaluates the vessel-venting ability when decay heat removal is lost. Different combinations of possible vent paths are evaluated to determine whether the equilibrium vessel back pressure is sufficiently low to allow gravity feeding of the borated RWST water into the reactor vessel.

The results from the various analyses are shown in the following figures:

- Figure B-1 shows the time to core uncovery when the vessel is at atmospheric pressure and the initial water level is at the hot leg center line.

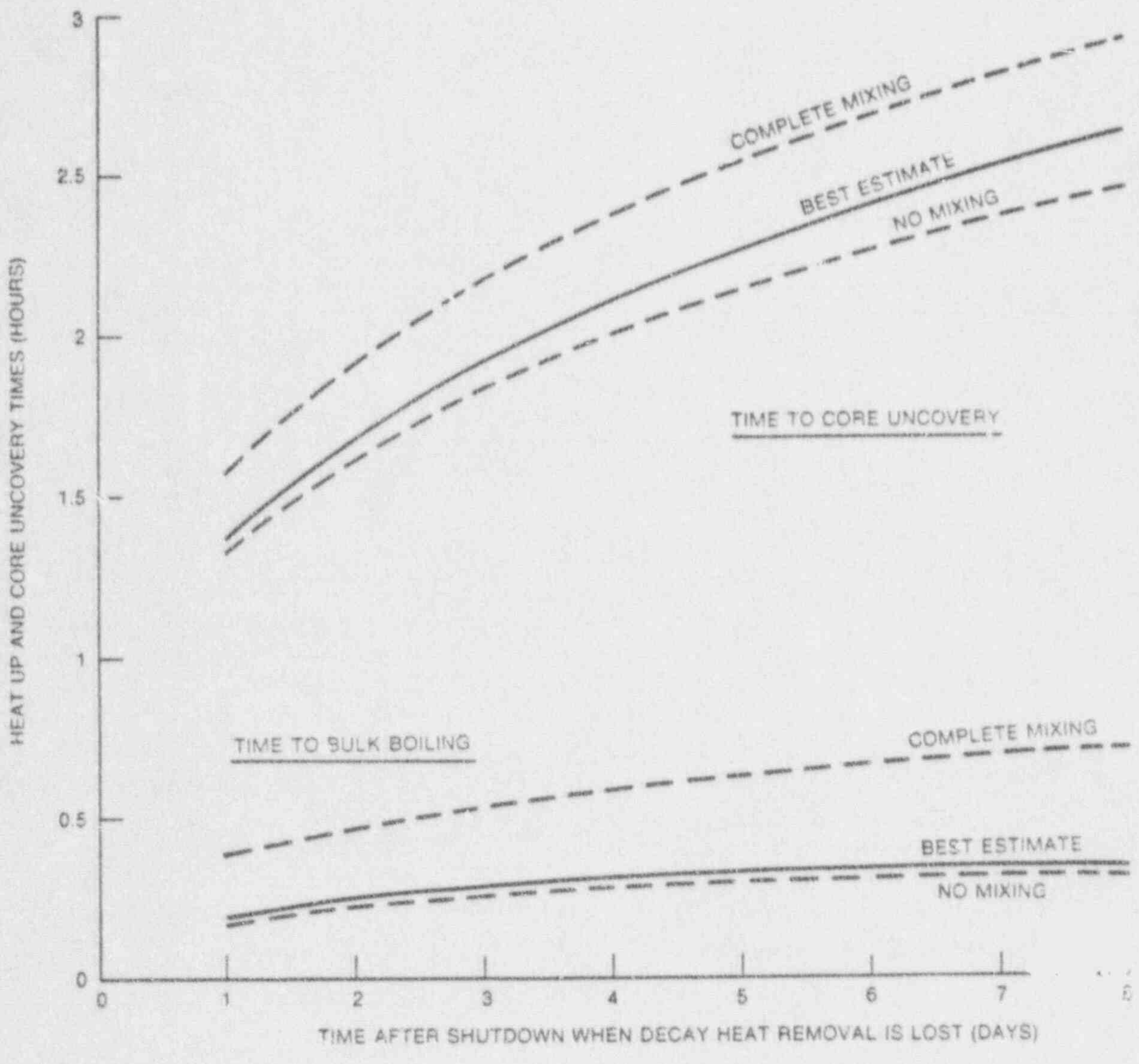


FIGURE B-1. TIME TO BULK BOILING AND CORE UNCOVERY - WATER LEVEL INITIALLY AT HOT LEG CENTER LINE

- Figure B-2 shows the length of time to core uncovery when the vessel is at atmospheric pressure and the initial water level is at the vessel flange.

- Figure B-3 shows the fuel rod heatup transient during core uncovery.

- Figures B-4 and B-5 show the water level and vessel pressure response when the vessel is full and when it is closed, with dry steam generators, for 1 and 3-day shutdown times, respectively. Results are presented both with and without RHR isolation.

- Figure B-6 shows the time it takes to boil off the secondary-side inventory from two steam generators.

B.1 LOSS OF DECAY HEAT REMOVAL EVENTS WITH THE REACTOR VESSEL HEAD REMOVED

B.1.1 EVENT SCENARIOS AND ANALYSIS ASSUMPTIONS

These classes of events consider the plant in mode 5, the reactor coolant system open or vented, and the vessel filled either to the top of the vessel flange (presumably in preparation of refueling operations) or to the midplane of the hot leg (presumably in preparation of steam generator repair work). The residual heat removal system is assumed to be operable and to maintain the average RCS water temperature at 140°F prior to the loss of decay heat removal event. Solid heat capacities of the core and those portions of the reactor internals, reactor vessel, and piping that are in direct contact with the water are included in the heatup and boiloff calculations. Any condensation and condensate drainback from cool structures located above the water level is neglected. All core and reactor internal heat capacities are included because of their large heat transfer surface area-to-volume ratios. However, because of the thick reactor vessel metal sections that are cooled on only one surface, only 75% of the cylindrical wall and 90% of the lower head heat capacities are included in the analyses. Analyses to substantiate these fractions are provided later.

When decay heat removal is lost, the water in and above the core will begins to heat up because of strong convection currents, heating the water in the hot legs. The water below the core, in the downcomer region and in the cold legs heats up more slowly because of conduction and convection heat transfer mechanisms, which, as discussed later, take several hours to be effective. Two extreme cases are analyzed: the first assumes no heat transfer between the hot and cold regions (resulting in the fastest heatup rate), and the second assumes instantaneous and complete thermal mixing between the two regions (resulting in the slowest heatup rate).

B.1.2 BASIC INPUT DATA

This section develops Seabrook Station-specific data for use in subsequent analyses. These data include decay heat rates for various operating periods as a function of time after shutdown, material property data for evaluating solid heat capacities, and system liquid and solid volumes.

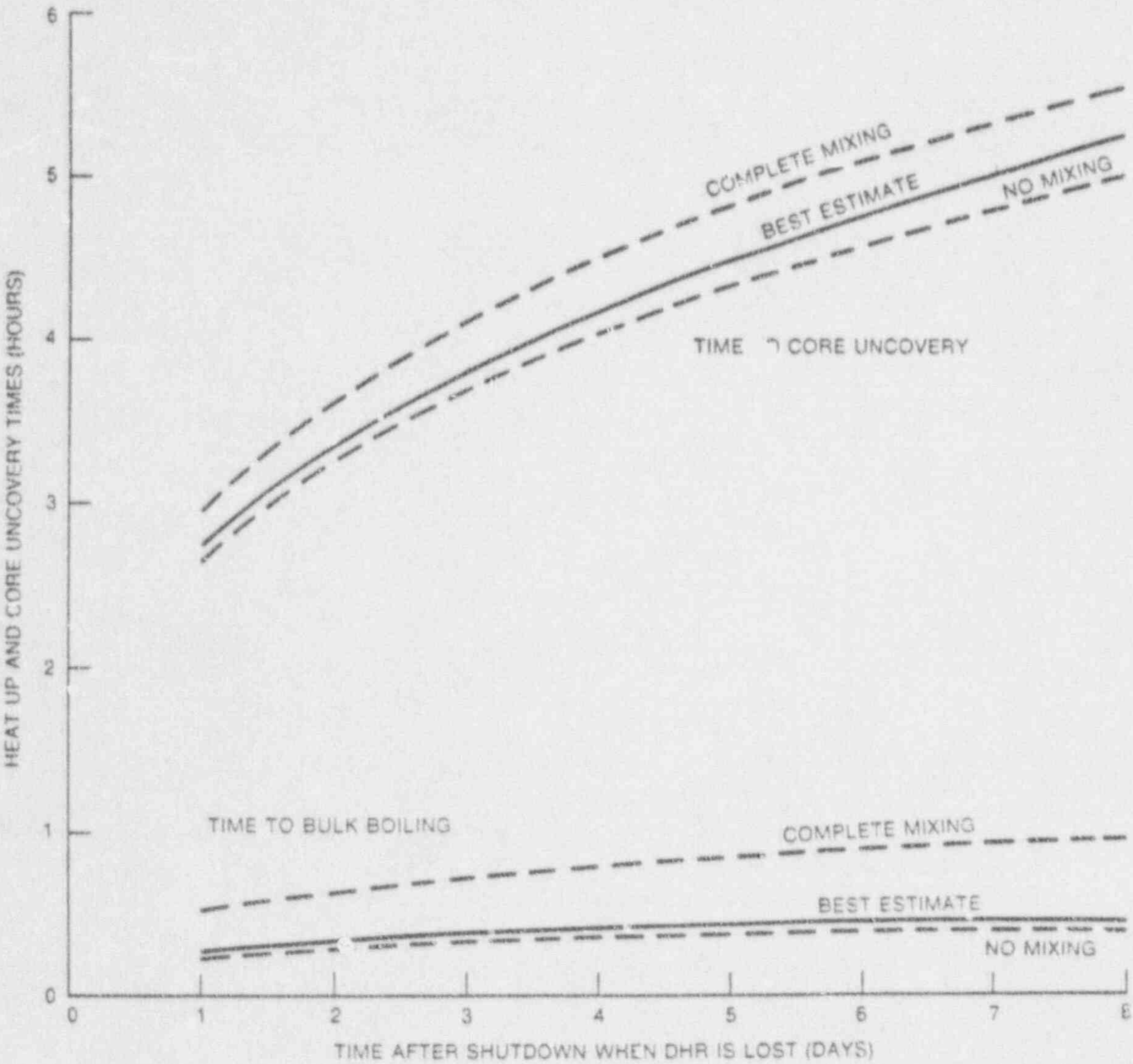


FIGURE B-2. TIME TO BULK BOILING AND CORE UNCOVERY - WATER LEVEL INITIALLY AT VESSEL FLANGE

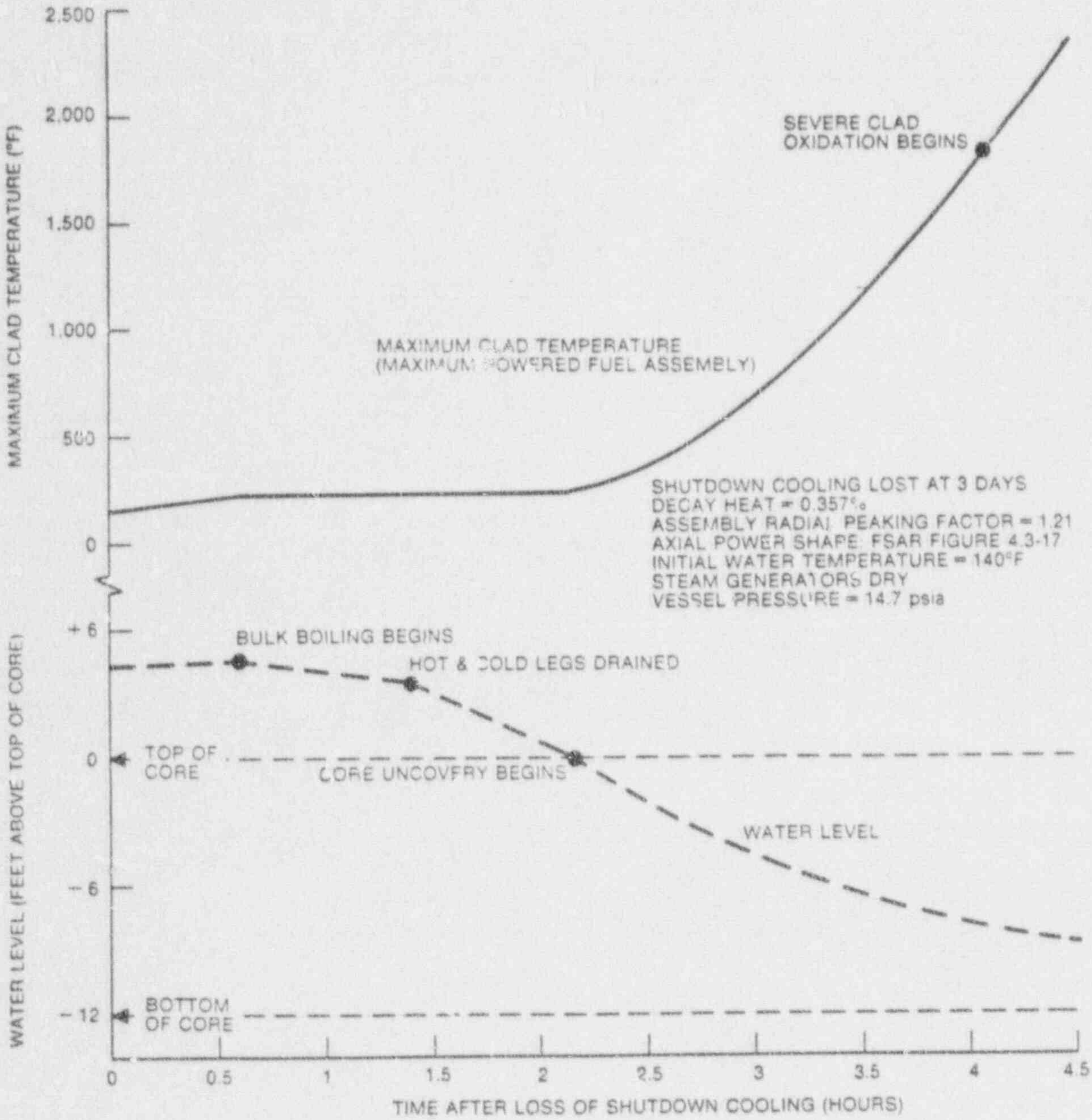


FIGURE B-3. FUEL ROD HEATUP TRANSIENT DURING CORE UNCOVERY

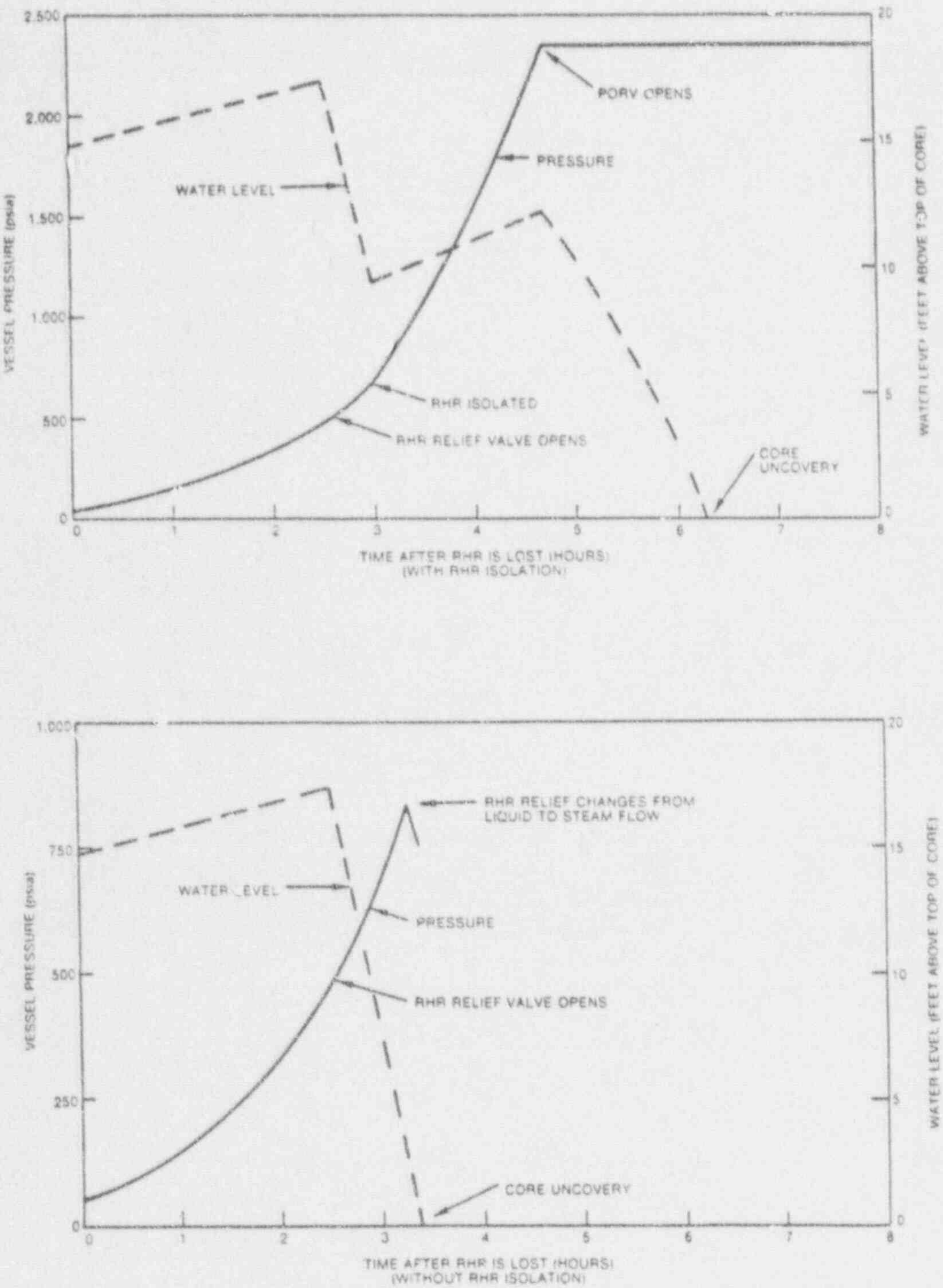


FIGURE B-4. LOSS OF RHR WHEN VESSEL IS FULL AND CLOSED WITH STEAM GENERATOR SECONDARY SIDES DRY - 1 DAY AFTER SHUTDOWN

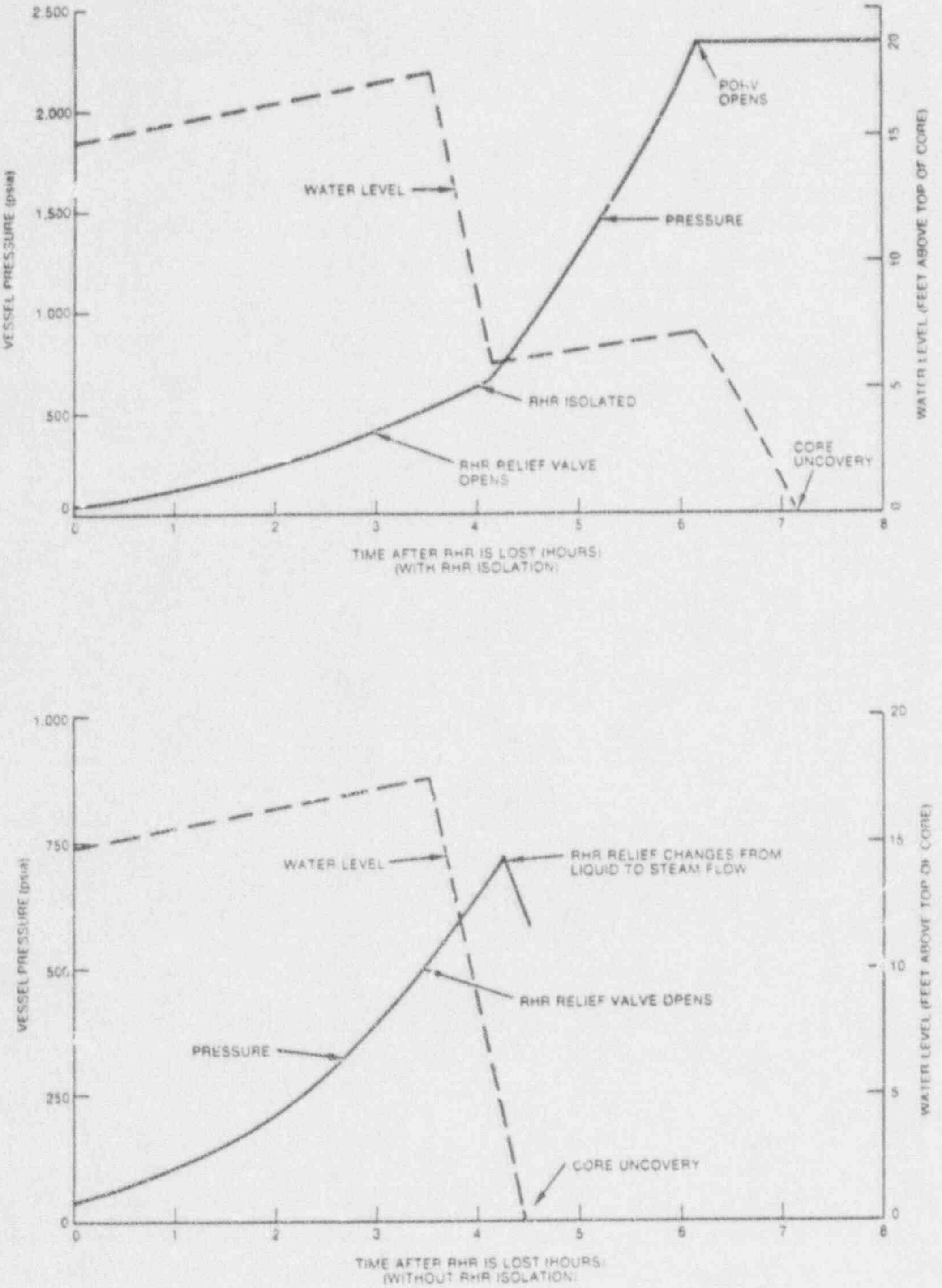


FIGURE B.5. LOSS OF RHR WHEN VESSEL IS FULL AND CLOSED WITH STEAM GENERATOR SECONDARY SIDES DRY - 3 DAYS AFTER SHUTDOWN

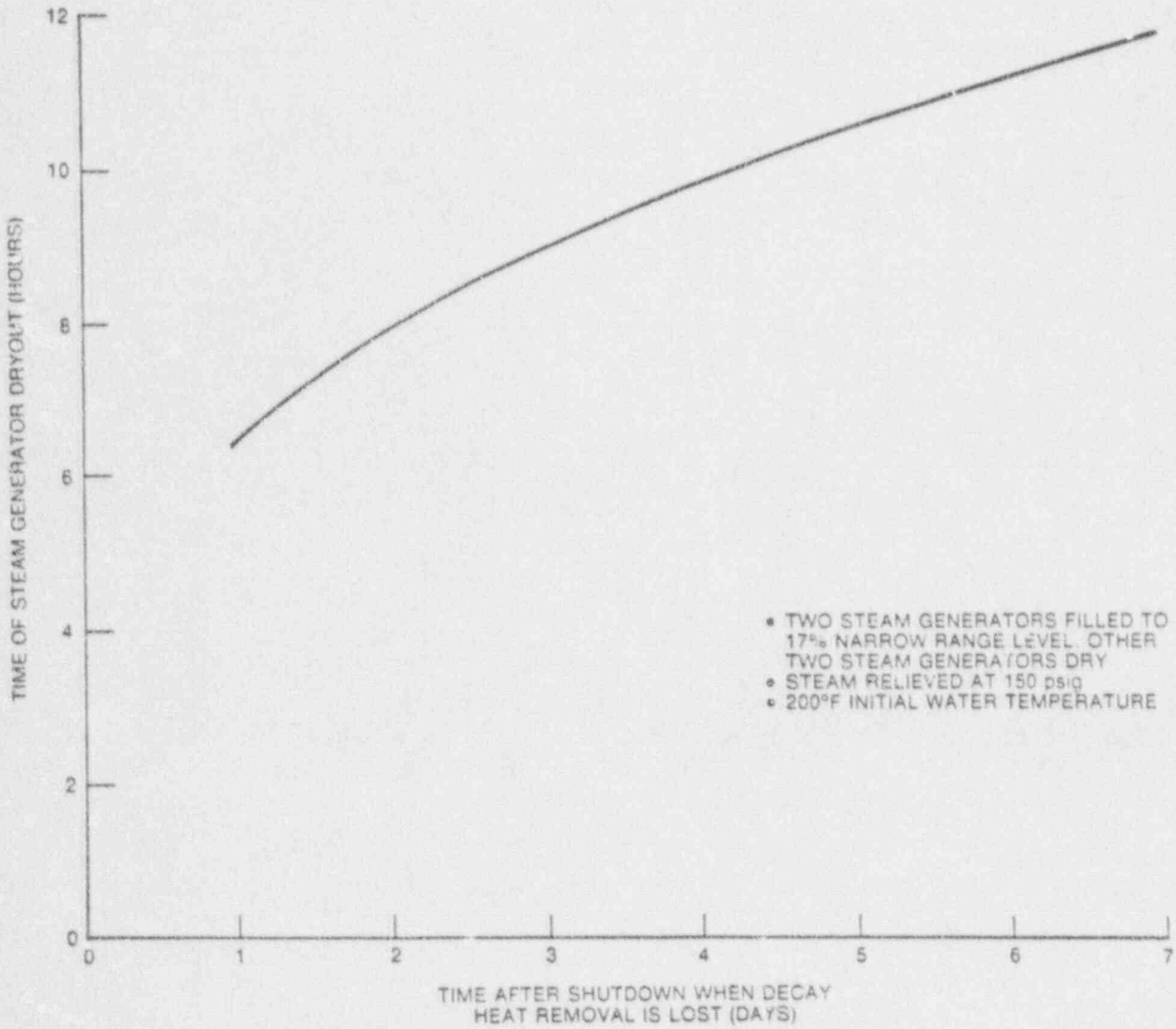


FIGURE B-6. TIME OF STEAM GENERATOR DRYOUT

Figure B-7 provides decay heat and integral decay heat information for 1 and 18 months of continuous operation using procedures described in Reference B-1. Integral decay heat is expressed in initial power seconds (IPS). Full power at Seabrook Station is 3,411 MWt, so

$$1 \text{ IPS} = 3.23 \times 10^6 \text{ Btu of thermal energy}$$

Specific heat and density data used to evaluate the heat capacities of various solid materials are shown in Table B-1. Water and steam thermodynamic properties are evaluated from Reference B-4.

From Table 4.1-1 of the FSAR, the total weights of UO_2 and clad (Zircalloy-4) are 222,700 lbm and 45,200 lbm, respectively. There are 50,952 fuel rods in the core, each having an outside diameter and length of 0.374 inch and 151 inches, respectively. The total fuel rod volume is calculated to be 489 cubic feet.

Since different initial water volumes (i.e., at hot leg midheight and at vessel flange) and different thermal-mixing models are used in the analyses, the volumes within the reactor vessel and their associated solid heat capacities are based on the regional subdivisions shown in Figure B-8. Region 1 includes the core and the volume directly above the core. Region 2 includes the four hot legs. Region 3 includes the inlet plenum below the core, the downcomer volume between the core barrel and reactor vessel, and the volume above the grid plate of the upper internals. Region 4 includes the four cold legs. The fluid volumes and solid heat capacities for each subregion are evaluated below.

- Region 1a - Core Barrel, Core, and Contained Water - Active Core Height. This region quickly heats up following loss of decay heat removal because of core decay heat. From Westinghouse Drawing 1455E24, Revision 1, the total assembly weight of the lower internals is 280,000 lbm, the center of gravity is slightly below the core midplane, the core barrel outside diameter is 152.5 inches, and the material is austenitic stainless steel. The assembly weight (and volume) is subdivided into the various regions (as noted in Figure B-8) as follows: 30% in 1a, 15% in 1b, 10% in 1c, 10% in 3d, and 35% in 3a. The total volume of lower internals metal (stainless steel) is 568 cubic feet. The core length is taken to be 151 inches. The total volume of region 1a is

  $$\pi/4 \times 152.5^2 \times 151/1,728 = 1,596 \text{ ft}^3$$

  The volume of lower internals is

  $$0.3 \times 568 = 170 \text{ ft}^3$$

  with a solid heat capacity of

  $$170 \times 493 \times 0.12 = 1.01 \times 10^4 \text{ Btu/°F}$$

  The volume of fuel rods is 489 cubic feet, and the combined clad and fuel pellet solid heat capacity is

  $$222,700 \times .059 + 45,200 \times .081 = 1.68 \times 10^4 \text{ Btu/°F}$$

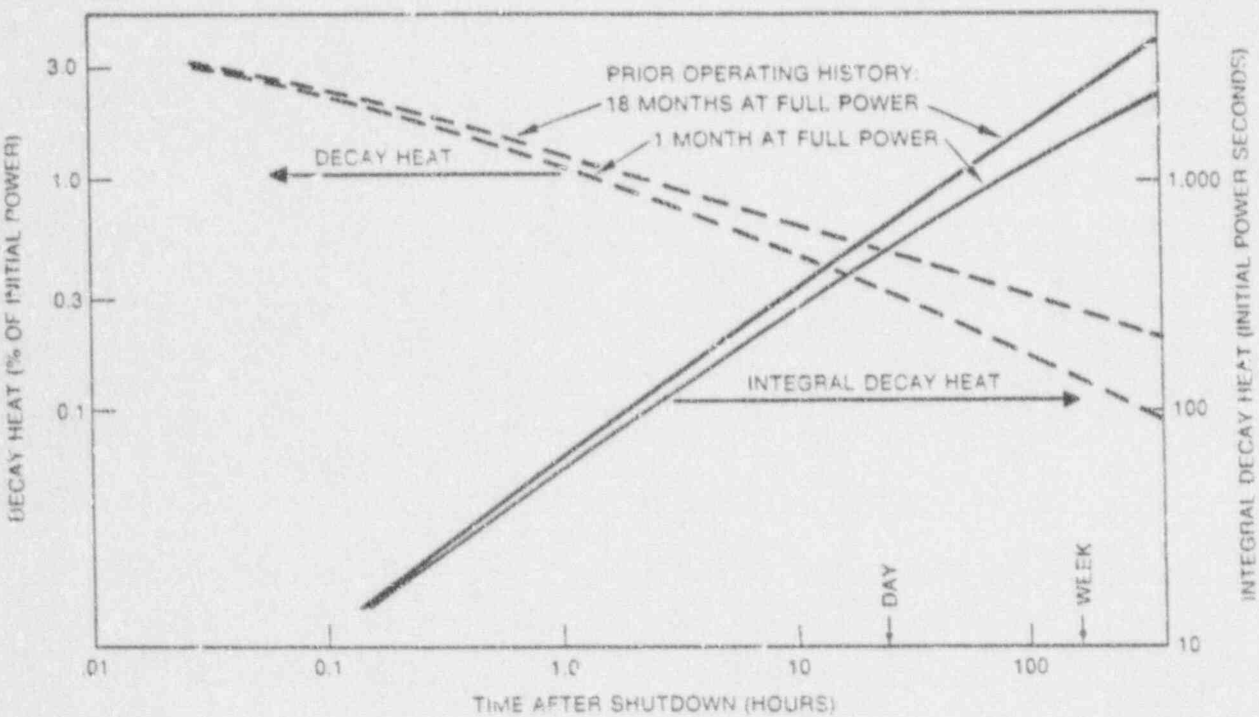


FIGURE B-7. DECAY HEAT AND INTEGRAL DECAY HEAT

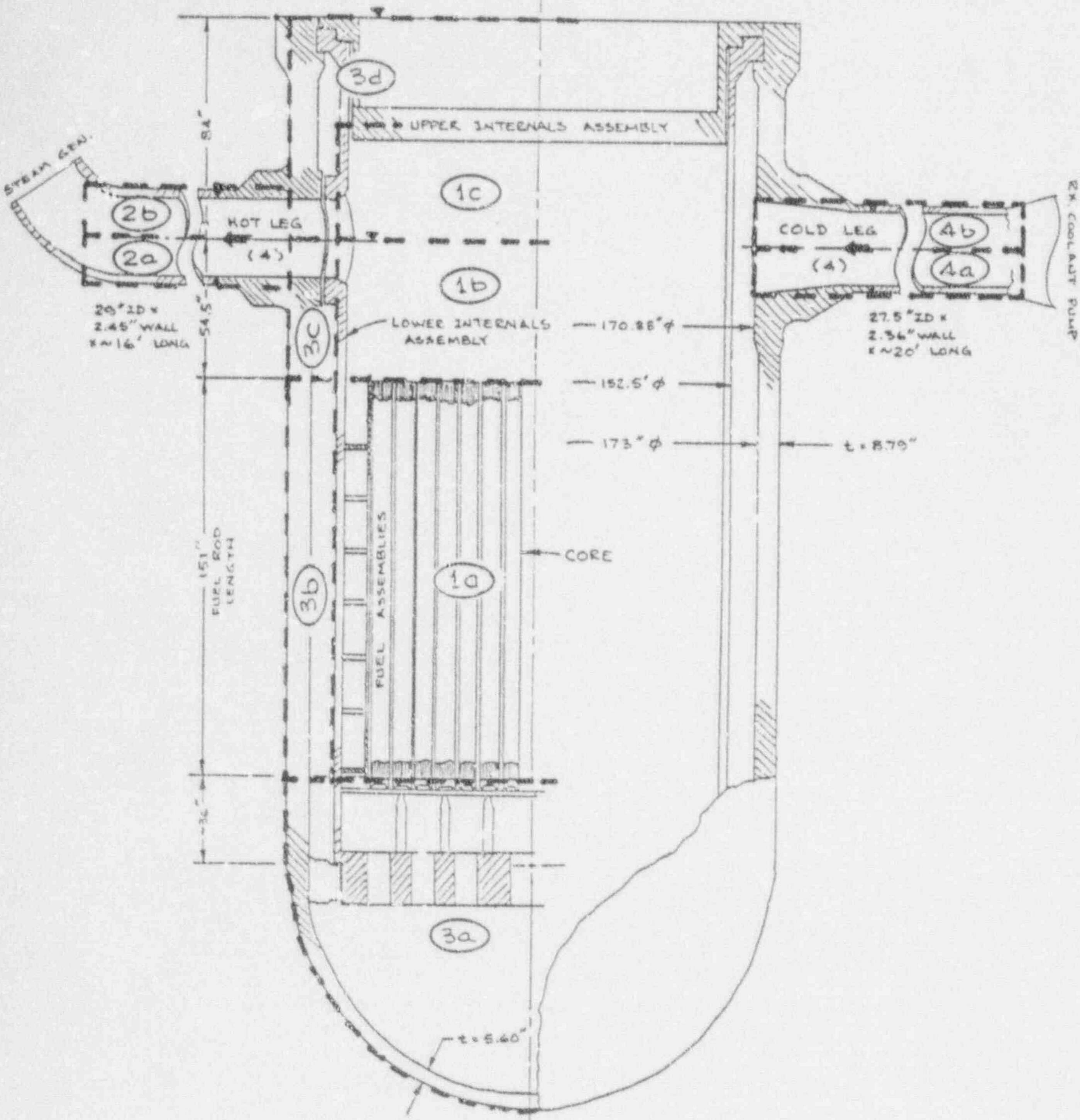


FIGURE B-8. WATER AND HEAT SINK VOLUME REGIONS

TABLE B-1. THERMOPHYSICAL PROPERTIES OF SOLID MATERIALS

Material	Density ($lbm/feet^3$)	Specific Heat (Btu/lbm-°F)	Reference
UO_2	--	0.059	B-2
Zircloy	--	0.081	B-2
Carbon Steel	487	0.11	B-3
Stainless Steel	493	0.12	B-3

The net free volume in region 1a is

$$1,596 - 170 - 489 = 937 \text{ ft}^3$$

and the total solid heat capacity is

$$(1.01 + 1.68) \times 10^4 = 26.9 \times 10^3 \text{ Btu/°F}$$

These summary net volume and solid heat capacity values are shown in Table B-2.

- Region 1b - Inside Core Barrel, above Core to Hot Leg Center Line. The total volume of this region is

  $$\pi/4 \times 152.5^2 \times 54.5/1,728 = 576 \text{ ft}^3$$

  The volume of lower internals assembly is

  $$0.15 \times 568 = 85 \text{ ft}^3$$

  with a solid heat capacity of

  $$85 \times 493 \times 0.12 = 5.0 \times 10^3 \text{ Btu/°F}$$

  Control rod drive shafts in this region are not considered. The net free volume is

  $$576 - 85 = 491 \text{ ft}^3$$

- Region 1c - Inside Core Barrel above Hot Leg Center Line. This region extends from the hot leg center line up to midplane of the upper internals assembly grid plate; this height is approximately 44 inches. The total weight of the upper internals assembly (from Westinghouse Drawing 701J731, Revision 1) is 132,000 lbm, corresponding to a volume of 268 cubic feet of austenitic stainless steel. The lower half of the upper assembly grid plate will be included as part of the solid heat capacity of region 1c, estimated to be 40% of the total volume, or 107 cubic feet. The total volume of region 1c is

  $$\pi/4 \times 152.5^2 \times 44/1,728 = 465 \text{ ft}^3$$

  The solid volume is

  $$107 + 0.1 \times 568 = 164 \text{ ft}^3$$

  with a solid heat capacity of

  $$164 \times 493 \times 0.12 = 9.7 \times 10^3 \text{ Btu/°F}$$

  The net volume of region 1c is

  $$465 - 164 = 301 \text{ ft}^3$$

TABLE B-2. FREE VOLUME AND SOLID HEAT CAPACITY DATA

Region		Free Volume* (feet^3)	Solid Heat** Capacity (Btu/°F)
1a	In Core	937	26.9×10^3
1b	Above Core - To HLCL†	491	5.0×10^3
1c	Above Core - Above HLCL	301	9.7×10^3
2a	Hot Legs - Below HLCL	183	3.7×10^3
2b	Hot Legs - Above HLCL	183	3.7×10^3
3a	Core Inlet Plenum	1,122	23.6×10^3
3b	Downcomer - Core Height	458	17.6×10^3
3c	Downcomer - Above Core To HLCL	165	6.4×10^3
3d	Upper Head - Above HLCL	496	22.7×10^3
4a	Cold Legs - Below HLCL	196	4.0×10^3
4b	Cold Legs - Above HLCL	196	4.0×10^3

*Free water volume.
**Metal and fuel.
†HLCL = hot leg center line.

- Region 2a - Lower Half of Hot Legs. From Drawing 1 RC-01-01, Revision 6, the hot leg pipes have a 29-inch inside diameter, a 2.45-inch wall thickness and are approximately 16 feet long. The length from the vessel weld prep to the core barrel outside diameter is approximately 4 feet. There are four hot legs made of austenitic stainless steel. The free volume is estimated as

  $$\pi \times (14.5/12)^2 \times 20 \times 0.5 \times 4 = 183 \text{ ft}^3$$

  The solid heat capacity is estimated as

  $$\pi \times 29/12 \times 20 \times 2.45/12 \times 0.5 \times 4 \times 493 \times 0.12 = 3.7 \times 10^3 \text{ Btu/°F}$$

- Region 2b - Upper Half of Hot Legs. This region is conservatively estimated as being the same as region 2a. In actuality, if the vessel water level is at the top of the vessel flange, water would extend into the steam generator lower inlet plenums and the lower regions of the tube bundle, as well as up the pressurizer surge line.

- Region 3a - Core Inlet Plenum. This region includes the free volume within the vessel below the active core. From Westinghouse Drawing 11573-171-004, Revision 1, the vessel inside diameter is 173 inches, the cylindrical wall thickness is about 8.8 inches (including the stainless steel clad), and the lower head wall thickness is about 5.6 inches (including clad). The free volume cylinder height is about 36 inches, and the lower hemisphere inside radius is 88.2 inches. The gross volume is

  $$(\pi/4 \times 173^2 \times 36 + 2/3 \times \pi \times 88.2^3)/1,728 = 1,321 \text{ ft}^3$$

  As noted earlier for region 1a, 35% of the lower internals assembly is estimated in region 3a, corresponding to a volume of

  $$0.35 \times 568 = 199 \text{ ft}^3$$

  and a solid heat capacity of

  $$199 \times 493 \times 0.12 = 11,800 \text{ Btu/°F}$$

  The net volume of region 3a is

  $$1,321 - 199 = 1,122 \text{ ft}^3$$

  The outer portions of the reactor vessel are insulated, and the inside surfaces are in contact with water. Heat transfer from the vessel to the water is by natural convection. Since it is not clear how quickly the thick metal walls will heat up, one-dimensional transient heat conduction/convection analyses are done for the 8.78-inch thick wall and the 5.6-inch thick lower head. Carbon steel density and specific heat values shown in Table B-1 were used and a thermal conductivity value of 27 Btu/hr-ft-°F was used (Reference B-3). The initial wall temperature is taken to be 140°F, and it was assumed that the water temperature adjacent to the inside surface instantly increased to and remained at 212°F. The natural convection heat transfer coefficient on the vertical wall was estimated to be

$$h = 60.6 \times \Delta T^{1/3}$$

(Reference B-5), where ΔT is the temperature difference between the heated water and the wall surface. The correlation for the lower head was taken to be the average of a vertical surface and a horizontal, above-heated surface, or

$$h = 49 \times \Delta T^{1/3}$$

The nondimensional heatup curves for the cylindrical wall and lower head are shown in Figure B-9. The thinner lower head region heats up more quickly even though its heat transfer coefficient is smaller. Taking a 1-hour heatup period as representative, the fractional heat added to the cylindrical and lower head walls equals about 79% and 92%, respectively; 75% and 90% values are used in these analyses. Thus, the equivalent solid heat capacity of the 36-inch long wall section is taken to be

$$(\pi/4 \times (190.6^2 - 173^2) \times 36/1,728 \times 487 \times 0.11 \times 0.75 = 4,200 \text{ Btu/°F}$$

The equivalent solid heat capacity of the lower head is taken to be

$$2 \times \pi \times 88.2^2 \times 5.6/1,728 \times 487 \times 0.11 \times 0.9 = 7,600 \text{ Btu/°F}$$

The total solid heat capacity is

$$11,800 + 4,200 + 7,600 = 23,600 \text{ Btu/°F}$$

- Region 3b - Downcomer Adjacent to Active Core. The free volume in this region is

$$\pi/4 \times (173^2 - 152.5^2) \times 151/1,728 = 458 \text{ ft}^3$$

The heat capacity and displaced water volume of the neutron panels located on the outer surface of the core barrel are not included; this is slightly nonconservative since the volumetric specific heat of stainless steel is about 59 Btu per cubic foot °F versus about 61 Btu per cubic foot °F for water. The solid heat capacity of the vessel wall fraction is

$$151/36 \times 4,200 = 17,600 \text{ Btu/°F}$$

- Region 3c - Downcomer Area - Top of Active Core to Hot Leg Center Line. The height of this region is about 54.5 inches. The free volume is

$$458 \times 54.5/151 = 165 \text{ ft}^3$$

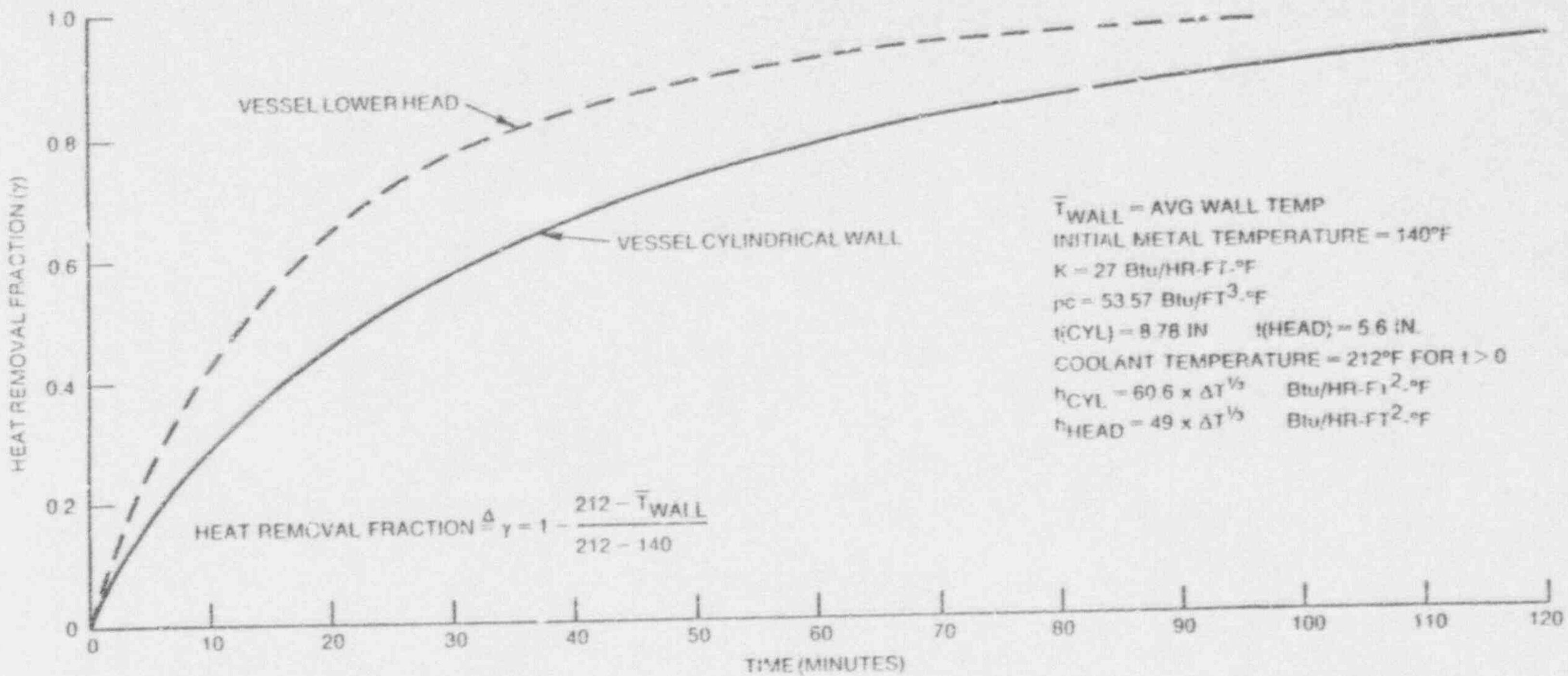


FIGURE B-9. VESSEL WALL AND LOWER HEAD HEATUP ANALYSIS

The solid heat capacity of the vessel wall fraction is

$$54.5/36 \times 4{,}200 = 6{,}400 \text{ Btu/°F}$$

- Region 3d - Upper Head and Downcomer above Hot Leg Center Line. This region includes the volumes of the upper downcomer and the region between the vessel flange and the upper internals assembly. The vessel inside diameter in this region is 170.88 inches. The free volume is

$$\pi/4 \times (170.88^2 - 152.5^2) \times 66/1{,}728$$

$$+ \pi/4 \times 141.3^2 \times 35/1{,}728 = 496 \text{ ft}^3$$

Solid heat capacities include 10% of the lower internals assembly, 60% of the upper internals assembly and 84 inches of the vessel wall. (The vessel wall thickness in this region is actually 10.75 inches, but the smaller heat capacity value for the thinner region will be used.) Thus, the solid heat capacity is

$$(0.1 \times 566 + 0.6 \times 268) \times 493 \times 0.12 + 84/36$$

$$\times 4{,}200 = 22{,}700 \text{ Btu/°F}$$

- Region 4a - Lower Half of Cold Legs. From Drawing 1-RC-03-01, Revision 6, the cold leg pipes have a 27.5-inch inside diameter and are 2.36 inches thick and about 20 feet long. The length from the vessel weld prep to the vessel inside diameter is about 3.7 feet. Water in the reactor coolant pump bowl and in the crossover pipe will be conservatively neglected. There are four cold legs made of austenitic stainless steel. The free volume is estimated as

$$\pi \times (13.75/12)^2 \times 23.7 \times 0.5 \times 4 = 196 \text{ ft}^3$$

The solid heat capacity is estimated as

$$\pi \times 27.5/12 \times 23.7 \times 2.36/12 \times 0.5 \times 4 \times 493$$

$$\times 0.12 = 4{,}000 \text{ Btu/°F}$$

- Region 4b - Upper Half of Cold Legs. This region will conservatively be estimated as being the same as region 4a. In actuality, if vessel water level is at the top of the vessel flange, water would fill the pump bowls and also extend up into the steam generator lower outlet plenums and tube bundles.

The free volumes and solid heat capacity values for the various regions shown in Figure B-8 are summarized in Table B-2. This information will be used to evaluate several heatup and boiloff scenarios described below.

B.1.3 ANALYSIS OF HEATUP AND BOILOFF WITH INTITIAL WATER LEVEL AT THE HOT LEG CENTER LINE

The initial conditions assumed for these analyses are:

- The vessel is filled with 140°F water, with the water level at the center line of the hot (and cold) legs. Prior to the time when decay heat removal is lost, it is assumed that the RHR system is operating, the water is uniformly well mixed at 140°F, and all solid heat sinks in contact with the water are also at 140°F.
- The volumes above the initial water level are vented in such a way that the boiloff process occurs at atmospheric pressure.
- Any steam that is boiled off is assumed to be lost from the system; that is, for this class of analyses, the steam generator secondary-side is assumed to be dry. Thus, no credit is claimed for any condensation on the steam generator tubes or an any other solid heat sinks above the initial water level and its condensate drainback into the reactor vessel.

When active decay heat removal is terminated, decay heat produced in the core begins to heat up the water within the core. Natural convection mechanisms rapidly heat the water immediately above the core and fairly quickly heat up the water in the hot legs; i.e., regions 1 and 2 quickly respond. Heat transfer from the heated water to the cooler water in the lower plenum, downcomer, and cold leg regions (i.e., regions 3 and 4) is slower. Two extreme cases are evaluated for the heatup phase: one case assumes complete thermal mixing between the hot and cold regions and the other case assumes no heat transfer at all between the two regions.

In the case with complete mixing, the water and solid heat capacities of regions 1a, 1b, 2a, 3a, 3b, 3c, and 4a are included. The total water volume, with initial level at the hot and cold leg center line, is 3,552 cubic feet, and the total solid heat capacity is 87,200 Btu/°F. The density of 140°F water is 61.4 lbm per cubic foot, so the initial water mass is 2.18×10^5 lbm and its equivalent sensible heat capacity (assuming C_p = 1.0 Btu/lbm-°F) is 2.18×10^5 Btu/°F. Figure B-7 shows decay heat values as a function of shutdown time for 1 and 18 months of prior continuous operation. It will be assumed that the plant has previously operated continuously at full power for 18-months, which is unlikely and conservative. Using the 18-month data, the decay heat curve can be approximated in the 1-day to 1-week shutdown time range as

$$Q/Q_o = .00501 \times t_{sd}(\text{days})^{-0.309}$$

where Q_o is the initial power equal to 3,411 MWt, or 1.16×10^{10} Btu/hour, and t_{sd} is the shutdown time in days. Thus,

$$Q = 5.83 \times 10^7 \times t_{sd}^{-0.309} \text{ Btu/hour}$$

The length of time to heat up the water and heat sinks to 212°F, defined as t_{hu}, is evaluated as

$$t_{hu} \text{ (hours)} = \frac{\sum wc}{Q} \cdot \Delta T = \frac{3.05 \times 10^5 \times (212 - 140)}{5.83 \times 10^7 \times t_{sd}(\text{days})^{-.309}}$$

$$= 0.377 \times t_{sd}(\text{days})^{0.309}$$

Thus, the heatup time for a 1, 3, and 7-day shutdown time is 0.4, 0.5, and 0.7 hours, respectively.

The next evaluation determines the length of time it takes to boil off the water above the top of the core. The void volume below the top of the core, composed of regions 1a, 3a, and 3b, is 2,517 cubic feet. Assuming this volume is filled with saturated liquid at 212°F (at a density of 58.8 lbm per cubic foot), the mass of water boiled off, W_{bo}, i

$$W_{bo} = 2.18 \times 10^5 - 2{,}517 \times 58.8 = 70{,}000 \text{ lbm}$$

The latent heat of vaporization at atmospheric pressure is 970.3 Btu/lbm, so the boiloff time, t_{bo}, is evaluated as

$$t_{bo} \text{ (hours)} = \frac{W_{bo} \times h_{fg}}{Q} = \frac{7 \times 10^4 \times 970.3}{5.83 \times 10^7 \times t_{sd}(\text{days})^{-.309}}$$

$$= 1.17 \times t_{sd}(\text{days})^{0.309}$$

and the time to core uncovery, t_{cu}, is

$$t_{cu} \text{ (hours)} = t_{hu} + t_{bo} = 1.55 \times t_{sd}(\text{days})^{0.309}$$

Thus, the length of time to core uncovery for the complete thermal-mixing case for a 1, 3, and 7-day shutdown time is 1.5, 2.2, and 2.8 hours, respectively.

A similar analysis of heatup and boiloff time intervals is done for the case in which the water level is initially at the hot leg center line, but there is no thermal mixing. The results of both analyses are presented in the form of banded curves as a function of shutdown time. The result of a simplified analysis to estimate the degree of heat transfer across the core barrel is also shown.

For the no thermal-mixing case, only regions 1a, 1b, and 2a are heated up. The water volume and mass and the solid heat capacities are

1,611 cubic feet, 98,900 lbm, and 35,600 Btu/°F, respectively. The heatup time is

$$t_{hu}\text{ (hours)} = \frac{1.345 \times 10^5 \times (212 - 140)}{5.83 \times 10^7 \times t_{sd}(\text{days})^{-0.309}} = 0.166 \times t_{sd}(\text{days})^{0.309}$$

The mass of water remaining in the vessel when water boils off to the top of the core is

$$937 \times 58.8 + (1,122 + 458) \times 61.4 = 1.52 \times 10^5 \text{ lbm}$$

Thus, the mass of water boiled off is

$$2.18 \times 10^5 - 1.52 \times 10^5 = 66,000 \text{ lbm}$$

This is somewhat less than in the complete-mixing case because of the higher density of the remaining downcomer and inlet plenum water. The boiloff time is evaluated as

$$t_{bo}\text{ (hours)} = \frac{6.6 \times 10^4 \times 970.3 + 1.6 \times 10^6}{5.83 \times 10^7 \times t_{sd}(\text{days})^{-0.309}} = 1.13 \times t_{sd}(\text{days})^{0.309}$$

where the second term in the numerator is the sensible heat addition to the water that enters the core during boiloff. The length of time to core uncovery is

$$t_{cu}(\text{hours}) = t_{hu} + t_{bo} = 1.30 \times t_{sd}(\text{days})^{0.309}$$

Thus, the length of time to core uncovery for the no thermal-mixing case for a 1, 3, and 7-day shutdown time is 1.3, 1.8, and 2.4 hours, respectively.

It is interesting to note that the heatup time is substantially less for the no-mixing case (relative to the complete-mixing case) because of the smaller water volume being heated, but the length of time to core uncovery is not markedly different since the mass of water boiled off is nearly the same in either case.

The results of these two analyses are shown in Figure B-1, which gives both heatup and boiloff times as a function of shutdown time. The information is shown in the form of bound curves, the lower bound value for no thermal mixing and the upper bound value for perfect mixing.

A separate transient analysis is done to estimate the degree of heat transfer across the core barrel due to conduction through the stainless steel (which has low thermal conductivity) and to natural convection on both surfaces. The model assumes that the heat transferred across the core barrel heats the downcomer and cold leg water and solid heat sinks, but not the lower plenum, which probably is not very effectively heated; e.g., natural convection transfers heat upward, not downward. The downcomer region only heats up 15°F in the first hour and 35°F in the first 3 hours (relative to an initial temperature difference taken to be being 72°F). Therefore, we have noted our best estimate values in Figure B-1, giving little credit for the complete thermal-mixing values at short time intervals.

B.1.4 ANALYSIS OF HEATUP AND BOILOFF WHEN INITIAL WATER LEVEL IS AT THE VESSEL FLANGE

A similar heatup and boiloff analysis is now done, assuming that the initial water level is at the vessel flange. The total water volume and solid heat capacity are 4,728 cubic feet and 127,300 Btu/°F, respectively. As noted earlier, no credit is claimed for water in the steam generator plena or tubes or for water in the pressurizer surge line. The initial water temperature is taken to be 140°F, and its mass is 2.90×10^5 lbm. We first assume complete thermal mixing. The heatup time is

$$t_{hu}(\text{hours}) = \frac{4.17 \times 10^5 \times (212 - 140)}{5.83 \times 10^7 \times t_{sd}(\text{days})^{-0.309}} = 0.515 \times t_{sd}(\text{days})^{0.309}$$

The mass of water boiled off is

$$2.90 \times 10^5 - 1.48 \times 10^5 = 1.42 \times 10^5 \text{ lbm}$$

so the boiloff time is

$$t_{bo}(\text{hours}) = \frac{1.42 \times 10^5 \times 970.3}{5.83 \times 10^7 \times t_{sd}(\text{days})^{-0.309}} = 2.36 \times t_{sd}(\text{days})^{0.309}$$

and the length of time to core uncovery is

$$t_{cu}(\text{hours}) = t_{hu} + t_{bo} = 2.88 \times t_{sd}(\text{days})^{0.309}$$

This corresponds to core uncovery times of 2.9, 4.0, and 5.3 hours for 1, 3, and 7-days shutdown times, respectively.

For the nonthermal-mixing case, the heated water volume, water mass, and solid heat capacities are 2,095 cubic feet, 1.28×10^5 lbm, and 49,000 Btu/°F, respectively. The heatup time is

$$t_{hu}(\text{hours}) = \frac{1.77 \times 10^5 \times (212 - 140)}{5.83 \times 10^7 \times t_{sd}(\text{days})^{-0.309}} = 0.219 \times t_{sd}(\text{days})^{0.309}$$

The mass of water boiled off is

$$2.90 \times 10^5 - 1.52 \times 10^5 = 1.38 \times 10^5 \text{ lbm}$$

The boiloff time is

$$t_{bo}(\text{hours}) = \frac{1.38 \times 10^5 \times 970.3 + 4.65 \times 10^6}{5.83 \times 10^7 \times t_{sd}(\text{days})^{-0.309}} = 2.38 \times t_{sd}(\text{days})^{0.309}$$

where the second term in the numerator is the sensible heat added to the water entering the core from outside the core barrel during boiloff. The time to core uncovery is

$$t_{cu}(\text{hours}) = t_{hu} + t_{bo} = 2.60 \times t_{sd}(\text{days})^{0.309}$$

This corresponds to core uncovery times of 2.6, 3.6, 4.7 hours for 1, 3, and 7-day shutdown times, respectively.

The length of time to heat up the water to 212°F and the length of time to boil off the level to the top of the core are shown in Figure B-2 for the complete and for the no thermal mixing cases. A heat transfer analysis similar to that described earlier that accounts for the added surface area and water masses was done. Again, heat transfer from the hot water inside the core barrel to the cooler downcomer water and the water above the upper internals plate is slow. At 2 hours, the heating is about 30% effective; at 5 hours, it is about 60% effective. Our best estimate curves are noted in the figures.

B.1.5 FUEL ROD HEATUP TRANSIENT DURING CORE UNCOVERY

The previous analyses evaluate the length of time it takes to begin core uncovery for various initial water levels and the time after reactor shutdown when shutdown cooling is lost. Next, the fuel rod temperature transient after core uncovery begins is analyzed. The case analyzed is for an initial water level at the hot leg center line, 140°F initial water temperature, shutdown cooling lost 3 days after shutdown, and complete thermal mixing of the water.

Steam cooling of the uncovered portion of the fuel rods and the fuel rod heat capacity are modeled. A 1.21 fuel assembly radial peaking factor (from FSAR Figure 4.3-9) and the midcycle axial power shape from FSAR Figure 4.3-17 are used. The results of this analysis are shown in Figure B-3. Core uncovery begins at around 2.2 hours, and severe clad oxidation begins at around 4.1 hours. The fuel rod adiabatic heatup rate is around 3,000°F per hour, so steam cooling is quite effective in delaying the heatup process. Severe clad oxidation would not occur until about 2 hours after core uncovery begins. If core outlet thermocouples are operable, the operators would be aware of core uncovery and have more than 2 hours for recovery action.

A similar evaluation has been made with the initial water level at the location where the RHR system takes suction from the cold leg. In this case, core uncovery begins at 1.5 hours (versus 2.2 hours in Figure B-3), but the heatup curve should be parallel to that shown in Figure B-3.

B.2 LOSS OF DECAY HEAT REMOVAL AND SUBSEQUENT VESSEL PRESSURIZATION AND INVENTORY LOSS THROUGH RHR RELIEF VALVES

In this scenario, the reactor coolant system is closed, the plant has been shut down for several days and is on closed loop RHR cooling, the average RCS water temperature is 270°F, the steam generator shell sides are dry, and the pressurizer water level and pressure are 70% (wide range) and 300 psig, respectively. The scenario begins with loss of shutdown cooling; the time to "squeeze" the pressurizer bubble to the 500-psig RHR setpoint pressure, the time to "squeeze" the nitrogen cover gas in the pressurizer relief tank (PRT) to the 100-psig rupture disc failure pressure, and the subsequent vessel pressurization and level reduction are evaluated. The RHR relief valve begins opening at 450 psig, is fully open at 500 psig, and has a liquid relief capacity of 990 gpm at 500 psig and 2,100 gpm at 2,250 psig (i.e., flow is porportional to the square root of the pressure difference). The RHR relief valve discharges into the PRT, which is assumed to be 60% full of water with a 3-psig nitrogen cover gas pressure. The total PRT volume is 1,800 cubic feet. The plant protection logic isolates the RHR system (including its relief valve) if vessel pressure exceeds 660 psig after which the pressurizer PORVs control pressure. As part of the low temperature overpressure protection (LTOP) control, the PORV setpoint pressure is automatically changed, with a measured water temperature signal (T_W) as

$$P_{setpoint} = 376.3 + 5.42 \times e^{0.01736 \times T_W} \text{ psig}$$

with the restriction that $480 < P_{setpoint} < 2,385$ psig. One PORV receives an auctioneered signal from the cold leg temperature sensors, and the other PORV receives one from the auctioneered hot leg temperature sensors. With the RCS filled with water, some natural convection flow is expected (even though the steam generator secondary sides are assumed to be dry in these analyses), so the hot and cold leg temperatures are not expected to be significantly different. The setpoint pressure remains higher than the saturation pressure, so the PORVs do not open until vessel pressure reaches 2,385 psig. The PORVs have a setpoint pressure of 2,385 psig and a saturated steam-relieving capacity of 2.1×10^5 lbm/hour for each (of two) valves. The energy removal capacity of one PORV (approximately 0.7% of core-rated thermal power) far exceeds the decay heat levels, so the PORV will most likely cycle.

Many of the reactor coolant system volumes and solid heat capacities are shown in Table B-2. In this configuration, water is also initially in the pressurizer, the pressurizer surge line, the steam generator tubes and inlet/outlet plena, and in the reactor coolant pump bowl and the crossover legs. These volumes (from Reference B-7) are:

- Vessel Head = $2/3 \times \pi \times (83.5/12)^3$ = 706 Cubic Feet
- Pressurizer and Surge Line = 1,848 Cubic Feet (total)
- Steam Generator Tube Bundle (primary) = 2,784 Cubic Feet

- Steam Generator Plena, Crossover Legs, and Pump Bowls = 1,912 Cubic Feet

Solid heat capacities associated with the above regions of the RCS will be conservatively neglected since, because they are in the higher elevations, they will be the first to void as water is lost from the system.

The total initial water volume in the system is 11,400 cubic feet and the total solid heat capacity (from Table B-2) is 1.27×10^5 Btu°F. The density of 270°F water is 58.24 lbm per cubic foot, so the mass of water initially in the RCS is 6.64×10^5 lbm. The steam bubble volume is 550 cubic feet. As noted in Section B.1, the core decay heat (in Btu per hour) is $5.83 \times 10^7 \times t_{sd}(\text{days})^{-0.309}$.

When shutdown cooling is lost, the water in the RCS will begi to heat up and swell, squeezing the steam dome in the pressurizer. Treating the steam dome compression as an a abatic process, the volume change to increase pressure from its ini ial volume of 300 psig to the 500-psig RHR relief valve setpoint is evaluated as

$$315 \times 550^{1.3} = 515 \times V_2^{1.3}$$

$$V_2 = 377 \text{ ft}^3$$

$$\Delta V = 550 - 377 = 173 \text{ ft}^3$$

The change in liquid density is

$$58.241 \times 11{,}400/(11{,}400 + 173) = 57.37 \text{ lbm/ft}^3$$

corresponding to an average liquid temperature of 297°F. The energy addition to the water and solid heat capacities required for this 27°F temperature rise is

$$(6.64 \times 10^5 + 1.27 \times 10^5) \times 27 = 2.14 \times 10^7 \text{ Btu}$$

Thus, the length of time to increase vessel pressure to 500 psig for 1, 3, and 7-day shutdown times is 22, 31, and 40 minutes, respectively. Further heatup of the RCS causes some liquid relief from the RHR relief valve to accommodate the thermal swell, but sustained liquid flow does not begin until the vessel water heats up to the saturation temperature that corresponds to a setpoint pressure of 515 psia, or 470°F, or a total temperature increase of 200°F. This corresponds to an energy addition of 1.58×10^8 Btu. The time after the loss of shutdown cooling, when there is sustained relief valve flow for the 1, 3, and 7-day shutdown times, is 2.7, 3.8, and 4.9 hours, respectively. When the water heats up to 470°F, the vessel contains about $(11{,}600/.0198) = 5.86 \times 10^5$ lbm of water saturated at 515 psia. Thus, about $6.64 \times 10^5 - 5.86 \times 10^5 = 78{,}000$ lbm of water is squeezed out of the RHR safety valve. The average water leakage rate out the valve ranges from about 60 gpm for a 1-day shutdown time to about 30 gpm for a 1-week shutdown time. This is substantially less than the 990-gpm valve capacity at 500 psig, so the RHR relief valve is only intermittently opened.

The water released through the RHR relief valve is discharged to the PRT, which contains about 1,080 cubic feet (or 67,000 lbm) of water and has a cover space of 720 cubic feet of nitrogen at 3 psig. Assuming that the cover gas volume is adiabatically compressed as water is added, the compressed volume at the 100-psig rupture disc failure pressure is $[(18/115)^{1/1.4} \times 720] = 191$ cubic feet, or about 530 cubic feet of water must be added. The water released through the RHR relief valve is heated, initially being about 300°F (with a density of about 57.3 lbm per cubic foot). The water mass added to the PRT to pop the rupture disc is about (530 x 57.3) = 30,000 lbm, so the disc is expected to rupture within about 1 to 2 hours for the 1-day and 1-week shutdown times respectively.

The remaining part of the scenario becomes more difficult to analyze. With the average RCS temperature at saturation for the 500-psig RHR system relief valve setpoint, further decay heat addition boils water, creates steam bubbles in the upper part of the RCS (e.g., the vessel head, the pressurizer, and steam generator tubes), and forces liquid out the relief valve. If vessel pressure remains below the 660-psi RHR isolation pressure, liquid flow out the RHR relief valve continues until the liquid-vapor interface drops below the elevation where the RHR lines connect to the hot and cold legs. At this time, leakage changes to saturated steam. Part of the problem is that the capacity of the RHR relief system is not so large, thus, vessel pressure rises above the 500-psi setpoint. To analyze this transient, a PLG computer code used to analyze RHR transients has been modified to Seabrook conditions. The code models the RCS volume, and core and vessel heat capacities are accounted for. The leakage rate out the RHR relief valve is saturated liquid until the water level drops to the RHR line connections. At that time, the leak rate is converted to saturated vapor flow using the Moody critical flow correlations. The effective valve area is evaluated on the basis of a (saturated) liquid flow of 2,100 gpm (room temperature density of 8.34 lbm per gallon assumed) at a pressure of 2,250 psi. If RHR system isolation occurs, the pressure has to increase to the pressurizer PORV setpoint of 2,385 psig. The PORV-saturated steam-relieving capacity is 2.1×10^5 lbm per hour, which corresponds to a saturated steam energy removal rate of about 0.7% decay heat, so the PORV intermittently opens and recloses if the RHR system is isolated.

The plant response to these scenarios is evaluated for a 1-day and a 3-day shutdown time; the results are shown in Figures B-4 and B-5. Note that the time to core uncovery is appreciably extended if the RHR system is isolated on high pressure. This is due to the sensible heat required to heat the water and solids up to the 2,385-psig saturation temperature, and that energy is more efficiently relieved by vapor release than by liquid release.

B.3 DELAY IN CORE HEATUP FROM STEAM GENERATOR INVENTORY BOILOFF

The previous section analyzes the plant response following a loss of RHR cooling when the vessel is full of water and the steam generators are dry. This section assesses the delay in the transient because of steam generator boiloff.

The scenario to be analyzed follows: the RHR system is initially operating with the RCS full (i.e., the pressurizer is partly full, with a system pressure at approximately 300 psig), and the average RCS water temperature is 200°F. Two steam generators have water on the secondary side at the 17% narrow-range level, and their atmospheric dump valves are set to open at 150 psig; the remaining two steam generators have no secondary water. The two filled steam generators are not initially removing energy from the systems and are at the 200°F initial temperature. RHR cooling is assumed to be lost at various times (ranging from 1 day to 1 week) after shutdown.

The average steam generator secondary water temperature is 200°F, the volume of water on the secondary side with the narrow-range level at 17% is 3,150 cubic feet per steam generator, and the weight of the Inconel 600 tube bundles is estimated to be 96,000 lbm per steam generator. The density of water at 200°F is 60.1 lbm per cubic foot, so the initial mass of water in the two steam generators is 378,000 lbm. When RHR cooling is lost, the water in the core begins to heat up, resulting in natural convection flow through the two filled steam generators. Because of the low decay heat levels in the core and the large heat transfer area in the steam generators, the secondary water heats up and boils off at the 150-psig dump valve pressure (corresponding to a saturation temperature of 366°F). It is assumed that steam generator heat removal ceases when the liquid level gets to within 2 feet of the tube sheet (i.e., there is insufficient heat transfer area at this condition); this corresponds to around 140 cubic feet of liquid per steam generator. The estimated secondary volume of each steam generator is 5,000 cubic feet, so the mass of saturated water and steam remaining when heat removal ceases is (140 x 2 x 54.9) = 15,000 lbm and (5,000 x 2 x 0.362) = 3,600 lbm, respectively. The total energy removed by the secondary water in the two steam generators is evaluated as follows:

- Heat Water from 200°F to 366°F

  3.78 x 1[illegible] x 170.5 = 64.4×10^6 Btu

- Boil Water at 366°F (150 psig)

  $(3.78 - 0.15 - 0.04) \times 10^5 \times 857.1 = 307.7 \times 10^6$ Btu

- Heat Up Tube Bundles from 200°F to 366°F

  $2 \times 9.6 \times 10^4 \times 0.11 \times 166 = 3.5 \times 10^6$ Btu

The total energy is 3.75×10^8 Btu. As discussed in Section B.1.3, the decay heat rate expressed in time after shutdown (t_{sd}, in days) is

$$Q = 5.83 \times 10^7 \times t_{sd}^{-0.309} \text{ Btu/hour}$$

Thus, the time delay afforded by the steam generators, T_{SGD} (hours), is evaluated as

$$T_{SGD}(\text{hours}) = \frac{3.75 \times 10^{8} \text{ Btu}}{5.83 \times 10^{7} \times t_{sd}^{-0.309} \text{ Btu/hour}} = \frac{6.43 \text{ hours}}{t_{sd}^{-0.309}}$$

Thus, the delays in RCS heatup for 1, 3, and 7-day shutdown times are 6.4 hours, 9.0 hours, and 11.7 hours, respectively. A curve of the steam generator dryout time as a function of shutdown time is shown in Figure B-6. After the steam generators dry out, it is conservative to use the heatup and core uncovery times described in Section B.2 (this is conservative since no credit is claimed for heating up the RCS from 200°F to the 270°F initial temperature assumed in Section B.2).

B.4 VESSEL VENTING TO ALLOW RWST GRAVITY MAKEUP TO THE VESSEL

These scenarios evaluate the adequacy of certain vent paths to limit the vessel backpressure to allow gravity flow (after the operator opens a closed valve) of RWST water into vessel. Two RWST water levels are to be considered:

- 24,500 gallons above "empty" (th echnical specification low limit).
- RWST full.

The various elevations are shown in Figure B-10. Two vent paths are initially considered: (1) a 2-inch globe valve in a line from the pressurizer plus three orificed lines (each with a 3/8-inch orifice, two on the pressurizer and one on the vessel head) and (2) same as the case above plus a 1-inch globe valve in line from vessel head. As shown below, these vents are not very effective, so a third vent configuration is also evaluated.

The analysis approach evaluates the vessel dome pressure that only allows gravity drain of the RWST for the two levels considered. The saturated steam mass flow through the two vent configurations is evaluated, and the corresponding energy flow is equated to decay heat values to determine the required shutdown time. Decay heat as a function of shutdown time is shown in Figure B-7. With water level at the hot leg center line, the hydrostatic pressure difference due to saturated steam is insignificant, so vent location is not important.

B.4.1 VENT FLOWS AND ENERGY REMOVAL WHEN THE RWST IS FILLED WITH 24,500 GALLONS OF BORATED WATER

The RWST hydrostatic head pressure is

P = (23 feet 9 inches + 7 feet + 8 feet 10 inches) x 62.4/144
= 17.1 psi

Thus, the vessel pressure must be slightly below (14.7 + 17.1) = 31.8 psia to allow the RWST to gravity drain. The frictional pressure drop in the RWST line is negligible. Vent line flow rates are evaluated

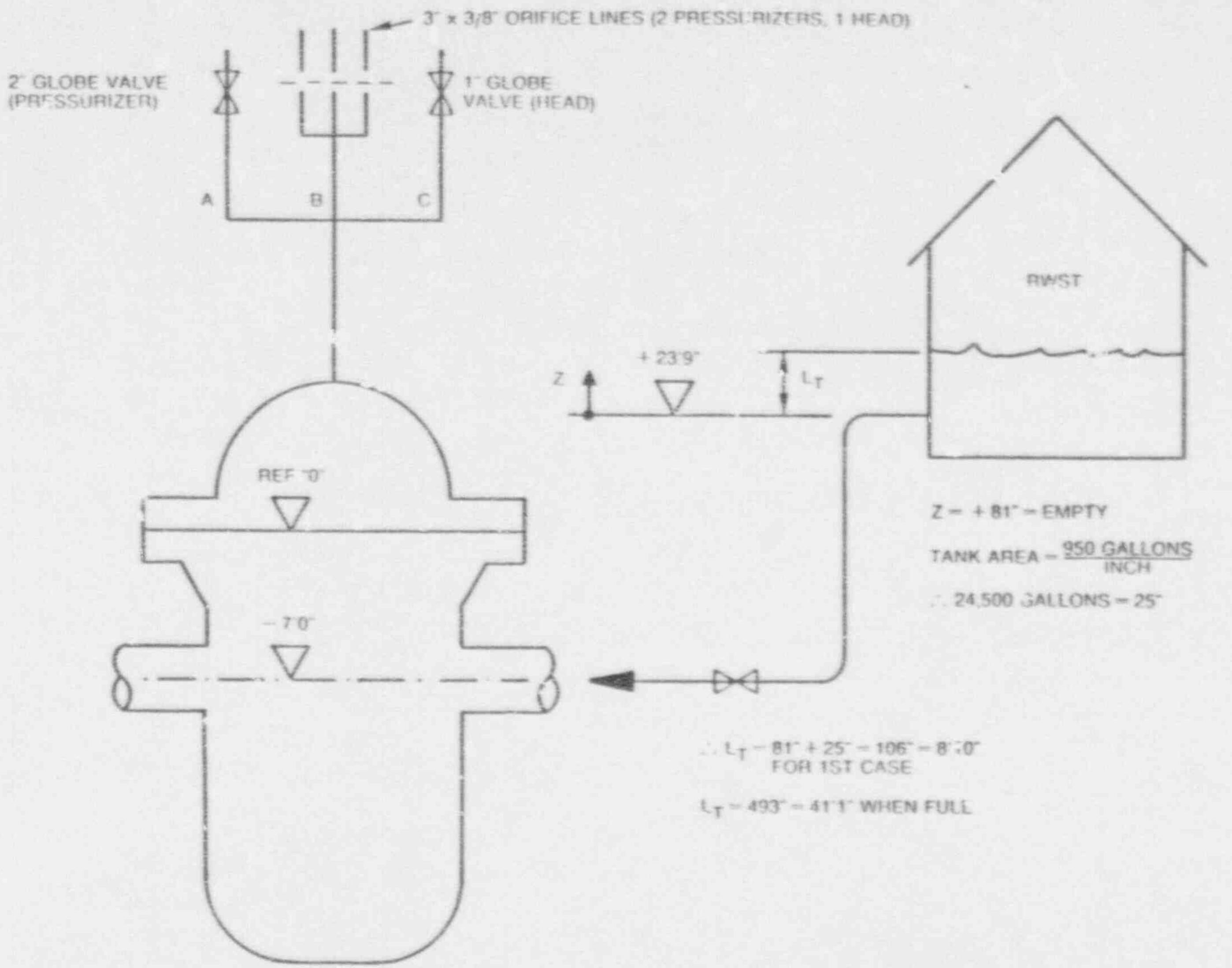


FIGURE B-10. REFUELING WATER STORAGE TANK AND REACTOR COOLANT SYSTEM ELEVATION DIFFERENCES using Reference B-6. The vents are assumed to discharge to atmospheric pressure (14.7 psia). Saturated steam conditions at 31.8 psia are

v_g = 13.0 ft^3/lbm

T = 254°F

h_g = 1,165.4 Btu/lbm

- Flow through 2-Inch Globe Valve. From page A-30 of Reference B-6, the L/D of a conventional globe valve is between 340 and 450. The larger valve is used, and it is assumed that there are no pressure losses in the piping system. Assuming a Schedule 160 2-inch pipe, f = .02 from page A-25 of Reference B-6; therefore,

$$K_{Total} = K_W + K_{Valve + Piping} + K_{Out}$$

$$= 0.5 + 450 \times .02 + 1.0 = 10.5$$

If flow through the vent is subsonic,

$$\Delta P = 31.8 - 14.7 = 17.1 \text{ psi}$$

and

$$\Delta P/P_1' = 17.1/31.8 = 0.538$$

From page A-22 of Reference B-6 for saturated steam (k = 1.3), Y = 0.79, and the vent is not choked. For the 2-inch Schedule 160 line,

$$d_i = 1.689 \text{ inches}$$

The line flow is

$$\dot{m} = 1{,}891 \cdot Y \cdot d_i^2 \sqrt{\frac{\Delta P}{K v_g}}$$

$$= 1{,}891 \times 0.79 \times 1.689^2 \times \sqrt{\frac{17.1}{10.5 \times 13.0}} = 1{,}510 \text{ lbm/hr}$$

- Flow through 1-Inch Globe Valve. As before,

K_{Total} = 10.5

Y = 0.79

ΔP = 17.1

but

$d_i = 0.815$

$$\dot{m} = 1,891 \times 0.79 \times 0.815^2 \times \sqrt{\frac{17.1}{10.5 \times 13.0}} = 350 \text{ lbm/hr}$$

- Flow through Orifice Lines. From page ?-14 of Reference B-6, the flow of compressible fluids through an orifice is evaluated as

$$q = YCA \cdot \sqrt{\frac{2g\ (144) \cdot \Delta P}{\rho}}$$

For saturated steam, k = 1.3. Assume that the orifice is in "large" pipe (2 inches is large) and that the Reynolds number is large, C = 0.6, from page A-19 of Reference B-6. From page A-21 of Reference B-6, the critical pressure ratio (r_c) is 0.545, so

$$\Delta \quad = P_1 \times (1 - r_c) = 31.8 \times (1 - 0.545) = 14.5$$

$$\Delta P/P_1' = 0.455$$

From page A-20 of Reference B-6, Y = 0.86. Thus,

$$\dot{q} = 0.86 \times 0.6 \times \frac{\pi}{4} \times \left(\frac{.375}{12}\right)^2 \times \sqrt{\frac{2 \times 32.2 \times 144 \times 14.5}{1/13.0}}$$

$$= 0.52 \ \frac{ft^3}{sec}$$

or

$$\dot{m} = \rho \dot{q} = 0.52 \times 3,600 \times 1/13 = 145 \text{ lbm/hr-orifice}$$

- Energy Removal for 2-Inch Globe Valve plus 3 x 3/8-Inch Orifice Lines. Here,

Total Flow Rate = 1,510 + 3 x 145 = 1,945 lbm/hr

The energy removal capability of the various vent path combinations is evaluated by multiplying the vent flow rate by the change in enthalpy of the incoming RWST water (H = 38 Btu/lbm) and the saturated steam, which is vented (H = 1,165.4 Btu/lbm).

$$\text{Energy Removal} = 1,945 \ \frac{lbm}{hr} \times 1,127.4 \ \frac{Btu}{lbm} = 2.19 \times 10^6 \ \frac{Btu}{hr}$$

$$= 0.64 \text{ MWt} = 0.02\% \text{ decay heat}$$

From Figure B-7, it is apparent that these small vent lines have insufficient venting capacity for the low RWST level case.

B.4.2 VENT FLOWS AND ENERGY REMOVAL WHEN RWST IS FULL

The RWST hydrostatic pressure, when it is full, is

$$P = (23 \text{ feet } 9 \text{ inches} + 7 \text{ feet} + 41 \text{ feet } 1 \text{ inch}) \times 62.4/144$$
$$= 31.4 \text{ psi}$$

The vessel pressure therefore is (31.4 + 14.7) = 46 psia or less to allow gravity fill to begin. Saturated steam conditions are

$$v_g = 9.209 \text{ ft}^3/\text{lbm}$$

$$T = 276°F$$

$$h_g = 1,172.4 \text{ Btu/lbm}$$

- <u>Flow through 2-Inch Globe Valve.</u>

  K = 10.5 (as before).

  If flow is subsonic,

  $$\Delta P/P_1' = 31.4/46 = 0.68$$

  From Reference B-6, page A-22, Y = 0.73 and line is unchoked. The line flow is

  $$1,891 \times 0.73 \times 1.689^2 \times \sqrt{\frac{31.4}{10.5 \times 9.209}} = 2,240 \text{ lbm/hr}$$

- <u>Flow through 1-Inch Globe Valve.</u> Flow is

  $$2,240 \times (0.815/1.689)^2 = 520 \text{ lbm/hr}$$

- <u>Flow through Orifice Lines.</u> Same as earlier, except

  $$\Delta P = 46 \times (1 - 0.545) = 20.9$$

  $$\dot{Q} = 0.86 \times 0.6 \times \frac{\pi}{4} \times \left(\frac{.375}{12}\right)^2 \times \sqrt{\frac{2 \times 32.2 \times 144 \times 20.9}{1/9.209}} = 0.53 \frac{\text{ft}^3}{\text{sec}}$$

  $$\dot{m} = 0.53 \times 3600/\ 9.209 = 210 \text{ lbm/hr orifice}$$

- <u>Energy Removal with All Vents Open.</u>

  $$\dot{m}_{Total} = 2,240 + 520 + 3 \times 210 = 3,390 \text{ lbm/hr}$$

  $$\dot{E}_{Total} = \dot{m}_{Total} \times \Delta h = 3.84 \times 10^6 \frac{\text{Btu}}{\text{hr}} = 1.13 \text{ MWt}$$

  $$= 0.033\% \text{ decay heat}$$

This is still impractical. A final vent configuration considers the case wherein a single pressurizer safety valve is removed and the line is left open.

B.4.3 FLOW THROUGH PRESSURIZER SAFETY VALVE LINE WITH SAFETY VALVE REMOVED

The pressurizer safety valve line is approximately 7 feet long and is a 6-inch, Schedule 160 pipe (Reference B-7); the inside diameter is 5.189 inches.

$$\frac{L}{D} = \frac{7 \times 12}{5.189} = 16.2$$

and

$f = .016$ (per page A-25 of Reference B-6)

$K = 0.5 + .016 \times 16.2 + 1 = 1.76$

For the case when the RWST is full,

$\Delta P/P = 31.4/46 = 0.68$

From page A-22 of Reference B-6, $(\Delta P/P_1)_{max} = 0.57$, so line is choked. Thus,

$\Delta P = 46 \times 0.57 = 26.2$ psi

$Y = 0.63$

and the mass flow out the line is

$$m = 1,891 \times 0.63 \times 5.189^2 \times \sqrt{\frac{26.2}{9.209 \times 1.76}} = 40,800 \text{ lbm/hr}$$

The energy removal rate is evaluated as

$$\dot{E} = \dot{m}\Delta h = 40,800 \times 1,134.4 = 4.63 \times 10^7 \text{ Btu/hr} = 13.6 \text{ MWt} = 0.40\% \text{ power}$$

This is the decay heat at about 48 hours after shutdown.

For the case when the RWST water volume is 24.5 kgal above empty and the safety valve line is open,

$\Delta P/P_1' = 17.1/31.8 = 0.538$

which is less than 0.57, so line is not choked. $Y = 0.66$ Flow is

$$\dot{m} = 1,891 \times 0.66 \times 5.189^2 \times \sqrt{\frac{17.1}{1.76 \times 13.0}} = 2.9 \times 10^4 \text{ lbm/hr}$$

$$\dot{E} = 2.9 \times 10^4 \times 1{,}127.4 = 3.3 \times 10^7 \frac{Btu}{hr} = 9.7 \text{ MWt} = 0.28\%$$

= decay heat at 140 hours

A final case to be considered is to find the line size with a fully open globe valve that would allow a full RWST to gravity drain 7 days after shutdown. From Section B.4.1, K = 10.5 and $\Delta P/P = 31.4/46$ when RWST is full. The decay heat 7 days (168 hours) after shutdown is 0.27%, or the required steam flow is

$$\dot{m}_{req'd} = \frac{\dot{Q}}{h} = \frac{0.0027 \times 3{,}411 \times 3.412 \times 10^6}{1{,}134.4} = 2.77 \times 10^4$$

The pipe/valve size is evaluated as

$$d^2 = \frac{2.77 \times 10^4}{1{,}891 \times 0.73 \times \sqrt{\frac{31.4}{10.5 \times 9.209}}} = 35.2$$

$$d = 5.93 \text{ inches}$$

This indicates that an 8-inch, Schedule 160 line (d = 6.813) with an open globe valve is adequate.

B.5 REFERENCES

B-1. American Nuclear Society, "American National Standard for Decay Heat Powers in Light Water Reactors," the American Nuclear Society Standards Working Group, ANSI/ANS-5.1-1979, August 29, 1979.

B-2. El-Wakil, M. M., "Nuclear Power Engineering," McGraw-Hill Book Company, New York, 1962.

B-3. Materials In Design Engineering, Materials Selector Issue, Vol. 54, No. 5, October 1961.

B-4. Keenan, J. H., and F. G. Keyes, "Thermodynamic Properties of Steam," First Edition, 22nd Printing, John Wiley and Sons, New York, November 1950.

B-5. Brown, A. I., and S. M. Marco, "Introduction to Heat Transfer," Third Edition, McGraw-Hill Book Company, New York, 1958.

B-6. Crane Company, "Flow of Fluids Through Valves, Fittings, and Pipes," Technical Paper 410, Chicago, 1957.

B-7. Casey, T. J., New Hampshire Yankee, personal communication, November 1987.

APPENDIX C

SUMMARY OF SHUTDOWN TECHNICAL SPECIFICATIONS FOR MODES 4, 5, AND 6

APPENDIX C

Table C-1 contains a summary of the important Technical Specifications that are applicable during shutdown Modes 4, 5, and 6. For more details, see the "Seabrook Station Technical Specifications", NUREG-1207 (October 1986).

TABLE C-1: SUMMARY OF SHUTDOWN TECHNICAL SPECIFICATIONS - FOR MODES 4, 5, AND 6

FUNCTION	OPERABILITY REQUIREMENTS		
	MODE 4 (Hot Shutdown)	MODE 5 (Cold Shutdown)	MODE 6 (Refueling)
Borated Injection Flow Path	Boric Acid Storage Tank (22,000/gal.) and Transfer Pump and Charging Pump or RWST (477,000/gal.) and Charging Pump [3.1.2.1, 3.1.2.6]	Boric Acid Storage Tank (6,500/gal.) and Transfer Pump and Charging Pump or RWST (24,500/gal.) and Charging Pump [3.1.2.1, 3.1.2.5]	Same as Mode 5
Core Cooling Loop	Two Core Cooling Loops operable (and one operating) (1) Two RC Loops including S/Gs and RCPs, or (2) two RHR Loops, or (3) one RC Loop and one RHR Loop. Also, all 4 ARVs operate if S/Gs are used for decay heat removal. No requirement for EFW. [3.4.1.3, 3.7.1.6]	One RHR Loop Operating and Either (1) the other RHR Loop operable or (2) two S/Gs with Level > 17% [3.4.1.4] With RC Loops Drained, One RHR Loop Operating and One RHR Loop operable. [3.4.1.4]	With Water Level > 23/ft. Above Vessel Flange, One RHR Loop in Operation. [3.9.8.1] With Water Level < 23/ft. Above Vessel Flange, Two RHR Loops, One Loop in Operation [3.9.8.2]
ECCS Equipment	One ECCS Subsystem operable: Charging Pump, RHR Pump, and Heat Exchanger, and Flow Path from RWST and from sump to RCS. [3.5.3.1] Accumulators Isolated [3.5.1.2]	SI Pumps Inoperable, Accumulators Isolated [3.5.3.2, 3.5.1.2]	SI Pumps Inoperable [3.5.3.2]

TABLE C-1: SUMMARY OF SHUTDOWN TECHNICAL SPECIFICATIONS - FOR MODES 4, 5, AND 6

FUNCTION	OPERABILITY REQUIREMENTS		
	MODE 4 (Hot Shutdown)	MODE 5 (Cold Shutdown)	MODE 6 (Refueling)
Overpressure Protection	Either - (1) 2 RHR Suction Relief Valves, or (2) 2 PORVs, or (3) RCS Depressurized With Vent > 1.58/in.	Same as Mode 4	With Vessel Head on, Same as Mode 4
Support Systems			
PCCW	Two Loops Operable [3.7.3]	None	None
SWS	Two Loops Operable [3.7.4] Ultimate Heat Sink [3.7.5]	None	None
Ventilation	Two Trains of Control Room Ventilation Operable [3.7.6] Area Temp. Monitoring Within Specified Limits [3.7.10]	Same as Mode 4	Same as Mode 4
AC Power	Two Offsite Circuits, Two Diesel Generators, Two Emergency Buses [3.8.1.1, 3.8.3.1]	One Offsite Circuit, One Diesel Generator, One Emergency Bus Operable [3.8.1.2, 3.8.3.2]	Same as Mode 5
DC Power	Two Trains Operable (Two Batteries, Two Battery Chargers, and Two Buses in Each) [3.8.2.1, 3.8.3.1]	One Train Operable (Two Batteries, Two Battery Chargers, and Two Buses) [3.8.2.2, 3.8.3.2]	Same as Mode 5

TABLE C-1: SUMMARY OF SHUTDOWN TECHNICAL SPECIFICATIONS - FOR MODES 4, 5, AND 6

FUNCTION	OPERABILITY REQUIREMENTS		
	MODE 4 (Hot Shutdown)	MODE 5 (Cold Shutdown)	MODE 6 (Refueling)
Instrumentation			
ESFAS	o SI - Manual, Logic & Relays o Spray - Manual, Logic & Relays o Cont. Isolation A, B - Manual, Logic & Relays. COP rad. High o Auto Switchover to Sump - Logic & Relays, RWST lo lo with SI o Loss of Power (Start EFW) [3.3.2]	None	None
RTS	Manual Reactor Trip, Trip Breakers, Source Range Neutron Flux Monitors [3.3.1]	Same as Mode 4	Two Source Range Neutron Flux Monitors [3.9.2]
Rad. Monitoring	RCS Leak Detection, Cont. Vent. On-Line Purge, Main Steam Line, Control Room Air Intakes, PCCW Loops A, B Cont. Post-LOCA Area [3.3.3.1]	Cont. Vent. Crane Area Monitor, Control Room Air Intakes, PCCW Loops A & B, Cont. Post-LOCA Area Monitor [3.3.3.1]	Same As Mode 5
Misc. Monitoring	Seismic, Met., Rad. Liquid Effluent, Rad. Gaseous Effluent [3.3.3.3, 3.3.3.4, 3.3.3.9, 3.3.3.10]	Same as Mode 4	Same as Mode 4

TABLE C-1: SUMMARY OF SHUTDOWN TECHNICAL SPECIFICATIONS - FOR MODES 4, 5, AND 6

FUNCTION	OPERABILITY [QUIREMENTS		
	MODE 4 (Hot Shutdown)	MODE 5 (Cold Shutdown)	MODE 6 (Refueling)
Containment	Cont. Spray System, Spray Addit'.e Tank Operable [3.6.2.1, 3.6.2.2]	None	None
	Cont. Isolation Valves, Cont. Leakage, Cont. Ai Lock Operable [3.6.3, 3.6.1.2, 3.6.1.3]	None	For Core Alterations or Movement o' Irradiated Fuel Cont. Building Penetration - Equipment Hatch Door With Minimum of 4 Bolts - One Door in Each Airlock Closed - Each Penetration From Containment to Environment Either Closed or Auto Isolated [3.9.4]
	Cont. Purge Supply & Exhaust Isolation Valves - 36" Valves Locked Closed, 8" Valves Closed Except for Purge Operation [3.6.1.7]	None	During Core Alterations or Movement of Irradiated Fuel Cont. Purge Supply and Exhaust Isolation System Operable [3.9.9]

APPENDIX D

ANALYSIS OF FIRE FREQUENCY DURING SHUTDOWN

PLG-0602

ANALYSIS OF FIRE FREQUENCY DURING SHUTDOWN

Project Manager

Karl N. Fleming

Principal Investigators

Nathan O. Siu
William A. Bromley
Patrick Y. C. Chen
Mardyros Kazarians
Douglas C. Iden

Prepared for
PUBLIC SERVICE OF NEW HAMPSHIRE
New Hampshire Yankee Division
Seabrook, New Hampshire
March 1988

Pickard, Lowe and Garrick, Inc.
Engineers • Applied Scientists • Management Consultants
Newport Beach, CA Washington, DC

CONTENTS

LIST OF TABLES AND FIGURES

1. INTRODUCTION

The objective of this work is to estimate the frequency of fire occurrences in a nuclear power plant during shutdown. This investigation supports a larger study to determine the risk caused by a wide spectrum of initiating events that could occur during shutdown conditions and will help show if there is a significant change in the fire risk during this period. To obtain estimates of fire frequency during shutdown, it was necessary to analyze data in greater detail than had previously been performed to support estimates of fire frequency during plant operation. A byproduct of this work is a detailed reclassification of all reported fire occurrences and estimates of fire frequency in operation and in shutdown.

This section first outlines the fire frequency model and the study procedure, then presents a summary of the results. Section 2 describes the sources of fire occurrence data and the handling of discrepancies and overlap among them. The process for structuring the fire data base and a description of the data base characteristics are included in Section 3.

The fire frequency analysis and results for specific rooms and buildings are presented in Section 4. There is a supplement to this report that is proprietary to PLG and contains the detailed fire occurrence data base and the exposure time for the plants contributing data in terms of room-years of exposure to fires.

1.1 FIRE FREQUENCY MODEL

To better understand the frequencies estimated in this work, it is necessary to briefly describe the fire frequency model used in the shutdown fire risk study.

The fire occurrence rate for a given room is a function of such characteristics as room occupancy (equipment and operators), traffic, activities performed, fuel loading, and so forth. In the model used in this work, the variability caused by these characteristics is treated using a single parameter: the "location" (Reference 1-1).

Four location classes are of special interest: the control room, the cable spreading room, the auxiliary building, and the turbine building. Note that although the first two classes are subsets of the third class, their risk significance warrants their separate analysis. A previous study of the Seabrook Station has shown these four areas to be the principal contributors to fire risk since they are most likely to contain locations in which a fire may cause an initiating event and may damage mitigating functions (Reference 1-2). Although the turbine building does not contain a large inventory of accident-mitigating equipment, turbine building fires were identified in the Seabrook study as being significant because of a potential for resulting in a nonrecoverable loss of offsite power condition. Although the impact of fires during shutdown is probably bounded by the impact of fires during operation, there is reason to believe that the frequency of fires could be greater in at least some of these critical areas. Hence, the frequencies of all of these critical areas are reevaluated in this study.

The purpose of this work, then, is to estimate the frequency of control room, cable spreading room, auxiliary building, and turbine building fires during shutdown. The approach used begins with a detailed review and classification of the available data for fire occurrences and a partition of the data base into four types:

1. Construction and precommercial operation fires.
2. Fires that could only have occurred during shutdown.
3. Fires that could have occurred during shutdown or during operation.
4. Fires that could only have occurred during operation.

The data base that was developed and used in this study is described in Section 2 of this report; additional details on the classification scheme are given in Section 3.

For location i, the fire frequency during shutdown is obtained using

$$\lambda_i = \lambda_{i,sd/op} + \lambda_{i,sd} \qquad (1.1)$$

where the units of λ_i are fires per shutdown year. The subscripts in Equation (1.1) refer to the period during which the fire may occur; e.g., $\lambda_{i,sd/op}$ is the frequency of fires in location i that can occur during shutdown or operation. The construction fires observed in the data base are used to aid the estimation of both $\lambda_{i,sd/op}$ and $\lambda_{i,sd}$.

Each of the terms in Equation (1.1) is developed by using the available data base in a two-stage Bayes' analysis (Reference 1-3), as described in Section 4. Note that the construction fire data may not be directly additive to the fire data. The number of construction-type activities potentially leading to fire initiation (e.g., welding) is expected to be lower during shutdown than during construction, and the number of fires per unit shutdown time should be lower.

Note also that the fire occurrence rate during operation can be estimated by using a related equation,

$$\lambda_i^* = \lambda_{i,op} + \lambda_{i,sd/op} \qquad (1.2)$$

where the units of λ_i^* are fires per operation year. The λ_i^* are also analyzed in this study.

It is important to emphasize that Equation (1.1) quantifies the rate of occurrence of fires during shutdown. The first component of this rate, $\lambda_{i,sd/op}$, is assumed to be constant during the entire calendar year. The second component, $\lambda_{i,sd}$, is nonzero only during shutdown.

Similarly, Equation (1.2) quantifies the rate of occurrence of fires during operation. Thus, the total annual fire frequency, $\lambda_{i,T}$, is given by

$$\Lambda_{i,T} = \lambda_i^*(1 - \phi_{sd}) + \lambda_i \phi_{sd} \tag{1.3}$$

$$= \lambda_{i,op}(1 - \phi_{sd}) + \lambda_{i,sd/op} + \lambda_{i,sd}\,\phi_{sd} \tag{1.4}$$

where the units of $\Lambda_{i,T}$ are fires per calendar year and where ϕ_{sd} is the fraction of the year the plant is in shutdown (typically assumed to be 0.30). The annualized frequency of fires during shutdown is therefore given by the second term of Equation (1.3),

$$\Lambda_i = (\lambda_{i,sd/op} + \lambda_{i,sd})\phi_{sd} \tag{1.5}$$

where the units of Λ_i are shutdown fires per calendar year. The initiating events analyzed in the shutdown risk study are in the units of Λ_i.

In this analysis, we will develop the shutdown fire frequency, as defined in Equation (1.1), and the operation fire frequency, as defined in Equation (1.2). The procedure used to evaluate each of the terms is outlined in Section 1.2. The results of the analysis are presented in Section 1.3.

1.2 STUDY PROCEDURE

The procedure used to estimate the individual terms in Equation (1.1) consists of three basic steps. The first step consists of updating the fire event data base used in previous studies (References 1-1 and 1-2) to include the most recent events documented and to perform a detailed classification of the event characteristics. An important source of data is the computerized data base recently produced by Sandia National Laboratories (SNL) (Reference 1-4). This data base contains most nuclear power plant fires reported to the U.S. Nuclear Regulatory Commission or to major nuclear plant insurers from 1965 through June 1985; the data are coded in dBASE III format and are packaged with a number of programs intended to simplify searches through the data file. These data provided a good starting point for this analysis.

To support the objectives of this study, it was decided to enhance the SNL data base with respect to a more complete representation of: (1) the fire event characteristics (e.g., the ignition scenarios are not always clearly specified) and (2) all fire events occurring in nuclear power plants. These enhancements required modifications to the SNL data base. These modifications include the addition of various data fields to treat more complete and new descriptions of fire events (see Section 3) and the inclusion of additional events not covered by the SNL data base (see Section 2). A screening of the data base event descriptions resulted in the removal of several events (e.g., onsite trailer fires), which were intentionally included by SNL although they have little bearing on nuclear plant fire risk analysis.

The second step in the analysis is to group the events in the data base according to whether they could have occurred during shutdown, operation, or both and also to categorize them by location (see Section 3). Categorizing is accomplished by direct examination of the narratives associated with each event; the summary statistics for the categorization are obtained by using the built-in functions of dBASE III.

The third step is the quantitative analysis of the data processed in the second step. The processing involves an application of the two-stage Bayes' method for most of the fires in the data base (Reference 1-3). This method requires the grouping of data by plant to preserve the plant-to-plant variability of the fire occurrence frequency in the course of quanti ing uncertainties in this frequency. In one case, however, special techniques must be employed; that is, the power plant at which the fire occurred is not always specified, which is required in the two-stage Bayes' methodology. The method used to deal with this problem is discussed in Section 4.

1.3 SUMMARY OF RESULTS

The results of this study indicate that the frequency of auxiliary building fires during shutdown is observably higher than the frequency of fires in these locations during power operation. This increase results from the number of fires in the data base that are relevant only to the shutdown period; this, in turn, is because of the potential increase during shutdown in such activities as maintenance. welding, etc., that may lead to fires. The frequency of control room and cable spreading room fires during shutdown may be higher, but the rather weak statistical evidence precludes strong confidence in this conclusion. The frequency of turbine building fi es during shutdown appears to be much the same as that for operation.

Figure 1-1 summarizes the shutdown fire frequency distributions for each of the four locations considered in this study: the control room, the cable spreading room, the auxiliary building, and the turbine building. Figure 1-2 shows the same distributions for operation. For comparison, the distributions computed in Reference 1-1 and used in Reference 1-2 for fires during operation are also presented. For the control room and the auxiliary and turbine buildings, Reference 1-1 distributions are lower; the difference is due primarily to the difference between λ_i and λ_i^*. For the cable spreading room, Reference 1-1 distribution is higher. As discussed in Section 4, the different results in this study are caused by the increased amount of data, the reclassification of some events, and an improved estimation model. In each of these respects, the current results are better supported and should be used in lieu of the Reference 1-1 results.

It should be noted that the results of this study are based only on reported fires. The discussion in Section 4 shows that there is a possibility that the number of reported fires is significantly lower than the number f fires that have actually occurred. While it may be argued that the unreported fires tend to be small and therefore of less importance with respect to plant risk, ignoring their impact detracts from the completeness of this analysis. However, no previous fire risk studies have treated the unreported fires explicitly, and it is judged that a reasonable treatment of such fires is beyond the scope of this study. Further, the assumed lognormal shape of the population variability curves for the fire frequencies and the broad (and fairly flat) prior distributions for the lognormal parameters μ and σ lead to very broad prior distributions for the λ's and may implicitly account for such fires. In the opinion of the authors, the fire frequencies reported here are judged to be reasonable in the context of fire risk assessment. Any extensions of this work may want to consider this problem in detail.

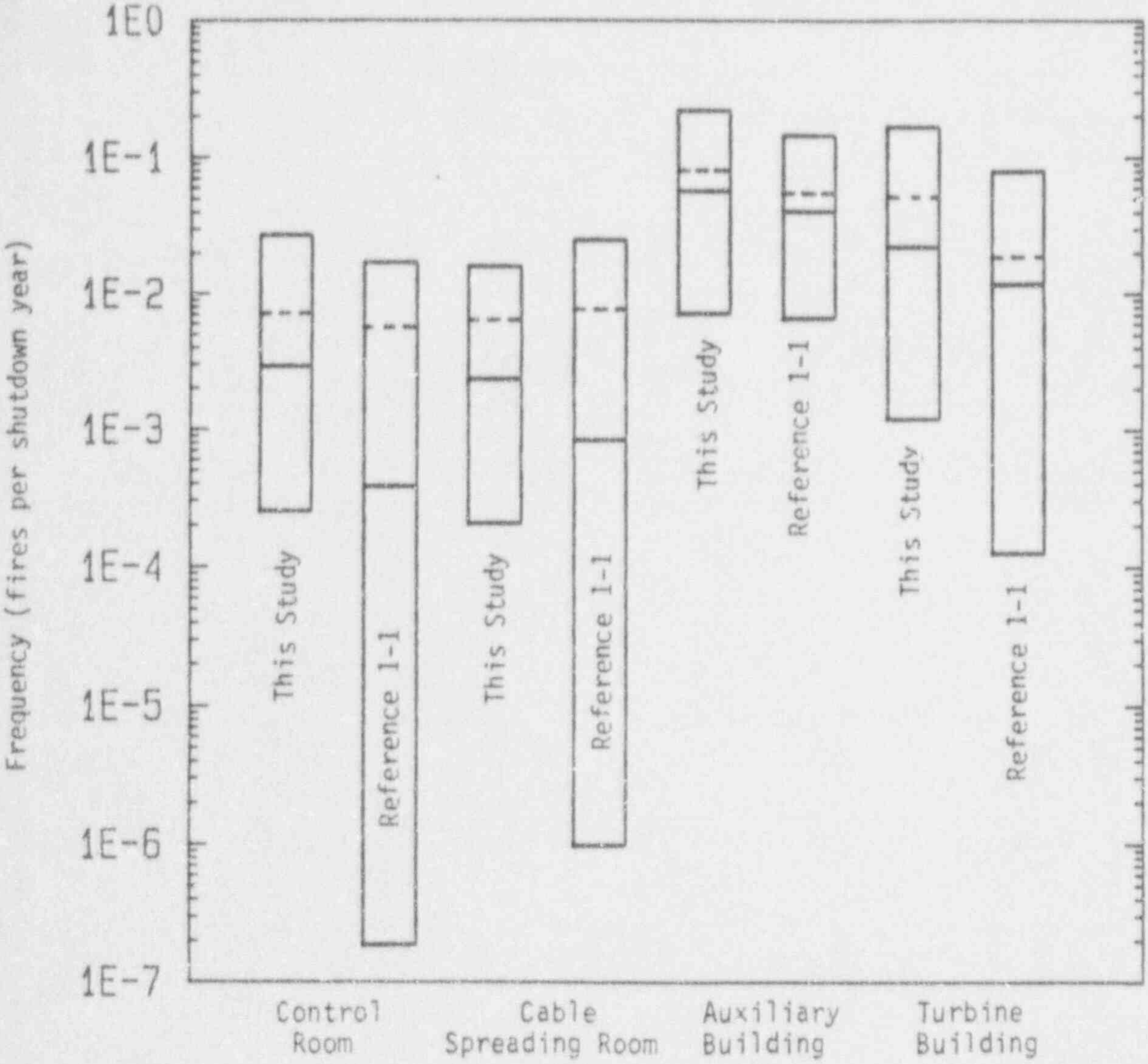
1.4 REFERENCES

1-1. Kazarians, M., and G. Apostolakis, "Modeling Rare Events: The Frequencies of Fire in Nuclear Power Plants," Proceedings of Workshop on Low Probability/High Consequence Risk Analysis, Society for Risk Analysis, Arlington, Virginia, 1983.

1-2. Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment," prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983.

1-3. Kaplan, S., "On a 'Two Stage' Bayesian Procedure for Determining Failure Rates from Experiential Data," Institute of Electrical and Electronics Engineers Transactions on Power Apparatus and Systems, Vol. PAS-102, No. 1, January 1983.

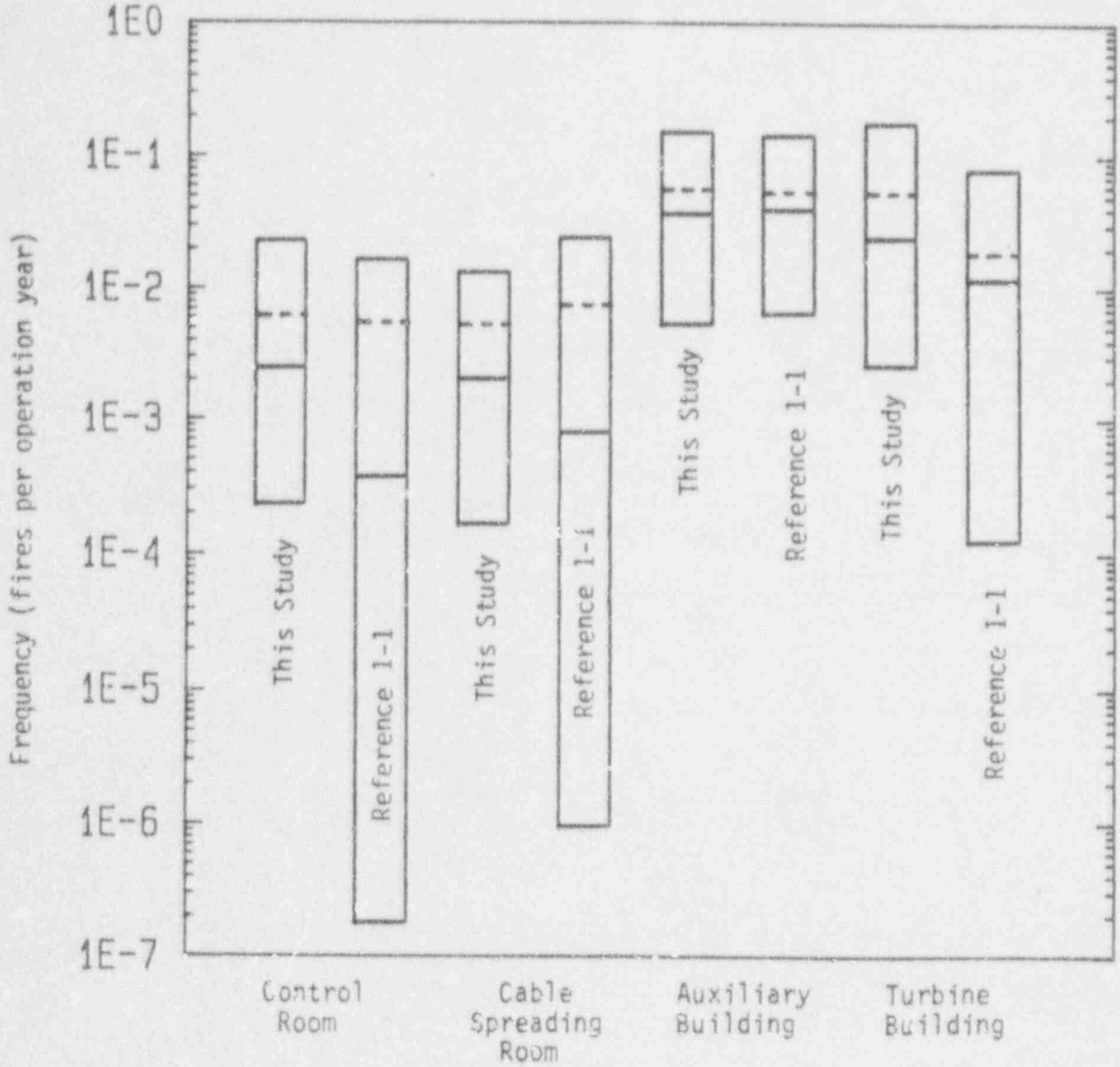
1-4. Wheelis, W. T., "User's Guide for a Personal-Computer-Based Nuclear Power Plant Fire Data Base," Sandia National Laboratories, NUREG/CR-4586, SAND86-0300, August 1986.



NOTE: Results of Reference 1-1 are in terms of fires per operating year.

Legend:
- 95th Percentile
- Mean
- 50th Percentile
- 5th Percentile

FIGURE 1-1. LOCATION-DEPENDENT SHUTDOWN FIRE FREQUENCIES (FIRES PER SHUTDOWN YEAR)



NOTE: Results of Reference 1-1 are in terms of fires per operating year.

Legend
95th Percentile
Mean
50th Percentile
5th Percentile

FIGURE 1-2. LOCATION-DEPENDENT OPERATION FIRE FREQUENCIES (FIRES PER OPERATION YEAR)

2. FIRE OCCURRENCE DATA SOURCES

The fire frequency distributions used in the Seabrook Station Probabilistic Safety Assessment (SSPSA) (Reference 2-1) are based on an earlier analysis performed in Reference 2-2. Reference 2-2 uses fire occurrence data for operating nuclear power plants collected up through 1981. The primary reference source is Nuclear Power Experience (NPE) (Reference 2-3), which, in turn, is based largely on Licensee Event Reports (LER).

In this study, the data base of Reference 2-2 is extended to include fires reported up to July 1987 and to include fires reported in sources other than NPE. Three sources are used to develop the new data base: the Sandia National Laboratories (SNL) data base (Reference 2-4), NPE (Reference 2-3), and a report prepared for the Electric Power Research Institute (EPRI) (Reference 2-5). Each of these sources is described in this section.

2.1 SNL DATA BASE

The primary reference source for this work is a computerized data base compiled by SNL for the U.S. Nuclear Regulatory Commission (Reference 2-4). This data base, which is encoded in dBASE III data files, contains information for 354 occurrences between 1965 and June 1987. The data included were obtained from a number of sources, including NPE, LERs, and American Nuclear Insurers.

Each event in the SNL data base is characterized by 31 data entries ("fields"). These entries indicate the general characteristics of the plant involved (e.g., the reactor type) as well as the specific parameters associated with the fire; e.g., its duration.

Because the SNL data base is computerized, searches of the data base can be performed rather easily. Reference 2-4 provides a number of programs to aid in the searching process, but the use of these programs is not necessary for effective use of the data base.

Although the SNL data base represented an excellent starting point, three limitations were identified with respect to the objectives of this study: (1) a significant number of events included are irrelevant to nuclear power plant fire risk, (2) a small number of events reported in other sources are not included, and (3) the 31 fields do not cover all event information needed for this analysis. The first item is addressed by a screening of the overall data base, as described in Section 3. To increase the completeness of the data base and address the second concern, References 2-3 and 2-5 have been thoroughly reviewed and cross-correlated with Reference 2-4. From this review and cross-correlation of data, 51 events not included in the SNL data base have been added to the data base for this study. Some of these events occurred at foreign plants and are screened out prior to quantification. To address the third concern, the SNL data base is modified by adding 13 data fields, as discussed in Section 3.

2.2 OTHER DATA BASES

As discussed above, References 2-3 and 2-5 have been reviewed to improve the completeness of the data base.

NPE is a periodic compilation of reportable events occurring at nuclear power plants. NPE data are based primarily on Licensee Event Reports. The purpose of NPE is to provide a vehicle for sharing industry experience among all interested parties.

For the period 1968 through July 1987, a total of 138 fire events was found in NPE. Due to variations in interpreting reporting requirements among nuclear plant operators, the event reports vary in content. They often (but do not always) describe the ignition cause, the medium of propagation, the method of suppression, the components affected, and the plant and operator reactions to the event. Some reports may only be a few lines long, while others (notably, the report on the Browns Ferry cable spreading room fire of 1975) may cover several pages.

The EPRI report (Reference 2-5) presents an analysis of 116 fire occurrences between 1965 and February 1982. Fifty-nine of these fi - occurred at operating nuclear plants in the United States between January 1978 and February 1982; some of these fires are also reported in NPE (note that NPE is not restricted to fires in operating plants), while the records of others are obtained from the files of American Nuclear Insurers.

The event reports given in Reference 2-5 can be broken into two groups: those for fires before December 1977 and those for fires occurring after this date. The reports for the first group are more complete than those for the second; both groups, however, omit the name of the plant involved, which increases the difficulty of using this information in a two-stage Bayes' analysis (see Section 4).

Because the records for a number of fires reported in Reference 2-5 are private, some of the fires included in that reference are not included in Reference 2-3. For example, Reference 2-5 reports 10 turbine building fires before May 1978, while Reference 2-3 reports 8 turbine building fires up to December 1981. In general, discrepancies between the two sources are not very large; it is believed that those events reported in Reference 2-5 but not in NPE are relevant because they provide an indication of the total fire occurrence rate within the nuclear plant, regardless of the safety implications.

2.3 COMMON EVENTS

Because the three data sources used ove , it is necessary to identify those events appearing in more than one data source. This is accomplished primarily by identifying those events sharing common occurrence dates and reviewing their descriptions. For the control room, cable spreading room, auxiliary building, and turbine building, 45 events are reported in more than one source.

Because of the lack of information by some of the event reports, it is not clear if the 45 events identified include all of the duplicate events in the data base. Because it is believed that the number of unidentified duplicate events is relatively small, and because any error due to missing such events is conservative, further investigation of the data base is not deemed necessary.

2.4 REFERENCES

2-1. Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment," prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983.

2-2. Kazarians, M., and G. Apostolakis, "Modeling Rare Events: The Frequencies of Fire in Nuclear Power Plants," Proceedings of Workshop on Low Probability/High Consequence Risk Analysis, Society for Risk Analysis, Arlington, Virginia, 1983.

2-3. S. M. Stoller Corporation, Nuclear Power Experience, 1986.

2-4. Wheelis, W. T., "User's Guide for a Personal-Computer-Based Nuclear Power Plant Fire Data Base," Sandia National Laboratories, NUREG/CR-4586, SAND86-0300, August 1986.

2-5. Dungan, K. W., and M. S. Lorenz, "Nuclear Power Plant Fire Loss Data," prepared for the Electric Power Research Institute by Professional Loss Control, Inc., EPRI-NP-3179, 1983.

3. FIRE DATA BASE

The fire data base used in this study is developed by consolidating and updating the data sources described in Section 2. A total of 406 events is included for the period 1965 to July 1987. Of these, 256 are relevant to this study and will be further analyzed.

3.1 DATA BASE STRUCTURE

The fire data base is contained in dBASE III files. The structure of these files is a reorganized and modified version of that used by the SNL data base (Reference 3-1). This modification consists of adding 13 data entry fields to the original 31 fields (each field contains data characterizing the fire event). The fields for the new data base are listed and described in Table 3-1. An example of a typical entry in the fire data base is shown in Figure 3-1.

The purpose of adding fields is to allow characterization of the data base in terms of parameters not considered by Reference 3-1. For example, Reference 3-2 describes an approach for analyzing the frequency of nuclear power plant fires that requires detailed information concerning the causes of the fire. Some of the informational needs are: the mechanisms by which fuel and an ignition source are introduced into the area and the size of the initiating fire. Other fields added characterize the safety equipment/systems affected by the fire, whether fire barriers were present and breached and whether other significant conditions (e.g., heavy smoke or water damage) should be flagged.

3.2 DATA BASE CHARACTERISTICS

The data base used in this study is obtained by screening the raw data base (406 events) to remove such inappropriate events as grass, warehouse fires, trailer fires, and those fires that occurred in temporary buildings. The remaining 256 events are categorized according to: (1) their possibility of occurring during a given plant operational mode at the time of the fire event and (2) the location of the event. The four operational mode categories of interest are:

1. Construction. This includes applicable events categorized as occurring during the construction and preoperational testing modes of Reference 3-1.

2. Shutdown Only. This includes events from the maintenance outage, refueling outage, and cold shutdown modes from the modified Reference 3-1 data base that were judged to only have a high likelihood of occurrence during cold shutdown conditions. For example, if the conditions that caused the ignition source and fuel to come together could only occur during shutdown conditions, such as those due to prolonged operation of shutdown cooling pumps, then the selected event was put into this category.

3. Operating or Shutdown. This category contains events selected on the basis that they either occurred during shutdown conditions (as

defined above) but could have occurred during operation or that they occurred during operation but could have just as easily occurred during shutdown conditions.

4. Operating Only. This includes the remainder of the events in the modified data base. These events are categorized by conditions unique to hot operating modes; i.e., hot shutdown or power operation. For example, if the ignition source was a pipe that would only be hot during operating conditions, then the event would fall into this category.

As discussed earlier, four location categories are of interest in this study: the auxiliary building, the turbine building, the control room, and the cable spreading room.

There are good reasons to believe that fires in the four location categories include those that dominate the shutdown fire risk. They include all the locations systematically identified in the SSPSA (Reference 3-3) for power operation events. The impact of fires in these locations should bound the impact of shutdown fires. The categories are similar to, but not identical with, the location groupings presented in Table 6 of Reference 3-1. The number of fires for each mode and location is plotted in Figure 3-2.

3.2.1 AUXILIARY BUILDING

The location class "auxiliary building" includes both the control and auxiliary buildings of current plants; of course, the actual contents (and even names) of these buildings can vary from plant to plant. In the case of Seabrook Station, the generic term of auxiliary building includes the RHR equipment vault. For purposes of this evaluation, fires occurring in the following locations (as determined from the SNL data base) are assumed to occur in the control building portion of the auxiliary building class:

- Battery Room
- Cable Riser Area
- Computer Room
- Control Building
- Switchgear Room

This grouping is a natural one from the fire occurrence standpoint since it can be seen that the contents of these different rooms are similar (they do not house large mechanical equipment, for example).

It can also be argued that cable spreading rooms and control rooms are located within the control building and thus should be included in the broad auxiliary building class definition. However, the significance of fires in these special areas is substantial enough to warrant an independent frequency quantification for each; they are discussed in later sections.

Auxiliary buildings for nuclear power plants typically house components of such primary auxiliaries as the residual heat removal (RHR) safety injection, and chemical and volume control systems, as well as components of the radwaste processing systems and ventilation systems; e.g., charcoal filters. The fire locations (as defined in the SNL data base and used in the modified data base) containing equipment that corresponds to that described above include:

- Auxiliary Building
- Pump Room
- Radwaste Building
- Reactor Annulus
- Recombiner Building
- Reactor Building (for boiling water reactors)

Together with the rooms listed earlier, these compose the auxiliary building location class. Note that the diesel generator building, the intake structure, and electrical tunnel locations are not considered as part of the auxiliary building.

The results of the data search are tabulated in Table 3-2. The four columns correlate to the operational mode categories described earlier.

Table 3-2 shows that a number of auxiliary building fires are categorized as being relevant only during operation. Most of these are fires that occur in the recombiner building. The SSPSA (Reference 3-3), using an exhaustive, systematic analysis, has shown that off-gas, system-related fires have little effect on plant risk at Seabrook and need not be included in the risk study. Such fires are therefore screened out of the data base used in the study prior to quantification.

Table 3-2 also shows that a number of fires could have occurred only during shutdown. It should be noted, however, that six of the shutdown only events are small welding fires that occurred at a single plant over the span of a few months. These events are probably not independent since they appear to be the result of a single breakdown in administrative procedures; the shutdown fire frequency is therefore not as strongly affected as implied by the table. This group of events will be further discussed in Section 4.

3.2.2 TURBINE BUILDING

The applicable turbine building fires included in the data base are categorized in Table 3-3.

The location class "turbine building" includes both the turbine building and boiler room locations of the SNL data base. This grouping was chosen because of the similarity of equipment and fuels found in these locations, it being hypothesized that the secondary plant housed within the turbine building is analogous to a larger version of a boiler room with a turbine generator added. It is interesting to note that no applicable events were categorized in the boiler room location. This is probably due to the fact that few plants have auxiliary nonnuclear boilers.

3.2.3 CONTROL ROOM

The four control room fires included in the data base were all categorized as operation or shutdown, as shown in Figure 3-2. All four fires were very small (three might actually be better termed as fire precursors) and were easily extinguished. However, it is judged that all four fires were capable of spreading (although slowly), and are therefore relevant. All four fires are included in the control room fire frequency analysis; reductions to the fire frequency on the basis of fire severity are performed in a later step of a fire risk analysis, as described in References 3-3 and 3-4.

Note that the date base does not contain any control room fires judged to be possible only during shutdown conditions. This is not surprising, given the rarity of any type of control room fire. It is believed that the lack of data should not be used to infer that this class of fires is not possible; i.e., to omit $\lambda_{CR,sd}$ in Equation (1.1). The lack of data only provides evidence that the value of $\lambda_{CR,sd}$ is likely to be small.

3.2.4 CABLE SPREADING ROOM

The three cable spreading room fires included in the data base were categorized as one construction and two operation or shutdown, as shown in Figure 3-2. The most severe event is the well-known Browns Ferry fire of March 1975. The other event linked to a plant occurred at Peach Bottom 3; this fire was small and was caused by the use of flammable plastic in relays.

As in the case of the control room, no fires that could have occurred only during shutdown have been observed. We therefore expect $\lambda_{CSR,sd}$ to be small, but not necessarily zero.

3.3 REFERENCES

3-1. Whe lis, W. T., "User's Guide for a Personal-Computer-Based Nuclear Power Plant Fire Data Base," Sandia National Laboratories, NUREG/CR-4586, SAND86-0300, August 1986.

3-2. Siu, N., M. Kazaraians, and G. Apostolakis, "Modeling Fire Initiation in Nuclear Power Plants," Transactions of the Ninth International Conference on Structural Mechanics in Reactor Technology, Lausanne, Switzerland, August 17-21, 1987.

3-3. Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment," prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983.

3-4. Kazarians, M., N. Siu, and G. Apostolakis, "Fire Risk Analysis for Nuclear Power Plants: Methodological Developments and Applications," Risk Analysis, Vol. 5, No. 1, 1985.

TABLE 3-1. FIRE DATA BASE FIELD DESCRIPTIONS

Sheet 1 of 9

File Field	Description
1	Incident Number. This number is assigned to each fire incident. Numbers range from 1 to 354 chronologically and from 355 to 404 in random temporal sequence. This number, called an INO, also corresponds to the same number in the description data base.
2	State, Town. The state (or country) in which the plant is located and the closest town or city.
3	Plant and Unit. The plant name and unit number where the fire occurred.
4	Utility. The principal utility (or group) that operates the plant.
5	Reactor Type. The type of reactor at the plant of interest. Entries for this data element are: BWR (boiling water reactor) PWR (pressurized water reactor) HTGR (high-temperature gas reactor)
6	Reactor Supplier. The nuclear reactor supplier. Entries for this data element are: Westinghouse, Combustion Engineering, Babcock & Wilcox, Kraftwerk Union AG, General Atomic, General Electric, Allis-Chalmers, ASEA-Atom
7	Capacity. The reactor output, expressed in net megawatts (electric). (For example, 1,000 MWe.)
8	Date of Operating License. The date of issue of a reactor operating license.
9	Data of Initial Criticality. The date the nuclear reactor first went critical (a self-sustaining nuclear reaction occurred in the reactor).
10	Date of Commercial Operation. The date the reactor was formally connected to a commercial power grid.

TABLE 3-1 (continued)

Sheet 2 of 9

File Field	Description
11	Date of Fire. The date of the fire is listed in this field.
12	Time. The time (in military standard time) the fire occurred.
13	Location. The location, inside or outside the plant, where the fire occurred. Entries for this data element are: Administration Building Auxiliary Building Battery Room Boiler Room Cable Riser Area Cable Spreading Room Change House Computer Room Containment Control Building Control Room Cooling Tower Diesel Generator Building Drywell Fire Pump House Maintenance Shop Manhole Offsite Other Building Pump Room Radwaste Building Reactor Annulus Reactor Building Recombiner Building Security Building Service Building Stack Filter House Switchgear Room Temporary Building TIP Room Transformer Yard Turbine Building Warehouse Yard
14	Size. Approximate qualitative size of fire. Entries for this data element are: Precursor (examples: burned relay contact and shorted terminal; fire never propagates) Small (examples: wastebasket and burned relay; capable of being extinguished by one person without assistance) Medium (examples: electrical panel fires and oil fires due to accumulated leakage; extinguished by fire brigade with several hand-held extinguishers) Large (examples: explosions affecting more than one room or component; extinguished with multiple hoses with offsite assistance)
15	Duration. The duration (hours:minutes) of the fire.

TABLE 3-1 (continued)

Sheet 3 of 9

File Field	Description
16	Duration Flag. This is a number that corresponds to the time that a fire burned. The values range from 0 to 6 and mean the following: 0 - Fire Precursor 1 - < 1 minute 2 - ≥ 1 minute but < 5 minutes 3 - ≥ 5 minutes but < 15 minutes 4 - ≥ 15 minutes but < 30 minutes 5 - ≥ 30 minutes but < 1 hour 6 - ≥ 1 hour
17	Mode of Operation. The plant status at the time of the fire. Entries for this data element are: Construction Preoperational Testing Power Operation Hot Shutdown Cold Shutdown Refueling Outage Maintenance Outage
18	Cause of Fire. The cause of the fire. Entries for this data element are: Component Failure Electrical Failure Welding and Cutting Design/Fabrication Error Defective Procedure Arson Personnel Error Spontaneous Combustion Explosion Overheated Material Suspicious Origin Lightning

TABLE 3-1 (continued)

Sheet 4 of 9

File Field	Description
19	Type of Fire. The type of fire that occurred in reference to National Environment Policy Act/National Fire Protection Association Standards is listed here: Class A (ordinary combustibles, such as wood or paper) Class B (flammable liquids and gases) Class C (electrical fires) Class D (combustible metals)
20	Ignition Cause. Description of the source of ignition. Entries for this data element are: Electrical Arcing Hot Surfaces Friction Heating Grinding/Welding Sparks Auto Ignition
21	Ignition Category. Categorization of availability of ignition source. Entries for this data element are: In Situ Transient
22	Conditional Ignition Category. Categorization of ignition source conditioned on the response to Ignition Category. Conditional entries for this data element are: In Situ: Normally Present (examples: hot surfaces, potential electrical arcs) Component Failure (examples: electrical or mechanical failure) Transient: Used in Room (examples: maintenance items, construction/repair materials) Administrative Violation (examples: cigarettes, open flames)

TABLE 3-1 (continued)

Sheet 5 of 9

File Field	Description
23	Extinguished By. The persons, systems, or methods used to extinguish the fire. Entries for this data element are: Automatic System Security Guard Plant Personnel Plant Fire Brigade Offsite Fire Department Construction Workers Self Extinguishing Deenergized Remove Fuel Source
24	Detection Means. The method by which the fire was initially detected: Control Room Observation Construction Workers Fire Watch Heat Detectors Plant Personnel Security Guards Smoke Detectors
25	Detection Time. The time (hours:minutes) of detection relative to the ignition time.
26	Suppression Time. The time (hours:minutes) taken to extinguish the fire once suppression personnel or equipment arrived.
27	Suppression Flag. This is a number that corresponds to the time it took to suppress a fire. The values range from 0 to 6 and mean the following: 0 - Fire Precursor 1 - < 1 minute 2 - $\geq$ 1 minute but < 5 minutes 3 - $\geq$ 5 minutes but < 15 minutes 4 - $\geq$ 15 minutes but < 30 minutes 5 - $\geq$ 30 minutes but < 1 hour 6 - $\geq$ 1 hour
28	Agents Used. The extinguishing agents used to suppress the fire: Dry Chemical Foam Gas-Ansul Gas-CO_2 Gas-Halon Gas-Unspecified Water None

TABLE 3-1 (continued)

Sheet 6 of 9

File Field	Description
29	Equipment Used. The equipment used to extinguish the fire: Automatic Gas System Automatic Deluge System Inside Hose Streams None Outside Hose Streams Portable Extinguishers
30	Initiating Component. The equipment or item that initiated the fire: Air Conditioner Battery Boiler Bus Cable Capacitor Circuit Breaker Circuit Switcher Computer Construction Equipment Degreaser Diode Engine Extension Cord Fan Filter Flood Light Fuse Generator Glove Box Hanger Heat Exchanger Hose Hydrogen Analyzer Hydrogen Recombiner Incinerator Instrumentation Motor Motor Control Center Oxygen Recombiner Pipe Pump Reactor Reheater Relay Resistor Steam Generator Tank Temporary Structure Torch Transformer Turbocharger Turbine Valve Voltage Regulator
31	Initiating Combustibles. The substance that initiated the fire: Carbon Buildup Charcoal Construction Materials Gasoline Hydrogen Insulation Oil Propane Sealant Solvent Waste

TABLE 3-1 (continued)

Sheet 7 of 9

File Field	Description
32	Combustible Category. Categorization of fuel source. Entries to this data element are: In Situ Transient
33	Conditional Fuel Category. Categorization of fuel source conditioned on the response to Combustible Category. Conditional entries for this data element are: In Situ Anticipated (examples: fuel, oil, lube oil, and cable insulation) Unanticipated (examples: improper materials or installation) Transient Used in Room (examples: maintenance items, construction/repair materials) Stored in Room (examples: administrative violation, planned outage)
34	Components Affected. The equipment items affected by the fire are all items listed under "Initiating Components" plus the following: Building Construction Materials Ductwork Electrical Equipment Hanger None Reactor Internals Rupture Disk Seals Substation Trailer Vessel
35	Safety Systems Affected. List of the affected safety systems.
36	Redundant Systems Affected. List of the redundant safety systems and components affected by the fire.

TABLE 3-1 (continued)

Sheet 8 of 9

File Field	Description
37	System/Components Failed. List of the components failed by the fire. Include manufacturer's part number or name plate data if available.
38	Fire Barrier Data. Indicate whether fire barriers were installed (Yes/None) in the location of the fire. When fire barriers were present, state whether they performed as designed.
39	Fire Accessibility. Indicate whether the fire location impeded access (Yes/None) to fire fighters and equipment.
40	Significant Conditions. Description of significant conditions produced by or exhibited by the fire. Entries for this data element are: Smoke — Toxic Gases Smoldering Fire — Poor Ventilation
41	Power Degradation. The percentage power degradation of the reactor unit (represented as x%) that resulted from the fire. If the unit was shut down because of the fire, it is represented by the designation "Scram".
42	Forced Outage. The number of days of outage (represented as x days) caused by the fire.
43	Direct Loss. The dollar value loss incurred because of the fire. Entries are represented as follows: < $5k (less than $5,000 damage) $5k to $50k (between $5,000 and $50,000 damage) $50k to $100k (between $50,000 and $100,000 damage) $100k to $500k (between $100,000 and $500,000 damage) $500k to $1M (between $500,000 and $1,000,000 damage) > $1M (greater than $1,000,000 damage) $100M (approximately $100,000,000 damage)

TABLE 3-1 (continued)

Sheet 9 of 9

File Field	Description
44	Reference. The source material in which the fire incident was documented. When available, include the specific citation for the following sources: LPRA (Limerick PRA) LER (Licensee Event Report) NPE (Nuclear Power Experience) ANI (American Nuclear Insurers) EPRI (Electric Power Research Institute-NP-3179) PRE (Power Reactor Events - NUREG/CR-0051) MEMO (Memo from W. J. Dircks to Commissioner Bradford) MK (PLG fire occurrence data)

TABLE 3-2. BREAKDOWN OF AUXILIARY BUILDING FIRES

Location	Construction	Shutdown Only	Operation or Shutdown	Operation Only
Battery Room	0	0	4	0
Cable Riser Area	1	1	0	0
Computer Room	1	0	0	0
Control Building	2	0	2	0
Switchgear Room	2	6	12	0
Auxiliary Building	2	1	18	3
Pump Room	0	0	2	0
Radwaste Building	0	0	0	2
Reactor Annulus	0	0	0	0
Recombiner Building	0	0	1	9
Total	8	8	39	14

1670P32688:10

TABLE 3-3. BREAKDOWN OF TURBINE BUILDING FIRES

Location	Construction	Shutdown Only	Operation or Shutdown	Operation Only
Boiler Room	0	0	0	0
Turbine Building	8	4	10	14
Total	8	4	10	14

PLANT NAME : Browns Ferry 1 CAPACITY : 1065 MWe INO : 100

PRINCIPAL OWNER UTILITY : Tennessee Valley Authority
PLANT LOCATION : AL, Decatur
NSSS VENDOR : General Electric REACTOR TYPE : BWR
OPERATING LICENSE ISSUED : 12/20/73
INITIAL CRITICALITY : 08/17/73 DATE OF COMMERCIAL OPERATION : 08/01/74

FIRE LOCATION : Cable Spreading Room DATE OF FIRE :03/22/75
TIME OF DAY OF FIRE : FIRE DURATION : 07:30
MODE OF PLANT OPERATION : Power Operation
PROBABLE CAUSE OF FIRE : Defective Procedure
TYPE OF FIRE : Class A
DETECTED BY : Plant Personnel
EXTINGUISHED BY : Plant Personnel, Offsite Fire Department
SUPPRESSION EQUIPMENT : Inside Hose Streams, Portable Extinguisher
SUPPRESSION AGENT(S) : Water
SUPPRESSION TIME : 07:00
INITIATING COMPONENT : Torch
INITIATING COMBUSTIBLE : Sealant
COMPONENTS AFFECTED BY FIRE : Cable
POWER DEGRADATION (%) : SCRAM FORCED OUTAGE : 350 Days $LOSS : $100M

REFERENCES : EPRI, NPE, LER

Event Description :

A fire occurred in Units 1 and 2 cable spreading room. Containment penetration sealant was ignited by a candle flame being used to check the penetration for leakage. Because of the pressure differential kept between the CSR and the RB, the fire quickly spread to the RB.

FIGURE 3-1. TYPICAL ENTRY IN FIRE DATA BASE

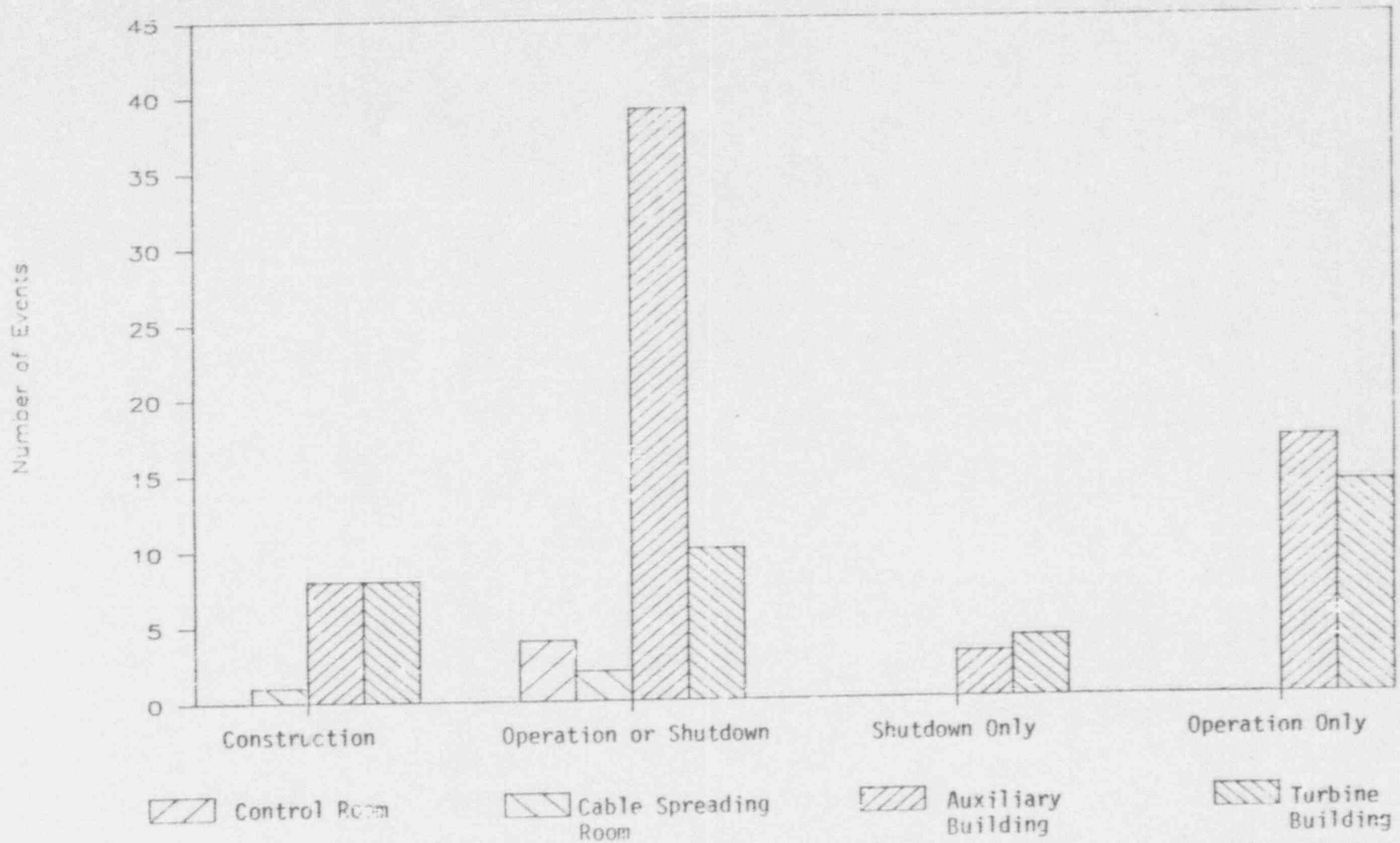


FIGURE 3-2. DISTRIBUTION OF SCREENED FIRE EVENT DATA BY OPERATIONAL MODE AND LOCATION

4. FIRE FREQUENCY ANALYSIS

The frequency of fires during shutdown for a given location in a plant is quantified as described in Section 1:

$$\lambda = \lambda_{sd} + \lambda_{sd/op} \tag{4.1}$$

where

λ_{sd} = frequency of fires that can occur only during shutdown.

$\lambda_{sd/op}$ = frequency of fires that can occur during shutdown or operation.

and λ is in units of fires per shutdown year.

The shutdown term includes construction-type fires not expected to occur during a normal shutdown, but that may occur during an extended outage when large-scale plant modifications may be made. The shutdown/operation term includes fires that occurred during construction (or preoperational testing) that could have occurred during normal plant shutdown or operation.

As discussed in Section 1, Equation (4.1) gives the rate of fire occurrence during shutdown; i.e. the number of fire events per unit time. To annualize this rate, we multiply by the fraction of time the plant is in shutdown conditions, ϕ_{sd}:

$$\Lambda = (\lambda_{sd/op} + \lambda_{sd})\phi_{sd} \tag{4.2}$$

where Λ is in units of fires per calendar year.

Unless stated otherwise, the frequencies discussed below in this section are the unmodified quantities; i.e., those used in Equation (4.1).

A similar approach is used to estimate the fire frequency during operation.

$$\lambda^* = \lambda_{sd/op} + \lambda_{op} \tag{4.3}$$

where

λ_{op} = frequency of fires that can only occur during operation.

The units of λ^* are in fires per operation year.

4.1 GENERAL ESTIMATION PROCEDURES

The estimation procedure used in this study is based on the two-stage Bayesian analysis methodology (Reference 4-1). It is assumed that the total frequency of fires for a given location varies from site-to-site (and not unit-to-unit, as is assumed in most applications of the methodology). This assumption is due to the belief that much of the difference in fire occurrence rates can be attributed to differences in management, which, for multiunit sites operated by a single utility, should not be too great.

The random variation in the location-dependent fire frequency is assumed to be governed by a lognormal distribution whose parameters, μ_i and σ_i (the i denotes the ith location), are unknown. The purpose of the estimation process is to develop the probability distribution for μ_i and σ_i, given the evidence from the data base ($r_{i,k}$ fires in $T_{i,k}$ years for location i, site k). This distribution is hen used to average the lognormal distribution for λ.

The RISKMAN®4 code is used to perform the actual computations; the following section describes a change in methodology required to address a problem with the current data base.

4.2 METHODOLOGY MODIFICATION

One problem with the available data prevents the analyses for $\lambda_{sd/op}$ and λ_{sd} from being entirely straightforward. The two-stage Bayes' methodology requires knowledge of the particular site at which the fire occurred; however, event descriptions obtained from insurance sources generally omit the name of the plant. Thus, it is known that a fire occurred, but it is not known where that fire occurred.

The formal treatment of the uncertainty in attributing an event to a given plant is not difficult in principle. Consider a single unattributed fire event, and assume that there are K plant sites at which the fire could have occurred. Define hypothesis k as follows:

H_k: the fire occurred at site k ($1 \le k \le K$)

Clearly, only one of the K hypotheses is true; the probability that H_k is true is denoted by $P(H_k)$. Using this notation, the posterior distribution for (μ_i, σ_i) is given by

$$\pi_1(\mu_i, \sigma_i | E) = \sum_{k=1}^{K} \pi_1(\mu_i, \sigma_i | H_k) \, P(H_k) \tag{4.4}$$

where $\pi_1(\mu_i, \sigma_i | H_k)$ is the location-dependent posterior distribution obtained from the two-stage Bayes' approach, assuming that the fire occurred at site k. If the hypotheses are equally likely (i.e., we have no reason to choose one site over another),

$$\pi_1(\mu_i, \sigma_i | E) = \frac{1}{K} \sum_{k=1}^{K} \pi_1(\mu_i, \sigma_i | H_k) \tag{4.5}$$

A practical problem with this approach is that the number of hypotheses, and therefore the number of RISKMAN4 runs, increases geometrically with the number of unattributed events. For example, if there are just two such events, K^2 joint hypothesis $H_{jk} = \{H_j, H_k\}$ $(1 \le j \le K, 1 \le k \le K)$ must be considered. To limit the cost of this study, an empirical solution that retains some of the character of the formal solution was used.

In this approach, only two assignments of the unattributed events (hypotheses) are allowed; the first is conservative, while the second is optimistic. The assignment procedure is based on a two-step ranking of the sites. In the first step, the sites are ranked by the total number of fires experienced; the "worst" sites have the highest number of fires and the "best" have the least number of fires (0 in this case). Within each group of sites defined by this first ranking, the sites are further ranked by the number of operating years; the "worst" site has been operating the shortest time, and the "best" has been operating the longest time. In this context, "best" and "worst" refer only to the potential impact on estimated fire frequency of assigning an unattributed fire to the site.

Using this ranking, if there are N unattributed fires, the conservative hypothesis, H_c, is that these fires occurred at the "worst" N plants. The only two restrictions are: (1) no plant is assigned more than one unattributed fire (such an assignment is less likely, assuming independent events and identical assignment probabilities); and (2) an event is not assigned to a plant where the fire could not have occurred; e.g., if the fire occurred at a boiling water reactor, and the worst plant is a pressurized water reactor.

The optimistic hypothesis, H_o, is that the unattributed fires occurred at the "best" N plants. Assignments of unspecified events are made analogously to the conservative case.

The posterior distribution for (μ_i, σ_i) is then obtained using

$$\pi_1(\mu_i, \sigma_i | E) = \frac{1}{2} [\pi_1(\mu_i, \sigma_i | H_c) + \pi_1(\mu_i, \sigma_i | H_o)] \qquad (4.6)$$

where $P\{H_c\} = P\{H_o\} = 1/2$ since only these two hypotheses are allowed in this procedure and since we believe these hypotheses to be equally likely.

4.3 UNREPORTED FIRES

Before proceeding with the quantitative analysis, it should be pointed out that a potentially important problem with the data base involves bias in the reporting of fires. Examination of the data base shows that some of the fires reported in the Electric Power Research Institute analysis (Reference 4-2) are not included in Nuclear Power Experience (NPE) (Reference 4-3). The fires not picked up by NPE were apparently not believed to be of safety significance; their omission indicates a filtering process for fire reporting. Further, it is not overly speculative to assume that, at least at some plants, there is a filtering process with regard to reporting fires to insurance companies.

Two incidents provide further evidence of this filtering. The first involves precursor events to the Browns Ferry cable spreading room fire; the NPE narrative for the event indicates that a number of small fires were started by the leak-testing procedure before the serious fire occurred. These fires were immediately extinguished and not reported. A second incident involved a set of six small welding fires (in the switchgear room) occurring at a particular plant in the space of a month. Although these fires were picked up by NPE, it should be noted that such multiple occurrences are not reported for any other plant (for any location within the plant). There is no particular reason to believe that this particular plant is unique.

From a risk standpoint, the potentially optimistic bias introduced by the filtering of fires during operation or shutdown may not be large since the unreported fires, by their nature, are generally small and immediately extinguished. In this study, therefore, no adjustments are made to the data or estimation process to account for bias in event reportage. This is consistent with approaches used in earlier fire risk studies (e.g., Reference 4-4); further study of this problem, however, may be worthwhile.

4.4 TREATMENT OF CONSTRUCTION FIRES

The data base contains numerous fire events that occurred during construction or preoperational testing. A small number of these events are judged applicable to the analysis; because of the relatively small size of the data base, these events are also included in the analyses of $\lambda_{i,sd}$, $\lambda_{i,sd/op}$, and $\lambda_{i,op}$.

To formally account for these fires in the estimation process, data are needed not only for the number of occurrences but also for the relevant exposure time. Thus, it must be determined how long the plant suffering the fire was in a configuration (during construction or preoperational testing) similar to its configuration during shutdown or operation. Further, it must also be determined how long other plants in the data base not experiencing fires were in similar configurations.

In general, it is believed that the plant configuration during construction and testing only approaches the operation/shutdown configuration during the very last stages. As a result, the exposure times are likely to be on the order of 1 to 3 years.

Because of this judgment, the small number of fires in this class, and the risk-centered context of this analysis, a slightly conservative approach is adopted instead of the formal approach. The fire occurrences are added to the data base, but no additional time is added to the exposure time used in the analyses of $\lambda_{i,sd}$, $\lambda_{i,sd/op}$, and $\lambda_{i,op}$.

4.5 CONTROL ROOM FIRE FREQUENCY

Section 3 shows that four control room fires are included in the data base; two occurred at Hatch Unit 1, one occurred at Dresden, and one occurred at Three Mile Island Unit 2. All four fires are judged relevant to both shutdown and operation.

Using these data with the prior distribution for (μ_{CR}, σ_{CR}) shown in Figure 4-1 and the control room exposure time data by plant site and room-years of exposure, the resulting distributions for $\lambda_{CR,sd}$ and $\lambda_{CR,sd/op}$ are characterized in Figure 4-2 and Table 4-1. The prior distribution, as is the case throughout this analysis, is chosen to cover a wide range of μ and σ values. In particular, the grid for μ is selected to account for the order of magnitude uncertainties in λ (recall that e^{μ} is the median of the population variability distribution for λ if μ and σ are known). The weights assigned to each (μ, σ) pair are uniform, reflecting relative ignorance and avoiding strong bias before the introduction of data.

Regarding the control room exposure time, it should be noted that while some multiple unit sites share control rooms, this analysis assumes that each unit has a separate room. This approach, which is also used for the cable spreading room, is justified by the functional separation of the control areas (the single room is essentially two rooms joined together without a wall).

Figure 4-2 and Table 4-1 also characterize the distribution for the total control room fire frequency, λ_{CR}, which is just the sum of the previous two uncertain variables. Also provided is the distribution obtained in Reference 4-5. Note that this latter is based on an earlier data base (including fires up through December 1981), and a different two-stage Bayes' grouping (plants instead of sites), and is for fires during operation rather than shutdown.

As discussed earlier in this section and in Section 1, the fire frequencies developed in this report are given in terms of fires per shutdown year, while the frequencies presented in Reference 4-5 are in terms of fires per operating year.

Table 4-1 shows that the Reference 4-5 results are comparable to the results obtained for $\lambda_{CR,sd/op}$. The difference in overall results is due to the inclusion of the class of control room fires that may occur only during shutdown; because of the lack of data for these fires, the difference, in terms of mean values, is not large. It should also be noted that the distributions obtained in this study are narrower than those obtained in Reference 4-5 (the latter has 5th percentiles down to 10^{-7} per year). The narrowing of the distributions is due to both an increased amount of data (occurrences and exposure time) and the site-to-site variability modeling approach adopted, rather than the plant-to-plant modeling approach of Reference 4-5.

Figure 4-2 and Table 4-1 also show the analogous results for λ^*_{CR}, the frequency of control room fires during operation. Because none of the control room fires experienced so far belong in the "operation only" category, there is little difference between λ^*_{CR} and λ^*_{CR} (they both share $\lambda_{sd/op}$); the difference observed is caused by the larger amount of operating experience (versus shutdown experience).

4.6 CABLE SPREADING ROOM FIRE FREQUENCY

The data base contains three cable spreading room fires. One fire is the well-known Browns Ferry fire of 1975, one occurred at Peach Bottom 3, and one is not attributed to any particular plant. All three fires are judged relevant to shutdown and operation.

Using the prior distribution shown in Figure 4-3 for (μ_{CSR},σ_{CSR}), the same exposure data as that for the control room, and the methodology for treating unattributed fires discussed earlier in this section, the distributions for $\lambda_{CSR,sd}$ and $\lambda_{CSR,sd/op}$ are obtained (see Figure 4-4 and Table 4-2).

Figure 4-4 and Table 4-2 also characterize the distribution for the total cable spreading room fire frequency, λ_{CSR}, and provide a comparison with the distribution obtained in Reference 4-5. The decrease in mean frequency is caused by the decrease in the 95th percentile, which, in turn, is caused by the increased site-specific experience available without cable spreading room fires. For example, recall that in the analysis of Reference 4-5 the Browns Ferry fire represents evidence of the form: one fire in less than 1 cable spreading room year. In this analysis, which is performed a number of years later and which lumps the experience of Units 1, 2, and 3 together, the data now are of the form: one fire in 35.58 cable spreading room years.

It is believed that the site-to-site variability model represents the variability in fire occurrence rates more accurately than does the plant-to plant variability model of Reference 4-5. The narrower distributions for control room and cable spreading room fire occurrence rates obtained in this report are a direct outcome of this more realistic approach and the incorporation of more data; i.e., stronger evidence.

Figure 4-4 and Table 4-2 also show the results for λ^*_{CSR}. As in the case of control room fires, the small difference between λ_{CSR} and λ^*_{CSR} is because of the slightly larger amount of operating experience available (which leads to a $\lambda_{CSR,op}$ that is smaller than $\lambda_{CSR,sd}$).

4.7 AUXILIARY BUILDING FIRE FREQUENCY

Table 3-2 shows that there are 43 auxiliary/control building fires in the data base applicable during shutdown or operation and that there are 12 applicable during shutdown only. Of the 43 fires, 2 are not included in the quantititative analysis (incident numbers 271 and 368) because their respective plants had not yet entered commercial operation. Of the latter 12, only 7 are used as data points (the 6 switchgear room welding fires are treated as a single event).

The prior distribution for (μ_{AUX},σ_{AUX}) used in the analysis is shown in Figure 4-5. As is the case for all locations considered in this study, the prior distribution is broad enough to accommodate a wide range of possible values for μ and σ; it is also uniformly weighted to avoid strong bias prior to the introduction of data. Using the methodology for treating unattributed fires discussed earlier

(11 shutdown operation fires and 2 shutdown only fires are unattributed), the distributions for $\lambda_{AUX,sd}$ and $\lambda_{AUX,sd/op}$ are obtained (see Figure 4-6 and Table 4-3).

As in the case of the control room analysis, the auxiliary building fire frequency computed in Reference 4-5 compares favorably with $\lambda_{AUX,sd/op}$. It also compares favorably with the updated operating fire frequency, λ^*_{AUX}. This is because the frequency of fires during operation only is relatively small.

4.8 TURBINE BUILDING FIRE FREQUENCY

Table 3-3 shows that there are 12 turbine building fires in the data base applicable during shutdown or operation, 7 that are applicable during shutdown only, and 17 that are applicable during operation only. The large number in the last category is caused by the operation of equipment not normally used during shutdown; e.g., the main turbine generator.

The prior distribution for (μ_{TB},σ_{TB}) used in the analysis is shown in Figure 4-7. Using the methodology for treating unattributed fires discussed earlier (seven shutdown/operation fires and two shutdown-only fires are unattributed), the distributions for $\lambda_{TB,sd}$, $\lambda_{TB,sd/op}$, and $\lambda_{TB,op}$ are obtained (see Figure 4-8 and Table 4-4).

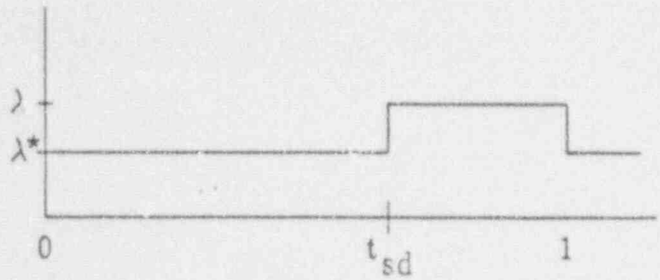
Figure 4-8 and Table 4-4 show that the turbine building fire frequency during operation, λ^*_{TB}, is slightly higher than the frequency during shutdown, ϕ_{TB}. The difference, however, is not as large as might be expected by comparing the 17 fires for operation only versus the 7 fires for shutdown only mentioned above. The small difference is because of the smaller amount of shutdown experience (0.3 per calendar year) compared with operating experience (0.7 per calendar year).

Figure 4-8 and Table 4-4 also show that both the updated λ_{TB} and the updated λ^*_{TB} are greater than the value predicted in Reference 4-5. This may be because of the larger number of data sources used in this study, as well as the greater amount of available plant experience.

4.9 CONCLUDING REMARKS

As shown in Section 3, the number of fires in the data base that are judged to be applicable only during operation is generally quite small, especially when off-gas system fires are ignored (these latter are not believed to significantly affect the overall risk). Thus, the results of Tables 4-1 through 4-3 and Figures 4-2, 4-4, and 4-6 indicate that the frequency of fires during shutdown is higher for the control room, cable spreading room, and auxiliary building than is the frequency of fires during power operation. The increase is simply because of the potential increase in activities (that may lead to fire) during shutdown. The higher frequency of fires during operation in the turbine building (see Table 4-4 and Figure 4-8) is caused by the operation of equipment not normally used during shutdown.

It should be cautioned that these results are given in terms of the frequency of fires per shutdown year. The time-dependent frequency of fires (for a given location) behaves as



where λ^* is the frequency during operation and λ is the frequency during shutdown, assuming that the reactor is shut down at $t = t_{sd}$ and resumes operation at $t = 1$ year. As a result, the expected number of shutdown fires per calendar year is given by

$$E[N_{sd}] = \lambda\phi_{sd} \tag{4.7}$$

where

λ = frequency of fires per shutdown year.

ϕ_{sd} = fraction of calendar year reactor is shut down.

A simple procedure for estimating the annual frequency of shutdown fires that has been suggested prior to this study is to multiply the results of Reference 4-5, which represent the fire frequency during operation (λ^*), by ϕ_{sd}. Equation (4.5) shows that a correct result will be obtained only if $\lambda^* = \lambda$, or, in other words, if the frequency of fires that may only occur during shutdown is equal to the frequency of fires that may only occur during operation. The results of this study indicate that, except for the cable spreading room, the suggested approach is nonconservative; the degree of nonconservatism is illustrated in Figure 4-9 (it is assumed that ϕ_{sd} = 0.30).

4.10 REFERENCES

4-1. Kaplan, S., "On a "Two-Stage" Bayesian Procedure for Determining Failure Rates from Experiential Data," Institute of Electrical and Electronics Engineers Transactions on Power Apparatus and Systems, Vol. PAS-102, No. 1, January 1983.

4-2. Dungan, K. W., and M. S. Lorenz, "Nuclear Power Plant Fire Loss Data," prepared for the Electric Power Research Institute, Professional Loss Control, Inc., EPRI-NP-3179, 1983.

4-3. S. M. Stoller Corporation, Nuclear Power Experience, 1986.

4-4. Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment," prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983.

4-5. Kazarians, M., and G. Apostolakis, "Modeling Rare Events: The Frequencies of Fires in Nuclear Power Plants," Proceedings of Workshop on Low Probability/High Consequence Risk Analysis, Society for Risk Analysis, Arlington, Virginia, 1983.

TABLE 4-1. CONTROL ROOM FIRE FREQUENCY

Plant Mode	Mean	Standard Deviation	5th Percentile	50th Percentile	95th Percentile
Shutdown Only	1.5-3	6.5-3	1.5-5	2.8-4	4.2-3
Shutdown/Operation	4.6-3	1.4-2	1.9-5	1.2-3	1.3-2
TOTAL SHUTDOWN	6.3-3	1.6-2	2.1-4	2.5-3	2.4-2
Operation Only	9.2-4	3.8-3	1.8-5	2.1-4	2.4-3
TOTAL OPERATION	5.6-3	1.4-2	2.0-4	2.2-3	2.1-2
Reference 4-5*	4.9-3	Not Applicable	1.3-7	2.2-4	1.5-2

*Reference 4-5 analysis is based on fires in operating plants up through December 1981. Plant-to-plant variability is modeled in that analysis, rather than site-to-site variability (the latter is treated in this study).

NOTE: Exponential notation is indicated in abbreviated form; i.e., 1.5-3 = 1.5×10^{-3}.

TABLE 4-2. CABLE SPREADING ROOM FIRE FREQUENCY

Plant Mode	Mean	Standard Deviation	5th Percentile	50th Percentile	95th Percentile
Shutdown Only	1.5-3	6.5-3	1.5-5	2.8-4	4.2-3
Shutdown/Operation	4.1-3	2.6-2	6.6-6	9.5-4	9.6-3
TOTAL SHUTDOWN	5.6-3	2.7-2	1.7-4	2.0-3	1.4-2
Operation Only	9.2-4	3.8-3	1.8-5	2.1-4	2.4-3
TOTAL OPERATION	4.7-3	2.1-2	1.4-4	1.8-3	1.2-2
Reference 4-5*	6.7-3	Not Applicable	7.0-7	7.0-4	2.2-2

*Reference 4-5 analysis is based on fires in operating plants up through December 1981. Plant-to-plant variability is modeled in that analysis, rather than site-to-site variability (the latter is treated in this study).

NOTE: Exponential notation is indicated in abbreviated form; i.e., 1.5-3 = 1.5×10^{-3}.

TABLE 4-3. AUXILIARY BUILDING FIRE FREQUENCY

Plant Mode	Mean	Standard Deviation	5th Percentile	50th Percentile	95th Percentile
Shutdown Only	3.0-2	8.2-2	1.2-4	1.0-2	1.0-1
Shutdown/Operation	4.2-2	7.1-2	1.8-3	2.4-2	1.1-1
TOTAL SHUTDOWN	7.2-2	1.1-1	6.1-3	5.0-2	2.0-1
Operation Only	7.7-3	3.4-2	7.1-5	1.7-3	2.0-2
TOTAL OPERATION	5.1-2	7.7-2	4.7-3	3.3-2	1.4-1
Reference 4-5*	4.8-2	Not Applicable	5.6-3	3.5-2	1.3-1

*Reference 4-5 analysis is based on fires in operating plants up through December 1981. Plant-to-plant variability is modeled in that analysis, rather than site-to-site variability (the latter is treated in this study).

NOTE: Exponential notation is indicated in abbreviated form; i.e., 3.0-2 = 3.0×10^{-2}.

TABLE 4-4. TURBINE BUILDING FIRE FREQUENCY

Plant Mode	Mean	Standard Deviation	5th Percentile	50th Percentile	95th Percentile
Shutdown Only	2.4-2	7.6-2	3.6-5	5.7-3	6.9-2
Shutdown/Operation	2.1-2	7.6-2	1.0-4	7.4-3	5.4-2
TOTAL SHUTDOWN	4.5-2	1.1-1	9.9-4	1.9-2	1.5-1
Operation Only	2.5-2	6.5-2	2.6-4	8.3-3	9.0-2
TOTAL OPERATION	4.7-2	1.0-1	2.2-3	2.1-2	1.6-1
Reference 4-5*	1.6-2	Not Applicable	1.0-4	1.0-2	7.0-2

*Reference 4-5 analysis is based on fires in operating plants up through December 1981. Plant-to-plant variability is modeled in that analysis, rather than site-to-site variability (the latter is treated in this study).

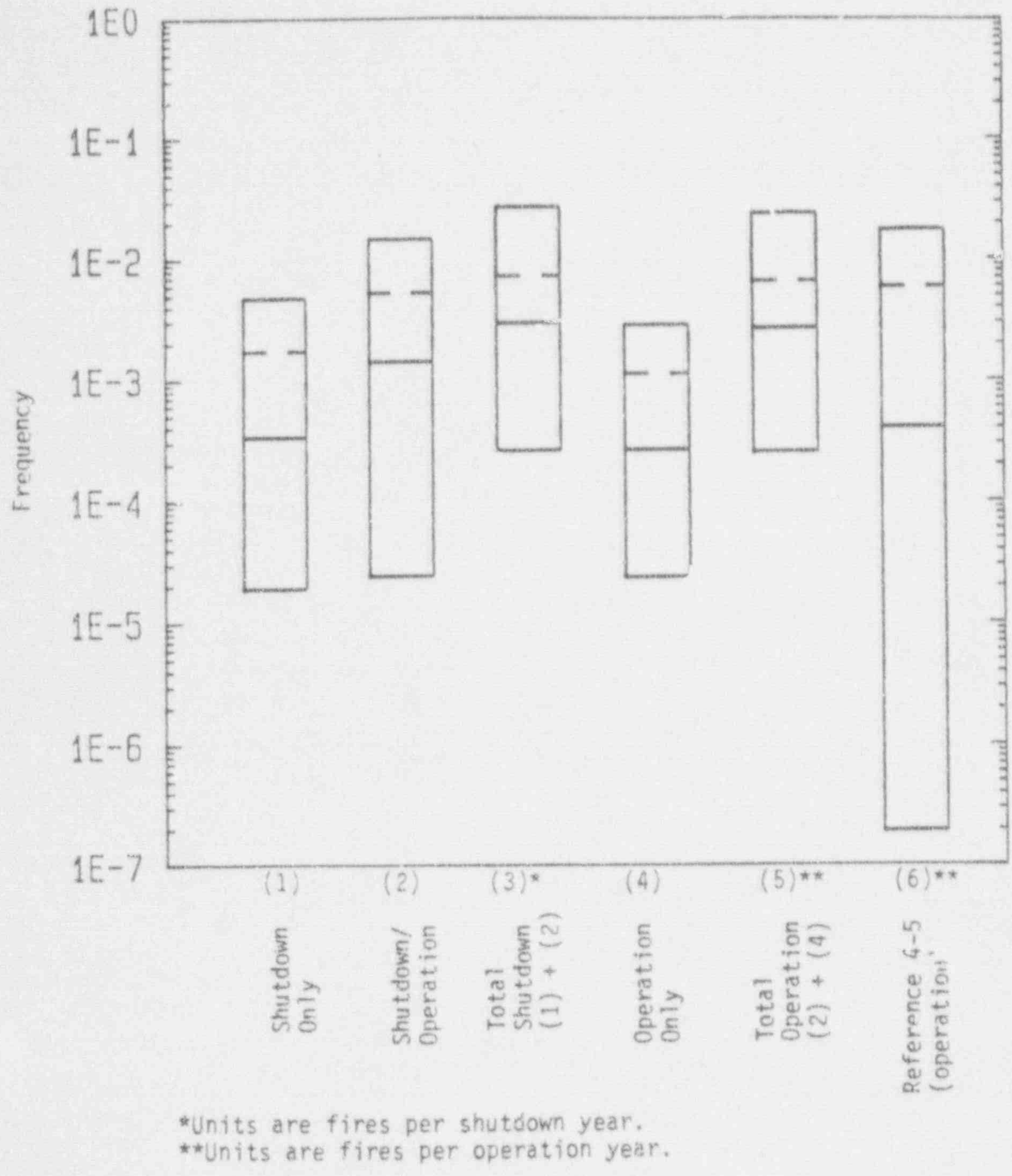
NOTE: Exponential notation is indicated in abbreviated form; i.e., 2.4-2 = 2.4×10^{-2}.

i	e^{μ_i}	j	σ_j
1	1.00-4	1	1.00-1
2	1.78-4	2	3.00-1
3	3.16-4	3	5.00-1
4	5.62-4	4	7.00-1
5	1.00-3	5	9.00-1
6	1.78-3	6	1.10+0
7	3.16-3	7	1.30+0
8	5.62-3	8	1.50+0
9	1.00-2	9	1.70+0
10	2.15-2	10	1.90+0
		11	2.10+0
		12	2.30+0
		13	2.50+0

NOTES:

1. Probability weights for each combination of (e^{μ_i}, σ_j) are constant.
2. Exponential notation is indicated in abbreviated form; i.e., 1.00-4 = 1.00×10^{-4}.

FIGURE 4-1. PRIOR DISTRIBUTION GRID FOR μ_{CR} AND σ_{CR}



*Units are fires per shutdown year.
**Units are fires per operation year.

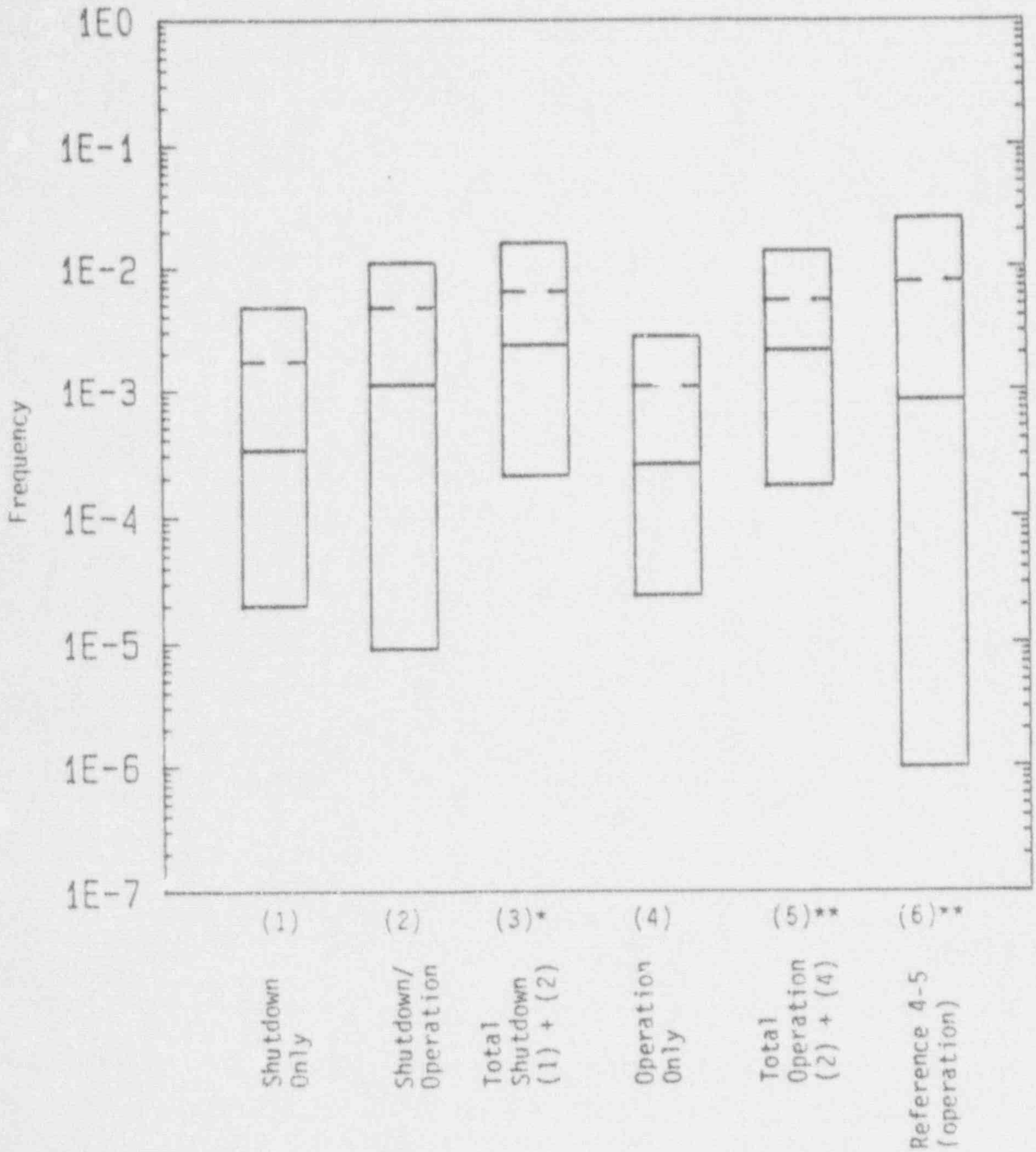
FIGURE 4-2. CONTROL ROOM FIRE FREQUENCY

i	e^{μ_i}	j	σ_j
1	1.00-5	1	5.00-2
2	1.78-5	2	4.00-1
3	3.16-5	3	7.00-1
4	5.62-5	4	9.00-1
5	1.00-4	5	1.10+0
6	1.78-4	6	1.30+0
7	3.16-4	7	1.50+0
8	5.62-4	8	1.70+0
9	1.00-3	9	1.90+0
10	1.78-3	10	2.10+0
11	3.16-3	11	2.30+0
12	5.62-3	12	2.60+0
		13	3.50+0

NOTES:

1. Probability weights for each combination of (e^{μ_i}, σ_j) are constant.
2. Exponential notation is indicated in abbreviated form; i.e., 1.00-5 = 1.00×10^{-5}.

FIGURE 4-3. PRIOR DISTRIBUTION GRID FOR μ_{CSR} AND σ_{CSR}



*Units are fires per shutdown year.
**Units are fires per operation year.

FIGURE 4-4. CABLE SPREADING ROOM FIRE FREQUENCY

Shutdown Only

i	e^{μ_i}	j	σ_j
1	1.00-7	1	5.00-2
2	1.00-6	2	4.00-1
3	1.00-5	3	7.00-1
4	3.16-5	4	9.00-1
5	1.00-4	5	1.10+0
6	2.15-4	6	1.30+0
7	4.64-4	7	1.50+0
8	1.00-3	8	1.70+0
9	1.78-3	9	1.90+0
10	3.16-3	10	2.10+0
11	5.62-3	11	2.30+0
12	1.00-2	12	2.60+0
13	1.78-2	13	3.20+0
14	3.16-2		
15	5.16-2		
16	1.00-1		

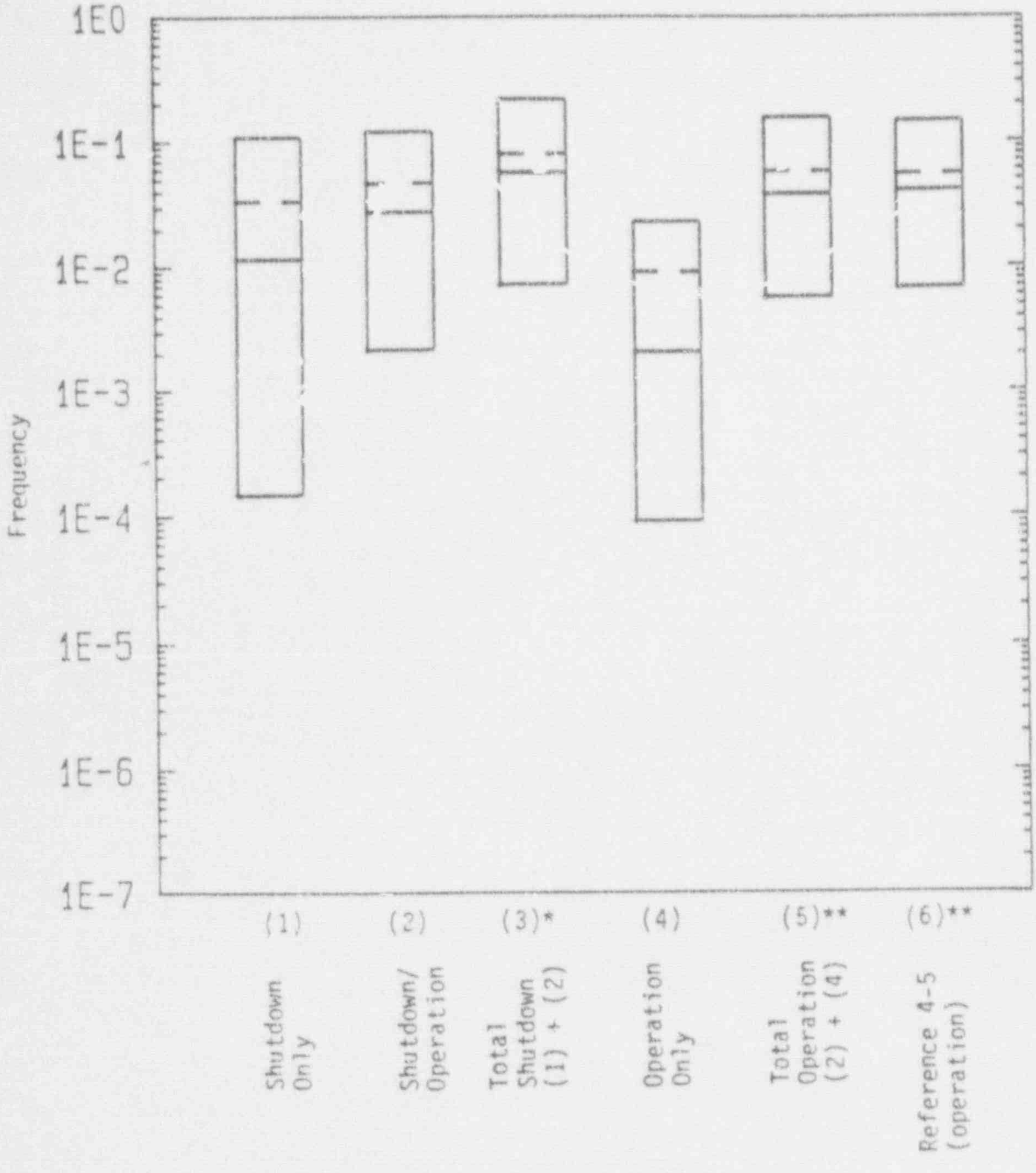
Shutdown and Operation

i	e^{μ_i}	j	σ_j
1	1.00-3	1	5.00-2
2	1.78-3	2	4.00-1
3	3.16-3	3	7.00-1
4	5.62-3	4	9.00-1
5	1.00-2	5	1.10+0
6	1.78-2	6	1.30+0
7	3.16-2	7	1.50+0
8	5.62-2	8	1.70+0
9	1.00-1	9	1.90+0
10	2.15-1	10	2.10+0
11	4.64-1	11	2.30+0
12		12	2.60+0

NOTES:

1. [illegible]bility weights for each combination of (e^{μ_i}, σ_j) are constant.
2. [illegible]ponential notation is indicated in abbreviated form; i.e., 1.00-7 = 1.00×10^{-7}.

FIGURE 4-5. PRIOR DISTRIBUTION GRID FOR μ_{AUX} AND σ_{AUX}



*Units are fires per shutdown year.
**Units are fires per operation year.

FIGURE 4-6. AUXILIARY BUILDING FIRE FREQUENCY

Shutdown Only

i	e^{μ_i}	j	σ_j
1	1.00-7	1	1.09+0
2	1.00-6	2	1.93+0
3	1.00-5	3	3.16+0
4	3.16-5	4	4.40+0
5	1.00-4	5	6.11+0
6	2.15-4	6	8.49+0
7	4.64-4	7	1.18+1
8	1.00-3	8	1.64+1
9	1.78-3	9	2.28+1
10	3.16-3	10	3.16+1
11	5.62-3	11	4.40+1
12	1.00-2	12	7.20+1
13	1.78-2	13	1.93+2
14	3.16-2		
15	5.62-2		
16	1.00-1		

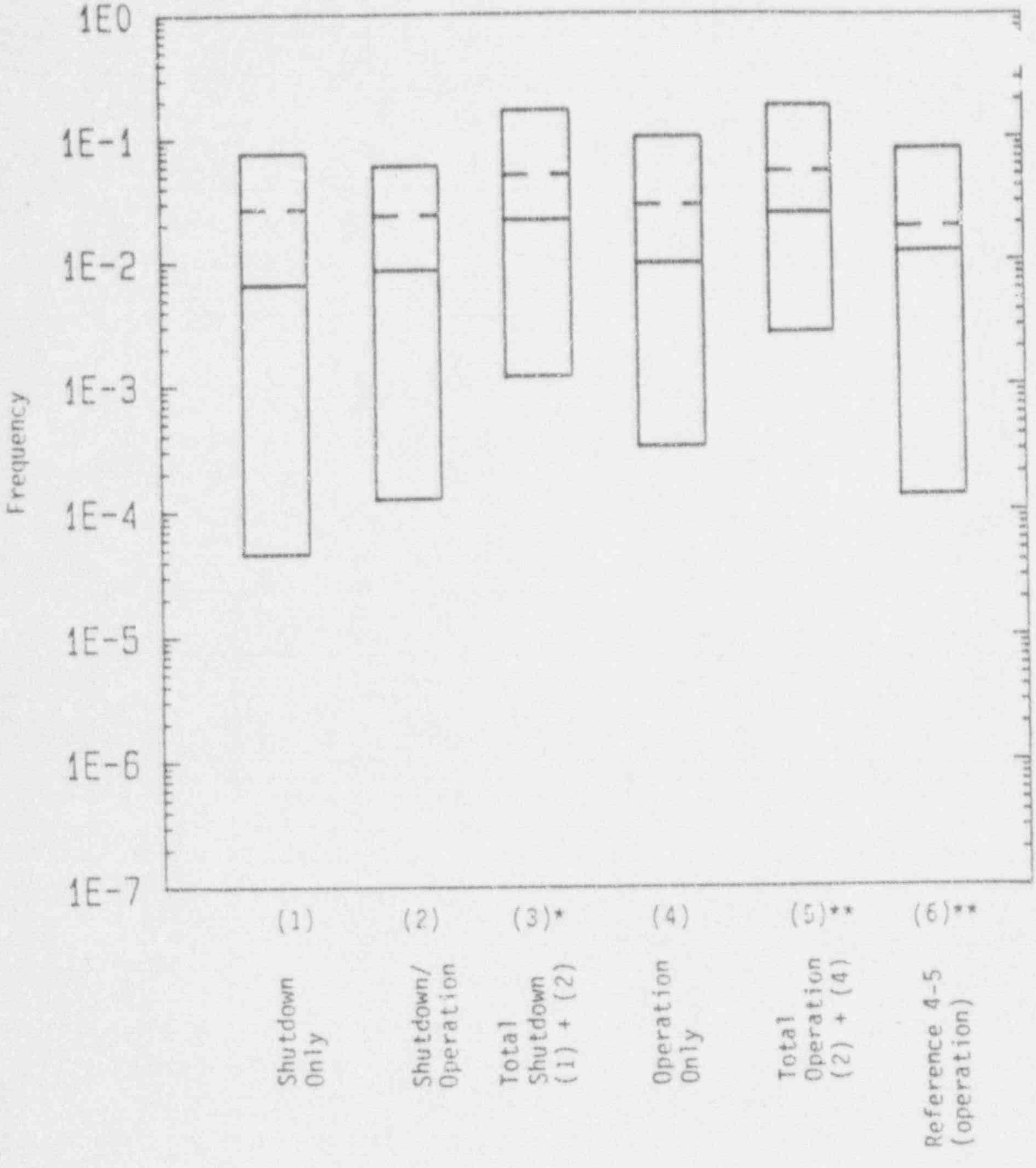
Shutdown and Operation

i	e^{μ_i}	j	σ_j
1	1.00-3	1	1.09+0
2	1.78-3	2	1.93+0
3	3.16-3	3	3.16+0
4	5.62-3	4	4.40+0
5	1.00-2	5	6.11+0
6	1.78-2	6	8.49+0
7	3.16-2	7	1.18+1
8	5.62-2	8	1.64+1
9	1.00-1	9	2.28+1
10	2.15-1	10	3.16+1
11	4.64-1	11	4.40+1
12		12	7.20+1

NOTES:

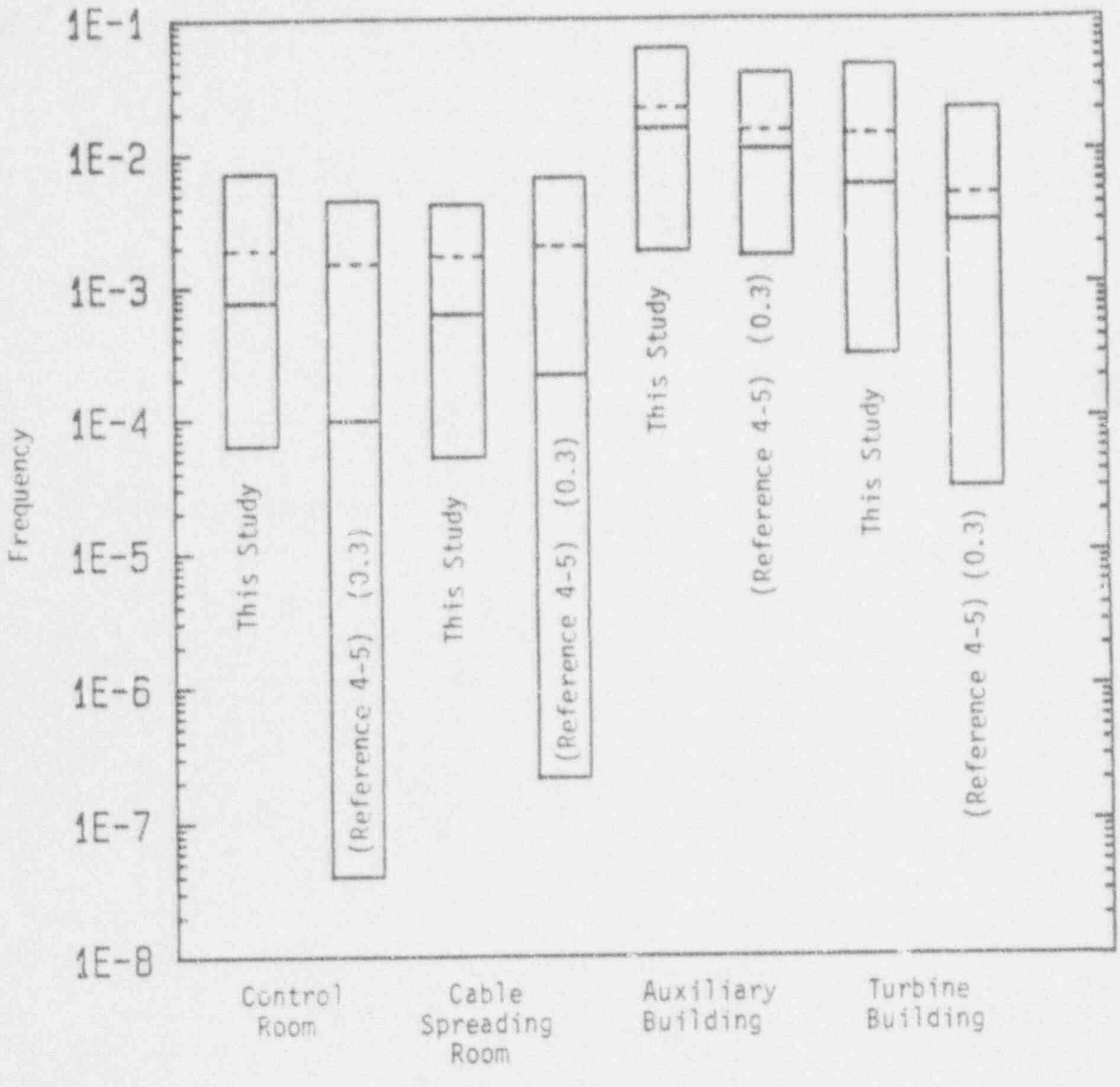
1. Probability weights for each combination of (e^{μ_i}, σ_j) are constant.
2. Exponential notation is indicated in abbreviated form; i.e., $1.00\text{-}7 = 1.00 \times 10^{-7}$.

FIGURE 4-7. PRIOR DISTRIBUTION GRID FOR μ_{TB} AND σ_{TB}



*Units are fires per shutdown year.
**Units are fires per operation year.

FIGURE 4-8. TURBINE BUILDING FIRE FREQUENCY



NOTE: Reference 4-5 results are in terms of fires per operating year.

Legend:
95th Percentile
Mean
50th Percentile
5th Percentile

FIGURE 4-9. ANNUALIZED FIRE FREQUENCIES (SHUTDOWN FIRES PER CALENDAR YEAR)

APPENDIX E

ANALYSIS OF FLOOD FREQUENCY DURING SHUTDOWN

PLG-0624

INTERNAL FLOOD FREQUENCIES DURING SHUTDOWN AND OPERATION FOR NUCLEAR POWER PLANTS

Project Manager

Karl N. Fleming

Principal Investigators

Vicki M. Bier
William A. Bromley
Mardyros Kazarians
Paul H. Raabe

Prepared for
NEW HAMPSHIRE YANKEE
Seabrook, New Hampshire
May 1988

PLG Pickard, Lowe and Garrick, Inc.

Newport Beach ■ CA
Washington ■ DC

ENGINEERS ■ APPLIED SCIENTISTS ■ MANAGEMENT CONSULTANTS

CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

The objective of this work is to estimate the frequencies of internal floods in U.S. nuclear power plants during periods of both operation and shutdown using the most recent data available. This investigation, which is part of a larger study of the risks of accidents during shutdown, will help to determine the risk of floods during periods of plant shutdown. A byproduct is an up-to-date assessment of the flood frequency in all modes of plant operation from a spectrum of initiating events at Seabrook Station.

To obtain estimates of flood frequencies during both shutdown and plant operation, it was necessary to analyze the available data in greater detail than is usually done to support estimates of flood frequencies during plant operation alone. One of the by-products of this work, therefore, is a detailed reclassification of relevant flood occurrences. This analysis supersedes that presented in the Seabrook Probabilistic Safety Assessment (Reference 1-1).

This section outlines the data and methodology employed in this study and presents a brief summary of the results. Additional details on the data sources, the resulting data base, and the methodology used in this analysis are given in Sections 2, 3, and 4, respectively.

1.1 BASIC APPROACH

To better understand the flood frequencies estimated in this study, it is necessary to briefly describe the basic model that was used. Any model for the frequency of floods in a particular area must, of course, be capable of representing the effects of such factors as: the types of water systems that are present in that area, the types of operations and maintenance functions that are typically performed, and so on. In this study, the variability associated with all of these characteristics is modeled by a single parameter, the flood location.

Four "locations" were judged to be of special interest for this study: the auxiliary building, the turbine building, the circulating water system, and the service water system. The auxiliary building and turbine building were considered as locations for possible flood sources, while the circulating water and service water systems are possible flood sources. The auxiliary building and the turbine building are important because a flood in one of those locations could not only cause an accident, but also damage the safety equipment that would be needed to mitigate the effects of the accident. For example, the auxiliary building at Seabrook contains the charging pumps and the component cooling water pumps. Similarly, the room connected to the turbine building contains vital electrical relay cabinets, the failure of which could effectively lead to a loss of offsite power and station blackout. By contrast, the circulating water and service water systems are important flood sources because they are both connected to virtually infinite sources of water. They can therefore cause extremely large floods, and their layout varies significantly from plant to plant.

Of course, the five categories selected for inclusion in this study are not mutually exclusive. For example, service water floods can affect the auxiliary building, and circulating water floods can affect the turbine building. Therefore, in using these frequencies, one must take into account the specific conditions of the plant layout and combine the proper frequencies to derive the flood frequencies for a particular building. This is further discussed in Section 1.2. Similarly, some turbine building floods were so large that they also affected the adjacent auxiliary building. Cases such as this were categorized according to the actual source of the flood, rather than assigned to multiple categories to reflect all the buildings that were affected. In one case, however, it was not possible to unambiguously assign an event to a single category. In particular, that flood originated in the spent fuel pool and affected both the auxiliary building and the turbine building. This event was included in the data for both the auxiliary building and the turbine building, so the flood frequencies for these two areas are not quite additive.

It seems likely that the overall risk associated with floods during plant shutdown (taking into account not only the frequency but also the consequences of such floods) is less than for floods occurring during periods of operation. In particular, floods that occur when a plant is shut down are likely to have less severe consequences. However, the frequency of floods could actually be greater during shutdown than during operation because of the effects of test and maintenance activities. Hence, both types of floods were evaluated in this study.

The study began with a detailed review of the available data on floods to develop a comprehensive and up-to-date flood data base. This part of the process is described in more detail in Section 2. The second step was to categorize the events in the data base. The events were grouped according to both location and size. Each reported flood was then put into one of three categories:

1. Floods that could only have occurred during shutdown.
2. Floods that could have occurred during either shutdown or operation.
3. Floods that could only have occurred during operation.

(Floods occurring during construction were placed in either category 1 or category 2, depending on whether they could have occurred at an operating plant.) Summary statistics for each category were obtained using dBASE III, a microcomputer data base management program.

Finally, the third step was the actual quantitative analysis of the data. The model that was used for this purpose is described in Section 1.2 below.

1.2 FLOOD FREQUENCY MODEL

For any given location i, this study modeled the frequency of floods during shutdown as the sum of those floods that could have occurred only during shutdown and those that could have occurred either during shutdown or during operation. This model can be represented by the equation

$$\lambda_i = \lambda_{i,sd/op} + \lambda_{i,sd} \qquad (1.1)$$

where λ_i represents the frequency of floods per year of plant shutdown. The subscripts in Equation (1.1) refer to the different categories of floods. Thus, for instance, $\lambda_{i,sd/op}$ represents the frequency of floods in location i that could have occurred during either shutdown or operation, while $\lambda_{i,sd}$ represents the frequency of floods that could only have occurred during plant shutdown.

Similarly, the flood frequency during operation was modeled as the sum of those floods that could occur only during operation and those that could occur either during shutdown or operation. This model can be represented by the equation.

$$\lambda_i^* = \lambda_{i,op} + \lambda_{i,sd/op} \tag{1.2}$$

where λ_i^* is in units of floods per year of plant operation. Each of the terms in Equations (1.1) and (1.2) was estimated from the available data base using a two-stage Bayesian analysis (Reference 1-2), as described in Section 4.

Once these results have been obtained, the total annual frequency of floods can then be computed as a weighted sum of the flood frequencies during shutdown and operation, as follows. Let ϕ_{sd} be the fraction of the year that a plant is in shutdown mode (typically about 0.30). Then, since λ_i is the frequency of floods during shutdown and λ_i^* is the frequency of floods during operation, the total annual frequency of floods, $\Lambda_{i,T}$, is given by the weighted average

$$\Lambda_{i,T} = \lambda_i^* (1 - \phi_{sd}) + \lambda_i \phi_{sd} \tag{1.3}$$

where the units of $\Lambda_{i,T}$ (the total flood frequency) are floods per calendar year.

Finally, the fraction of this total that occurs during shutdown (i.e., the frequency of shutdown floods during a typical calendar year) is given by the second term of Equation (1.3),

$$\Lambda_i = \lambda_i \phi_{sd} = (\lambda_{i,sd/op} + \lambda_{i,sd}) \phi_{sd} \tag{1.4}$$

The units of Λ_i are shutdown floods per calendar year, where a year is assumed to include a fraction ϕ_{sd} of shutdown time.

To establish the flood frequencies for turbine and auxiliary buildings, one should use a combination of the frequencies provided in this report. For example, for a turbine building that includes service water pumps, heat exchangers and piping, circulating water piping, and expansion joints, one may add to the turbine building flood frequency (the one that excludes circulating water and service water systems) a large fraction of the service water flood frequency and about a quarter of the circulating water flood frequency. For service water, a large fraction is recommended because this turbine building contains most of the flood causing components of the system. For circulating water, about a quarter of the frequency is recommended because only the expansion joints and some short legs of the pipes are present in this building.

If the turbine building can be regarded as "average" (i.e., it includes some service water and circulating water piping and components), one may use the frequency that includes service water and circulating water contributions.

1.3 SUMMARY OF RESULTS

Figures 1-1 through 1-5 show some key characteristics of the shutdown and operation flood frequency distributions (λ_i and λ_i^*, respectively) for each of the four locations considered in this study: the auxiliary building, the turbine building, the circulating water system, and the service water system. For the turbine building, two sets of frequencies are given: one excluding service water and circulating water events and one including these events. The results indicate that, for the locations studied in this analysis, the frequency of floods is only slightly higher during shutdown than during normal operation.

In particular, the number of shutdown-only floods in the data base is roughly comparable to the number of operation-only floods, and the exposure time for plant shutdown is somewhat smaller than for periods of operation. This provides evidence of a slightly higher flood frequency during plant shutdown. However, most the events in the data base could have occurred during either operation or shutdown, so the differential is fairly small.

Flood sizes were defined as follows. Small floods were taken to be those with a spill rate about 100 gpm. Medium floods involved spill rates of about 1,000 gpm, while large floods had spill rates of roughly 10,000 gpm. Finally, extra large floods were those with flow rates about 50,000 gpm. In the results shown in Figures 1-1 through 1-5, "≥ small" is interpreted to include all floods, "≥ medium" includes floods of at least medium size, and "≥ large" includes only large or extra-large floods.

It should be noted here that the results of this study are based only on reported floods. As discussed in Section 4, the number of reported floods might be somewhat lower than the number that have actually occurred to date. However, the unreported floods are likely to be relatively small in size and, therefore, of less importance to plant risk. Although future studies may wish to consider the issue of unreported floods in greater detail, the flood frequencies presented in this study are likely to be adequate for use in most flood risk assessments.

1.4 REFERENCES

1-1. Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment," prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983.

1-2. Kaplan, S., "On a 'Two Stage' Bayesian Procedure for Determining Failure Rates from Experiential Data," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-102, No. 1, January 1983.

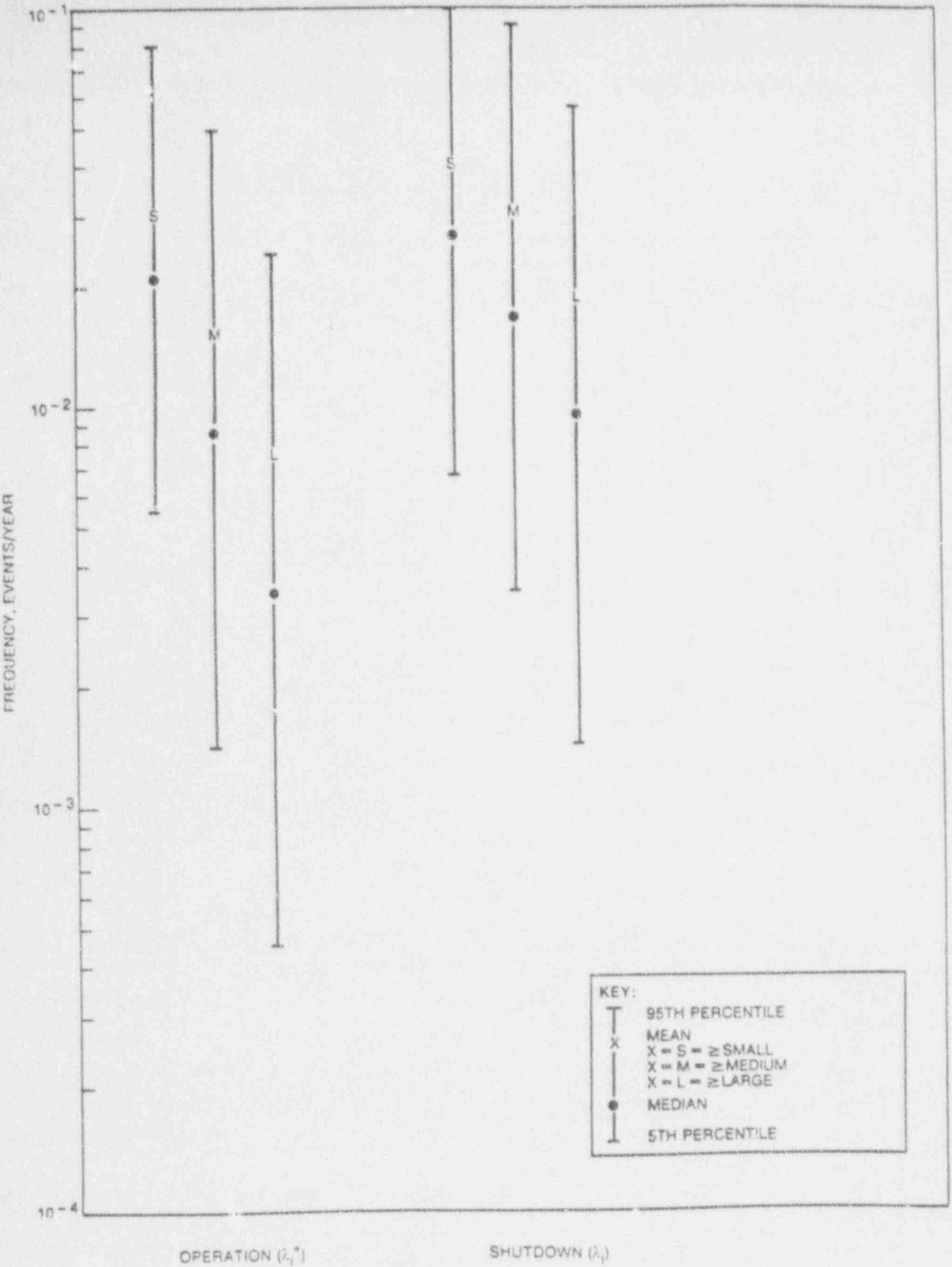


Figure 1-1. Auxiliary Building Flood Frequencies

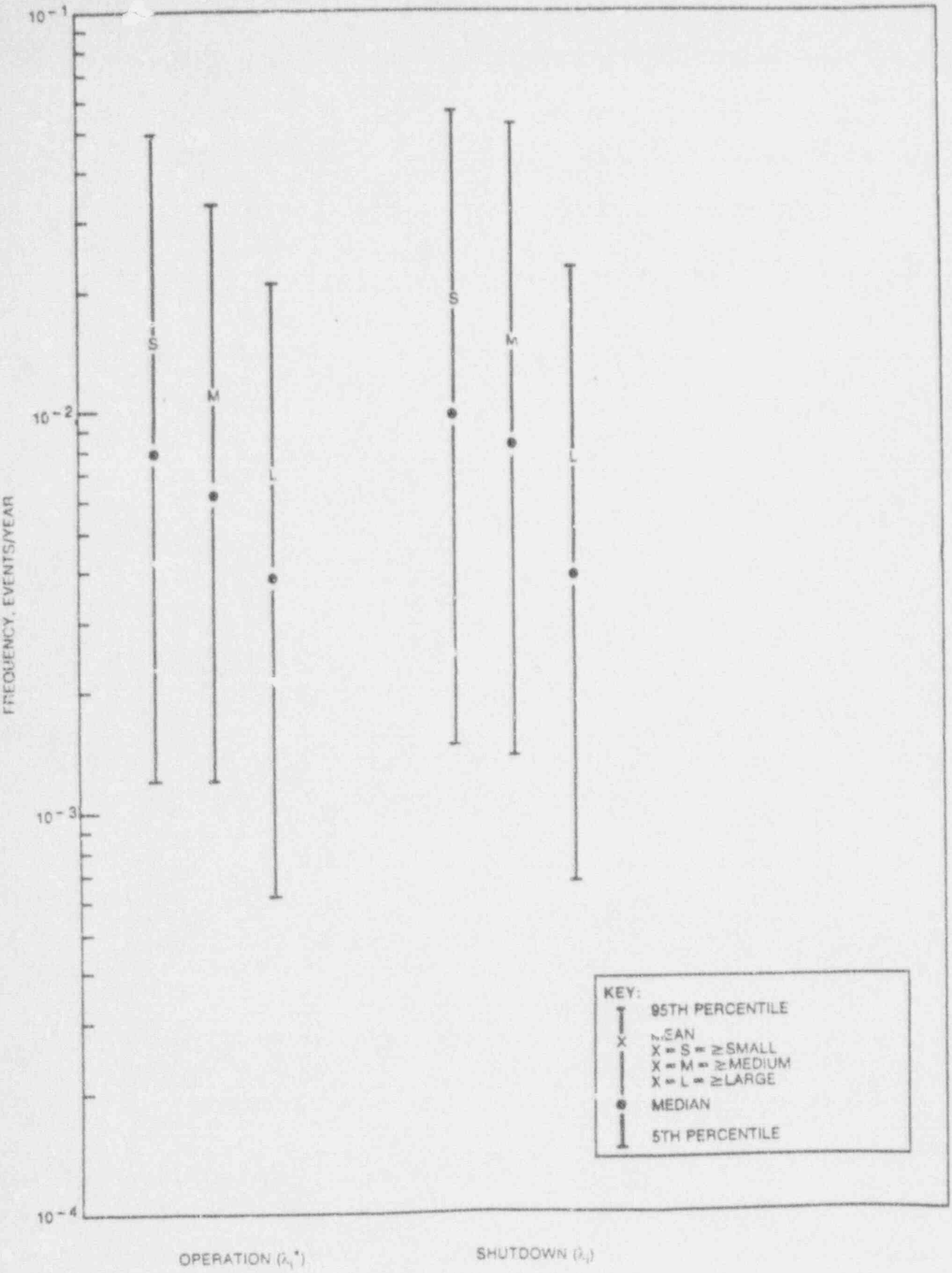


Figure 1-2. Turbine Building Flood Frequencies Excluding Service Water and Circulating Water-Related Events

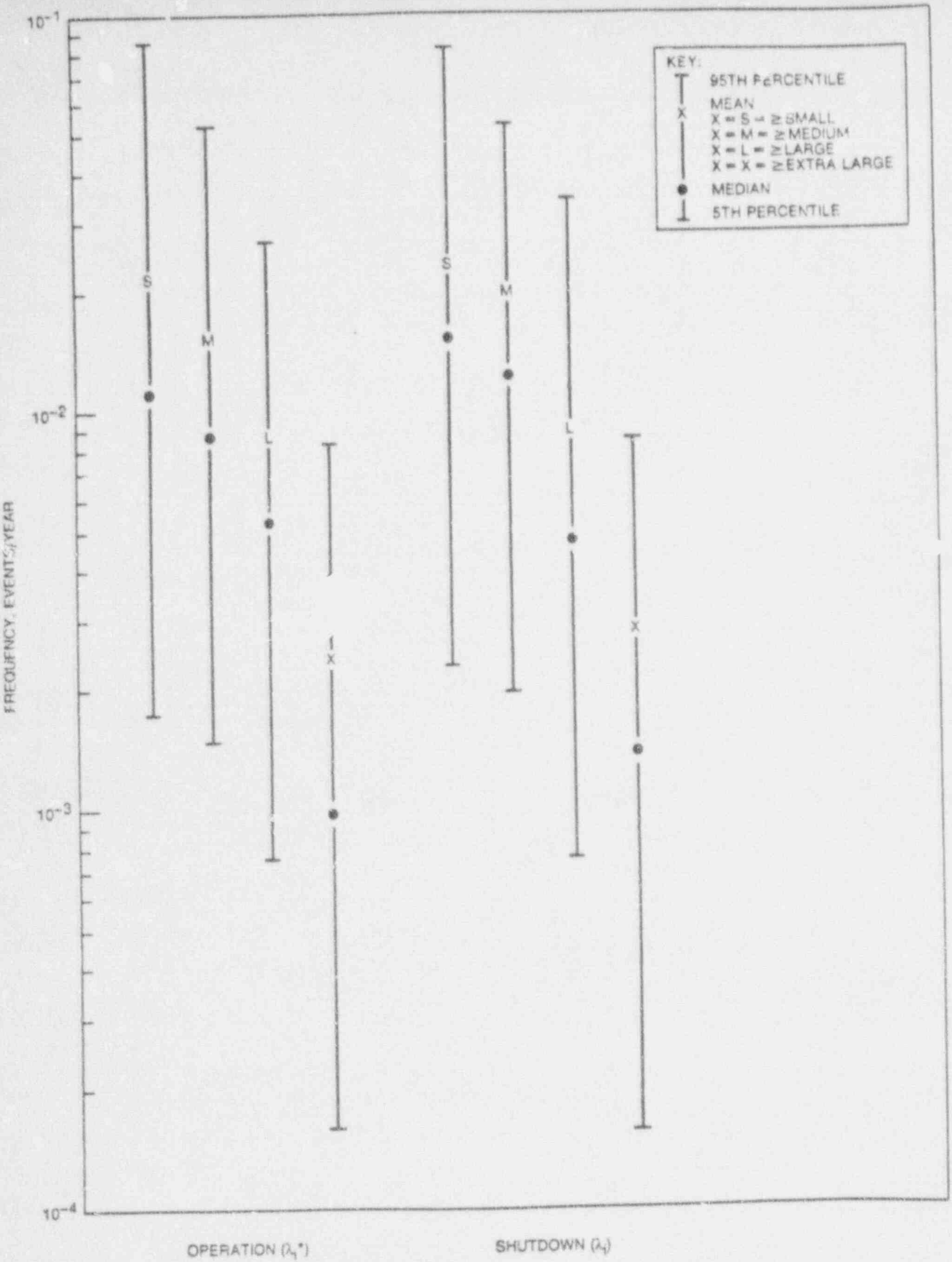


Figure 1-3. Turbine Building Flood Frequencies Including Service Water and Circulating Water-Related Events

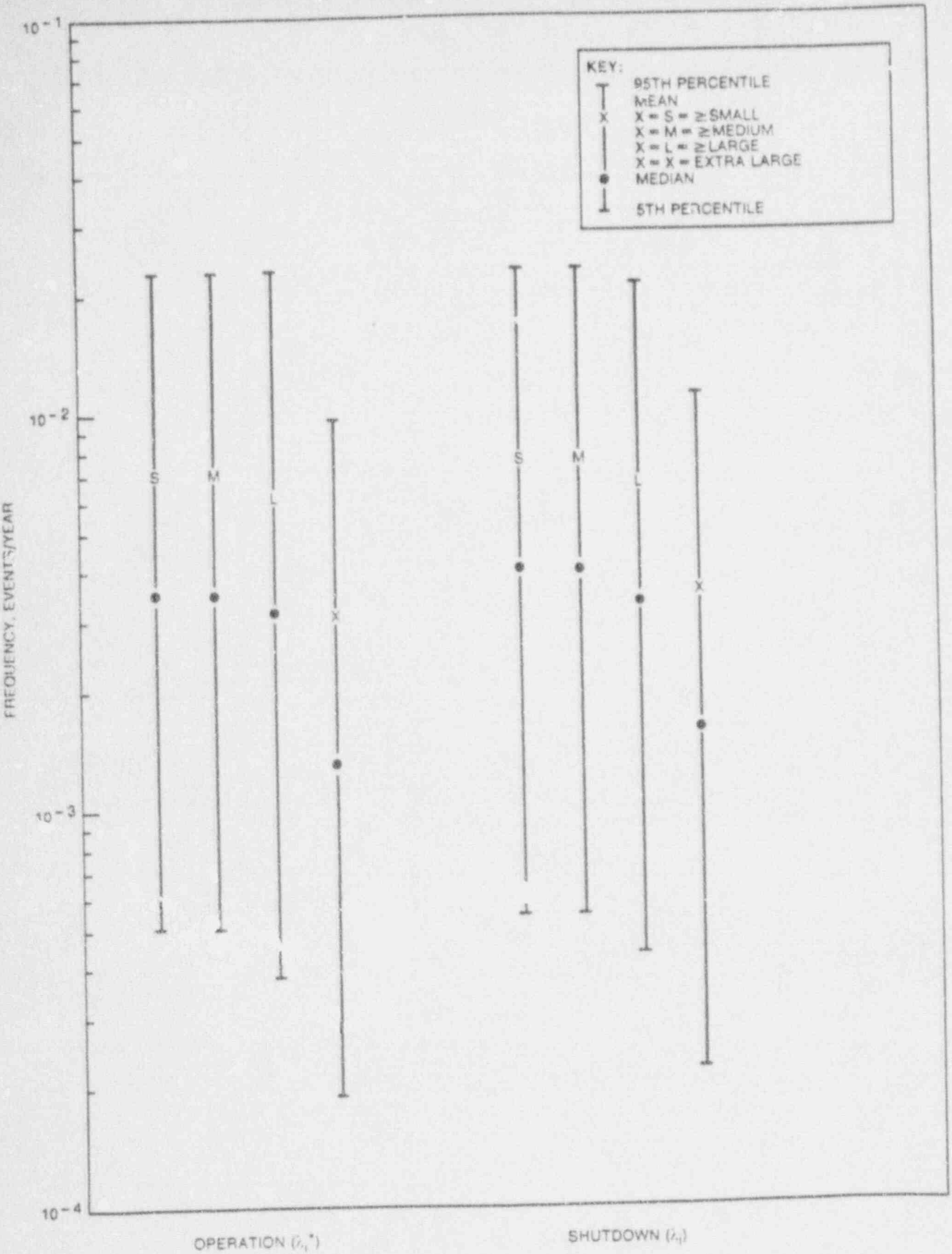


Figure 1-4. Circulating Water System Flood Frequencies

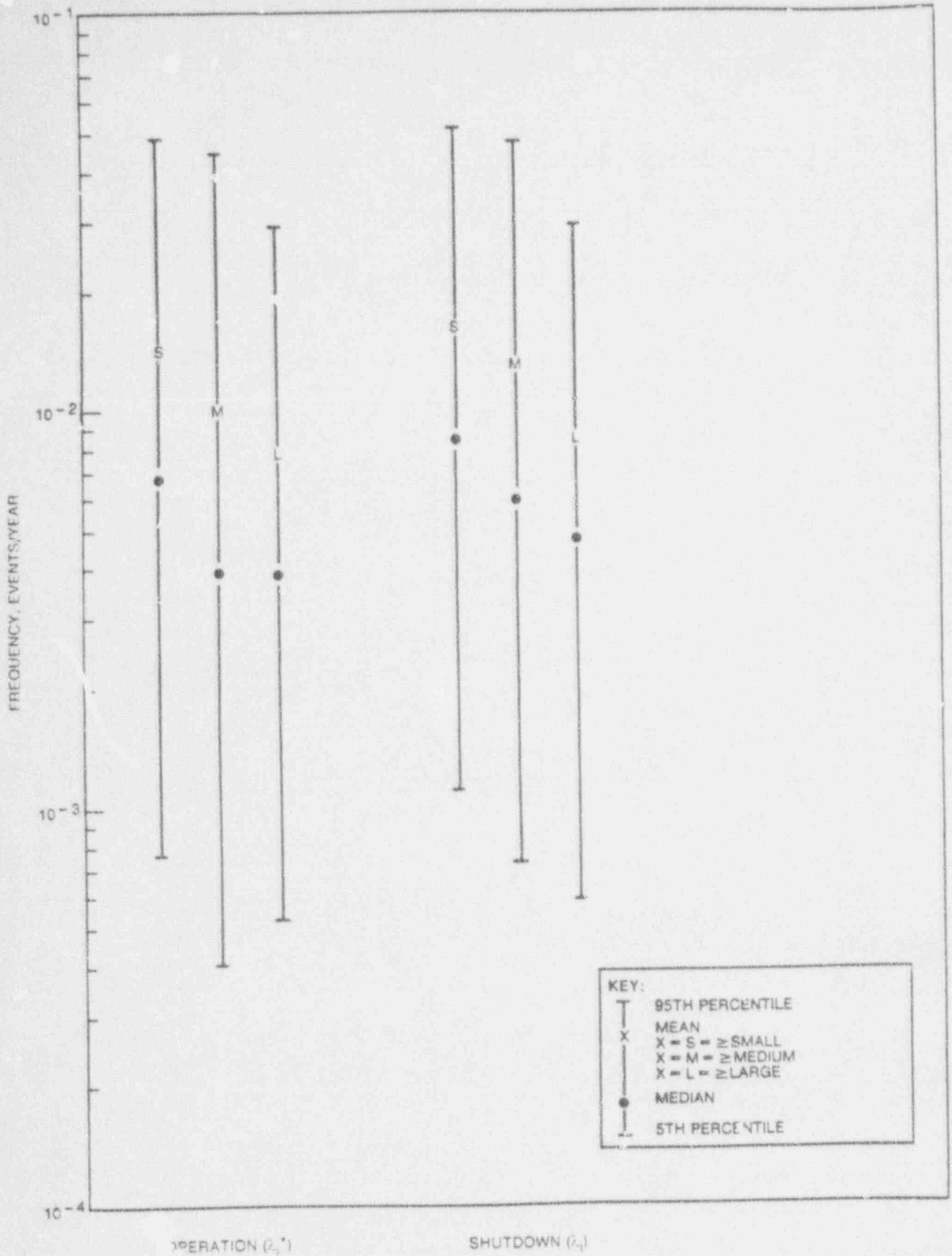


Figure 1-5. Service Water System Flood Frequencies

2. FLOOD DATA SOURCES

The basic data source used in this study was *Nuclear Power Experience* (NPE) (Reference 2-1). NPE is a periodic compilation of reportable events occurring at nuclear power plants, based primarily on Licensee Event Reports; its purpose is to provide a vehicle for sharing industry experience. Two sets of NPE data were combined for use in this study. One was obtained from the NPE Automated Retrieval System (NPEars), and the second was a data base compiled for previous flood risk assessments performed by Pickard, Lowe and Garrick, Inc. (PLG) (References 2-2 and 2-3). The resulting data base for this study is believed to include all major U.S. nuclear power plant floods reported through September 1987.

The data bases and data screening criteria that were used for this study are both discussed in the sections below.

2.1 DATA ACQUISITION

The initial NPEars search was performed using the NPEars menu for the "effects" of reported events and selecting the "flooding" keyword. This search strategy yielded 224 items of which 95 were for boiling water reactors (BWR) and 124 applied to pressurized water reactors (PWR). The PLG data base contained a total of 151 entries that had been obtained from NPE, using the "flooding" and "flooded area" keywords through July 1981.

A comparison of these two data bases revealed 56 items that were common to both, 168 that were unique to the NPEars search, and 89 that were unique to the PLG data base, for a total of 313. However, some of these items did not reflect actual floods. For example, flooding of the main steam lines caused by overfilling a BWR pressure vessel or a PWR steam generator might have appeared in the NPE data base, but would not have been applicable to this study. Similarly, some NPE entries simply provide additional detail on an event that was described in a previous listing and do not actually constitute a new and unique event. Once these items were eliminated from the data base roughly 230 actual flood events remained.

The reports of these events typically included information about the cause of the flood, the components that were affected, and the plant and operator response. However, because of variations in reporting practices among different utilities, the event reports varied significantly in their level of detail. In particular, some reports were only a few lines long, while others (especially for severe events) covered many pages. These reports were then reviewed to permit the categorization of floods by location, size, and mode of plant operation (i.e., shutdown, operation, or both).

2.2 DATA SCREENING CRITERIA

After the flood descriptions retrieved from NPE were reviewed, the data base was screened to remove all items except for water or steam leaks from a piping system to one or more plant buildings or to a site location occupied by permanent plant equipment. Examples of the types of events that would have been excluded, based on the above criteria, are: containment isolation valves that failed local leak rate tests; intra-or inter-system leaks that did not fail all pressure boundaries (so that the water was still contained within a closed system); accumulations of water caused by condensation of atmospheric humidity (unless caused by a steam leak in close proximity to the affected equipment); and floods caused by sources external to the plant, such as heavy rains or excessive groundwater. Applying the above criteria to the event descriptions obtained from NPE yielded a total of 179 events that were input to dBASE III and were considered to be internally generated floods for the purposes of this study.

Finally, the events remaining in the data base after the above screening process were categorized according to their location. A total of 66 floods were identified that affected one of the four critical locations considered in this study; these are described in the next section.

2.3 REFERENCES

2-1. S. M. Stoller Corporation, *Nuclear Power Experience*, Boulder, Colorado.

2-2. Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment," prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983.

2-3. Pickard, Lowe and Garrick, Inc., "Three Mile Island Unit 1 Probabilistic Risk Assessment," prepared for GPU Nuclear Corporation, PLG-0525, November 1987.

3. FLOOD DATA BASE

The data base used in this study was developed as described in Section 2. A total of 66 events, covering the period through September 1987, were judged to be relevant to this study and were therefore included in the flood data base.

The events in the data base were then grouped according to size, location, and the operational mode or modes in which they could have occurred:

1. During shutdown only.
2. During either shutdown or operation.
3. During operation only.

(Floods occurring during construction were placed in either category 1 or category 2, depending on whether they could have occurred at an operating plant.) Finally, summary statistics for each category were obtained using dBASE III, a microcomputer data base management program.

Section 3.1 describes the structure of the dBASE files used in this analysis, and Section 3.2 describes the criteria used to categorize the reported flood events.

3.1 DATA BASE STRUCTURE

The flood data base is contained in two dBASE III files, PLNTDESC.DBF and FLOOD.DBF. The first file contains general plant descriptive information, based on information from the NRC "Gray Books" (Reference 3-1). In particular, the "Gray Books" were used as the source for such information as initial criticality, commercial operation dates, and, also, for cumulative service or availability factors (used to determine the fraction of time, ϕ_{sd}, during which each plant was in shutdown). The specific data fields included in the plant description data file are described in Appendix A.

The second file, FLOOD.DBF, contains data on all of the floods that were identified from *Nuclear Power Experience* (Reference 3-2). This file includes information on the specific plant and unit (or units) affected by each flood; the date and time of the flood; and its location, size, cause, and source. The specific data fields in this file are described in detail in Appendix B.

3.2 DEFINITIONS OF FLOOD CATEGORIES

The data base used in this study was obtained by screening the raw data base from NPEars to eliminate irrelevant or inapplicable events. The remaining 66 events were then categorized according to size, location, and whether they could have occurred during plant operation, shutdown, or both. These three categories were defined as follows:

1. **Shutdown Only.** This category included those floods that occurred during maintenance outages, refueling outages, and cold shutdown if it was judged that the flood could only have occurred during shutdown conditions.

2. **Operating or Shutdown**. This category included events that occurred during shutdown conditions but could have occurred during operation and, also, events that occurred during operation but could just as easily have occurred during shutdown.

3. **Operation Only**. This category included the remainder of the events in the data base, those floods that could only have occurred under conditions unique to hot shutdown or normal power operation; e.g., floods from pipes that would only have water in them under normal operating conditions.

Flood sizes were defined as follows. Small floods were taken to be those with a spill rate on the order of 100 gpm. Medium floods involved spill rates of about 1,000 gpm, while large floods had spill rates of approximately 10,000 gpm. Finally, two events in the data base were categorized as extra large because they involved flow rates on the order of 50,000 gpm.

Four "location" categories were included in this study: the auxiliary building, the turbine building, the circulating water system, and the service water system. The auxiliary building and turbine building were considered as actual flood locations, while the circulating water and service water systems are possible flood sources. These four locations are likely to dominate the plant risk from floods for the reasons discussed in Section 1. The number of floods included in the data base for each location, and their sizes and modes of operation, are shown in Figure 3-1. The remainder of this section defines the four locations and describes the types of floods that occurred in each one.

3.2.1 Auxiliary Building

The term "auxiliary building" was taken to include both the control and the auxiliary buildings although, of course, the actual names of these buildings can vary from one plant to another. For example, at boiling water reactors (BWR), the reactor building is also included in this definition.

The auxiliary buildings of nuclear power plants typically house the components of such systems as the emergency core cooling, residual heat removal (RHR), safety injection, high pressure coolant injection (HPCI), and chemical and volume control (CVCS) systems and the radwaste processing systems, fire protection systems, and standby gas treatment systems. Therefore, there are numerous potential flood locations in the auxiliary building, including:

- Radwaste Area
- Reactor Annulus
- Reactor Building (for BWRs)
- Pump Rooms

Figure 3-1 shows that the vast majority of auxiliary building floods could have occurred during either shutdown or plant operation. Those floods that were judged to be applicable only during operation involved such factors as leakage from the reactor coolant system makeup pumps; typically, these pumps would only be used when the reactor was in operation or hot standby. Floods that were judged to be possible only during shutdown involved such activities as hydrostatic testing or maintenance that requires components to be isolated from their normal configurations.

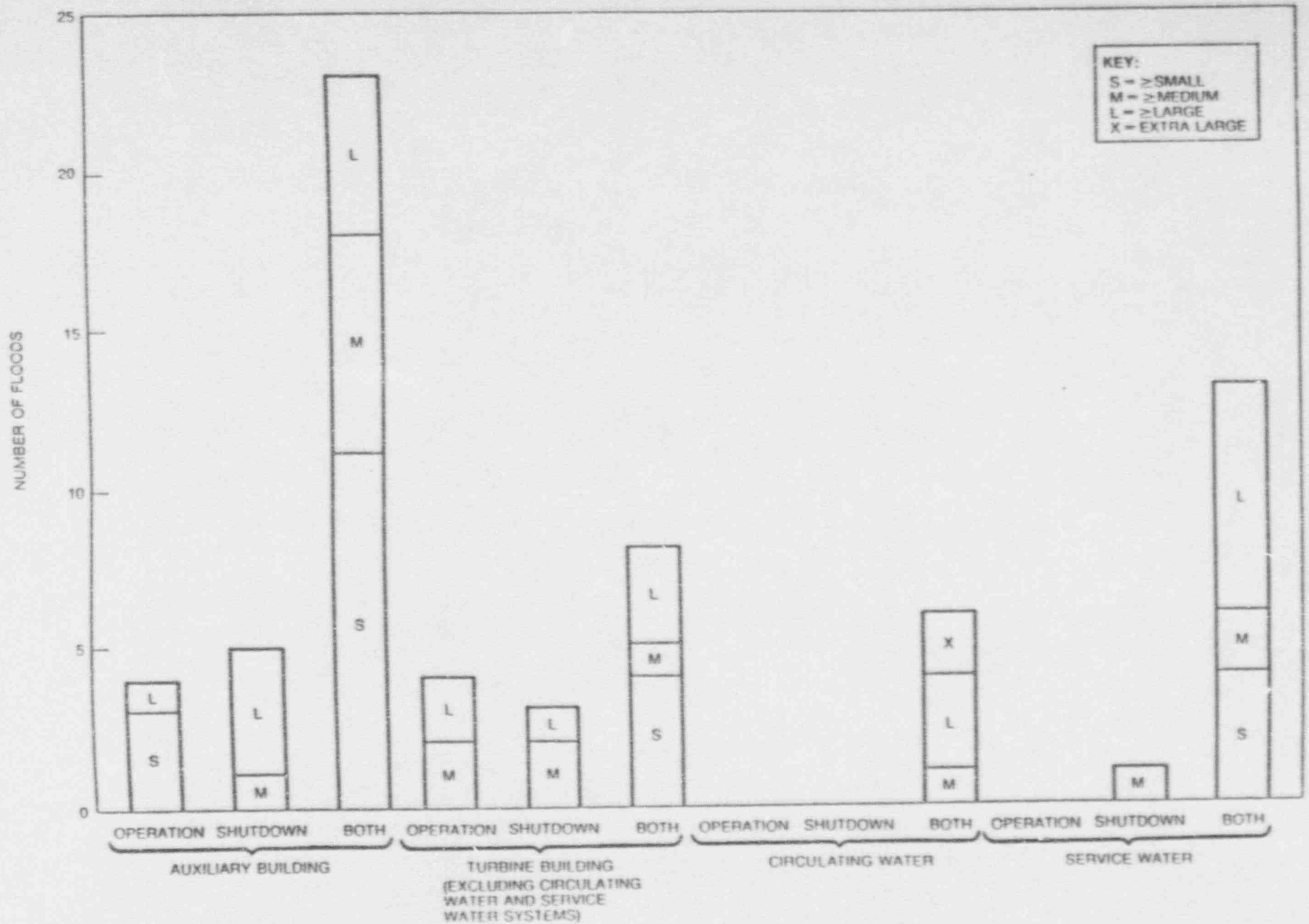


Figure 3-1. Number of Floods by Operational Mode and Flood Size

3.2.2 Turbine Building

The term "turbine building" was taken to include both the turbine building per se and the boiler room if one is present. However, few nuclear power plants have nonnuclear auxiliary boilers, so this category of possible flood sources was not very important. Typical flood sources in the turbine building included: main feedwater valves and suction lines, the condensate storage tank and booster pumps, the condenser water boxes, etc.

Of course, circulating water and service water systems are very important flood sources for a turbine building. Because of sharp plant-to-plant variability in terms of the location of different circulating water and service water components, two frequencies are provided for turbine building floods in this study. In one set of frequencies, the contribution of circulating water and service water systems are excluded, and the second set includes their contribution.

As shown in Figure 3-1 for events excluding the circulating water and service water systems, roughly half the turbine building floods could have occurred during either shutdown or plant operation. Those floods that were judged to be applicable only during operation involved the main feedwater system, which would typically be in operation only when a plant was at power. Those floods that were judged to be possible only during shutdown typically involved either major plant modifications or maintenance activities, such as cleaning of the condenser water boxes.

3.2.3 Circulating Water System

The circulating water floods that were observed involved such factors as valve or pump leaks, failures of expansion joints, and so on. Problems such as these allowed circulating water to flow into plant buildings, resulting in flooding such areas as the turbine building, the circulating water pump house and discharge structure, the condensate pump room, the main condenser pit, and so on. As can be seen from this brief discussion, the areas that can be affected by circulating water floods are quite diverse since this system supplies many areas of a nuclear power plant.

As shown in Figure 3-1, all of the observed circulating water floods could have happened either during operation or during plant shutdown. However, there were relatively few circulating water floods in the data base (only six in total), so this does not imply that shutdown-only or operation-only floods could not have occurred.

3.2.4 Service Water System

The observed service water floods in the data base involved a wide variety of causes, including such factors as valve leaks or ruptures, gasket ruptures, line leaks, coupling failures, and pump seal leaks. The floods resulting from these events affected such areas as pump rooms, valve pits, the service water intake structure, and areas of the reactor building and the turbine building.

Figure 3-1 shows that the vast majority of service water floods could have occurred either during operation or during plant shutdown. One shutdown-only flood was observed, which was associated with maintenance on a service water valve; no operation-only events were found in the data base.

3.3 REFERENCES

3-1. U. S. Nuclear Regulatory Commission, "Licensed Operating Reactors: Summary Status Report," NUREG-0020.

3-^. S. M. Stoller Corporation, *Nuclear Power Experience*, Boulder, Colorado.

4. FLOOD FREQUENCY ANALYSIS

4.1 FREQUENCIES FOR SHUTDOWN AND OPERATION

The frequency of floods during shutdown at a given location in a plant is quantified (as described in Section 1) according to the equation,

$$\lambda_i = \lambda_{i,sd} + \lambda_{i,sd/op} \tag{4.1}$$

where

$\lambda_{i,sd}$ = the frequency of floods in location i that can occur only during shutdown.

$\lambda_{i,sd/op}$ = the frequency of floods in location i that can occur during either shutdown or operation.

and λ_i is in units of floods per year of plant shutdown.

(Note that the shutdown term in the above equation can include construction floods that could have occurred either during a normal shutdown or during an extended outage involving large-scale plant modifications. The shutdown/operation term includes floods that occurred during construction and preoperational testing if they could also have occurred during periods of normal plant operation.)

An approach similar to that of Equation (4.1) is used to estimate the flood frequency during periods of plant operation:

$$\lambda_i^* = \lambda_{i,sd/op} + \lambda_{i,op} \tag{4.2}$$

where

$\lambda_{i,op}$ = the frequency of floods in location i that can occur only during operation.

Note that λ_i^* is in units of floods per year of plant operation.

It should be cautioned that these results are given in terms of the frequency of floods for a full year of plant operation or shutdown. If one desires to obtain the total frequency of floods during a year involving a fraction dsd of shutdown time and $1-\phi_{sd}$ of operation time, the results of Equations (4.1) and (4.2) must be combined using a weighted average, as described in Section 1:

$$\Lambda_{i,T} = \lambda_i^*(1-\phi_{sd}) + \lambda_i\phi_{sd} \tag{4.3}$$

where the units of $\Lambda_{i,T}$ (the total flood frequency) are floods per calendar year. Finally, the fraction of this total that occurs during shutdown (i.e., the frequency of shutdown floods during a typical calendar year) would be given by the second term of Equation (4.3),

$$\Lambda_i = \lambda_i\phi_{sd} = (\lambda_{i,sd/op} + \lambda_{i,sd})\phi_{sd} \tag{4.4}$$

while the fraction of floods occurring during operation would be given by the first term,

$$\Lambda_i^* = \lambda_i^*(1 - \phi_{sd}) = (\lambda_{i,sd/op})\phi_{sd} \quad (4.5)$$

In Equations (4.4) and (4.5), the units of Λ_i are floods occurring during shutdown in a typical calendar year, and Λ_i^* is in units of floods during operation in a typical calendar year, where a year is assumed to include a fraction, ϕ_{sd}, of shutdown time.

Section 4.1 below describes the Bayesian estimation procedure used in this study to develop probability distributions for the input quantities $\lambda_{i,sd}$, $\lambda_{i,op}$, and $\lambda_{i,sd/op}$ needed as input to Equations (4.1) and (4.2), and Section 4.2 expands on the treatment of construction floods in particular. The results of this analysis are presented in Section 5.

4.2 BUILDING-SPECIFIC FREQUENCY EVALUATION

To establish the flood frequencies for turbine and auxiliary buildings, one should use a combination of the frequencies provided in this report. For example, for a turbine building that includes service water pumps, heat exchangers and piping, circulating water piping, and expansion joints, one may add to the turbine building flood frequency (the one that excludes circulating water and service water systems) a large fraction of the service water flood frequency and about a quarter of the circulating water flood frequency. For service water, a large fraction is recommended because this turbine building contains most of the flood causing components of the system. For circulating water about a quarter of the frequency is recommended because only the expansion joints and some short legs of the pipes are present in this building.

If the turbine building can be regarded as "average" (i.e., it includes some service water and circulating water piping and components), one may use the frequency that includes service water and circulating water contributions.

4.3 ESTIMATION PROCEDURE

The estimation procedure used in this study is based on the two-stage Bayesian analysis methodology described in Reference 4-1. However, unlike in most applications of this methodology, it was assumed that the frequency of floods varies from site to site, not from unit to unit. This reflects a belief that much of the difference in flood rates can be attributed to plant management and that the differences in management between different plants at the same site should not be too great. Therefore, it was expected that different plants at the same site would have similar flood frequencies.

In the two-stage methodology, the variation in the frequency of floods from one site to another is assumed to be described by a lognormal distribution whose parameters, μ and σ (the median and lognormal standard deviation), are unknown. The purpose of the estimation procedure is to develop a joint probability distribution for μ and σ, given the evidence from the data base. (In particular, for each site, the data base includes information on the total number of floods and the number of years of operating and/or shutdown experience accrued to date.) The distribution over μ and σ obtained in this way is then used to weight the various lognormal distributions corresponding to different combinations of μ and σ, to derive an average generic distribution for the event frequency in question. The BEST4 code (Reference 4-2) was used to perform the actual computations.

It should be pointed out here that the accuracy of the data base used in this study could be affected by bias in the reporting of floods. In particular, some floods may not be reported in NPE. From a risk standpoint, however, the potential bias introduced by the underreporting of floods is not likely to be very large. Unreported floods, by their very nature, are likely not to be very severe. Therefore, no adjustments were made to the data used in the estimation process to account for possible biases in event reporting.

4.4 TREATMENT OF FLOODS OCCURRING DURING CONSTRUCTION

The data base retrieved from NPE for use in this study contained several floods that occurred during construction or preoperational testing, and a few of these were judged to be applicable to this analysis. Because only a few events were judged to be applicable, they were included in the analyses of $\lambda_{i,sd}$, $\lambda_{i,sd/op}$, and $\lambda_{i,op}$, rather than in a separate analysis for the frequency of floods during construction.

To rigorously account for construction floods in the estimation process, one would in theory need data on not only the total number of floods occurring during construction, but also the relevant exposure time over which they were observed. Thus, one would need to determine how long each plant was in a construction configuration similar to one of the configurations that might be encountered during normal shutdown or operation.

In general, the plant configurations found during construction do not approach those found during operation and shutdown until the very last stages of construction and testing. Therefore, the relevant exposure times during construction are likely to be short; e.g., on the order of only 1 to 3 years per plant. Because of this, a simple but slightly conservative approach was adopted. In particular, construction-related floods were added to the data base, but no additional exposure time was added to the totals assumed in the analyses of $\lambda_{i,sd}$, $\lambda_{i,sd/op}$, and $\lambda_{i,op}$.

Another possible conservatism regarding the treatment of construction floods is that their frequency may not be directly comparable to flood frequencies after commercial operation. In particular, many types of conditions that could result in construction floods (e.g., large openings in equipment that would normally be sealed off; pipelines that are uncapped and are not connected to mating equipment) are unlikely to occur after commercial operation, so the frequency of construction floods might be higher than the corresponding frequencies during periods of normal plant operation and shutdown.

4.5 REFERENCES

4-1. Kaplan, S., "On a "Two-Stage" Bayesian Procedure for Determining Failure Rates from Experiential Data," IEEE *Transactions on Power Apparatus and Systems*, Vol. PAS-102, No. 1, January 1983.

4-2. Mosleh, A., and D. B. Simpson, "Bayesian Estimation Computer Code 4 (BEST4) Users Manual," Pickard, Lowe and Garrick, Inc., PLG-0460, December 1985.

5. RESULTS

5.1 AUXILIARY BUILDING FLOOD FREQUENCY

Figure 3-1 shows that the data base for auxiliary building floods included 4 floods that could have occurred only during operation, 5 that could have occurred only during shutdown (including 1 that affected both the auxiliary building and the turbine building), and 23 that could have occurred during either operation or shutdown.

The prior distribution used in the analysis of auxiliary building floods encompassed possible median flood frequencies from 1×10^{-4} per year to nearly 0.5 per year and range factors from less than 2 to more than 40. These ranges are broad enough to allow a wide range of possible flood frequencies. The same set of median values and range factors was used for each type of flood (i.e., shutdown-only, operation-only, and both), and also for each size category. (In this table, "≥ small" includes all floods, "≥ medium" includes floods of at least medium size, and "≥ large" includes only large or extra-large floods. Use of the same medians and range factors for all distributions avoided the introduction of analyst bias about which types of floods are the most likely.

Using the above prior distribution with the two-stage Bayesian methodology discussed in Section 4, probability distributions were derived for the frequencies of floods occurring during shutdown only, during operation only, and during both shutdown and operation. The main characteristics (i.e., the 5th, 50th, and 95th percentiles and the mean value) of these distributions for each size category are summarized in Table 5-1.

Summing the relevant distributions from Table 5-1 gives total auxiliary building flood frequencies for shutdown (shutdown-only plus shutdown/operation) and for operation (operation-only plus shutdown/operation). These results are summarized in Table 5-2 and shown graphically in Figure 1-1. As can be seen from that figure, the frequency of floods during shutdown tends to be slightly higher than that during operation, and large floods are somewhat less likely than small floods. However, the distributions for all the flood frequencies shown in Figure 1-1 are very broad, with a substantial amount of overlap. In addition, the overall frequency of floods is dominated by floods that could have occurred either during operation or during shutdown (as can be seen from Figure 3-1), so the increment associated with shutdown-only floods is not very large.

5.2 TURBINE BUILDING FLOOD FREQUENCY

Figure 3-1 shows that there were four turbine building floods (excluding circulating water and service water systems) applicable to operation only, three applicable to shutdown only (including one that also affected the auxiliary building), and eight that could have occurred during either operation or shutdown. The prior distribution used in the analysis of turbine building floods was the same as that for auxiliary building floods to avoid the introduction of bias about which types of floods are the most frequent. Using this prior with the two-stage Bayesian methodology discussed earlier, distributions were derived for the frequencies of turbine building floods occurring during shutdown only, during operation only, and during

Table 5-1 (Page 1 of 3). Main Characteristics of Flood Frequency Distributions

System	Operation Only ($\lambda_{i,\ op}$)	Shutdown Only ($\lambda_{i,\ sd}$)	Operation or Shutdown ($\lambda_{i,\ sd/op}$)	5th Percentile	Median	95th Percentile	Mean
Auxiliary Building	≥ Small			1.33E-04	2.12E-03	1.89E 02	6.70E-03
	≥ Medium			2.51E-05	4.42E-04	5.54E-03	1.80E-03
	≥ Large			2.51E-05	4.42E-04	5.54E-03	1.80E-03
		≥ Small		2.39E-04	5.16E-03	4.84E-02	1.70E-02
		≥ Medium		2.39E-04	5.16E-03	4.84E-02	1.70E-02
		≥ Large		2.49E-04	4.62E-03	3.76E-02	1.33E-02
			≥ Small	2.62E-03	1.27E-02	5.14E-02	2.32E-02
			≥ Medium	6.65E-04	5.75E-03	3.13E-02	1.28E-02
			≥ Large	9.14E-05	1.65E-03	1.67E-02	5.52E-03
Turbine Building (excluding circulating water and service water systems)	≥ Small			1.36E-04	2.12E-03	1.84E-02	6.38E-03
	≥ Medium			1.36E-04	2.12E-03	1.84E-02	6.38E-03
	≥ Large			4.71E-05	8.99E-04	9.45E-03	3.17E-03
		≥ Small		1.92E-04	3.15E-03	2.85E-02	9.83E-03
		≥ Medium		1.92E-04	3.15E-03	2.85E-02	9.83E-03
		≥ Large		3.81E-05	8.04E-04	1.10E-02	3.41E-03
			≥ Small	1.51E-04	2.61E-03	2.60E-02	8.63E-03
			≥ Medium	1.56E-04	1.93E-03	1.36E-02	5.07E-03
			≥ Large	1.02E-04	1.47E-03	1.14E-02	4.10E-03

Note: Exponential notation is indicated in abbreviated form; e.g., 1.33E-04 = 1.33×10^{-04}.

Table 5-1 (Page 2 of 3). Main Characteristics of Flood Frequency Distributions							
System	**Operation Only ($\lambda_{i, op}$)**	**Shutdown Only ($\lambda_{i, sd}$)**	**Operation or Shutdown ($\lambda_{i, sd/op}$)**	**5th Percentile**	**Median**	**95th Percentile**	**Mean**
Turbine Building (including service water and circulating water systems)	≥ Small ≥ Medium ≥ Large ≥ Extra Large			1.36E-04 1.36E-04 4.71E-05 1.32E-05	2.12E-03 2.12E-03 8.99E-04 1.95E-04	1.84E-02 1.84E-02 9.45E-03 2.57E-03	6.38E-03 6.38E-03 3.17E-03 8.61E-04
		≥ Small ≥ Medium ≥ Large ≥ Extra Large		1.92E-04 1.92E-04 3.81E-05 1.72E-05	3.15E-03 3.15E-03 8.04E-04 2.66E-04	2.85E-02 2.85E-02 1.10E-02 4.31E-03	9.15E-03 9.15E-03 3.41E-03 1.37E-03
			≥ Small ≥ Medium ≥ Large ≥ Extra Large	2.92E-04 2.34E-04 2.08E-04 1.64E-05	4.76E-03 3.32E-03 2.48E-03 3.23E-04	4.84E-02 2.04E-02 1.72E-02 3.94E-03	1.58E-02 9.22E-03 6.27E-03 1.32E-03
Note: Exponential notation is indicated in abbreviated form; e.g., 1.33E-04 = 1.33×10^{-04}.							

Table 5-1 (Page 3 of 3). Main Characteristics of Flood Frequency Distributions

System	Operation Only ($\lambda_{i, op}$)	Shutdown Only ($\lambda_{i, sd}$)	Operation or Shutdown ($\lambda_{i, sd/op}$)	5th Percentile	Median	95th Percentile	Mean
Circulating Water	≥ Small			1.53E-05	1.95E-04	2.57E-03	8.44E-04
	≥ Medium			1.53E-05	1.95E-04	2.57E-03	8.44E-04
	≥ Large			1.53E-05	1.95E-04	2.57E-03	8.44E-04
		≥ Small		1.91E-05	2.66E-04	4.31E-03	1.37E-03
		≥ Medium		1.91E-05	2.66E-04	4.31E-03	1.37E-03
		≥ Large		1.91E-05	2.66E-04	4.31E-03	1.37E-03
			≥ Small	1.90E-04	2.45E-03	1.80E-02	6.30E-03
			≥ Medium	1.90E-04	2.45E-03	1.80E-02	6.30E-03
			≥ Large	1.34E-04	1.91E-03	1.58E-02	5.37E-03
			Extra Large	3.49E-05	6.30E-04	6.64E-03	2.21E-03
Service Water	≥ Small			1.53E-05	1.95E-04	2.57E-03	8.44E-04
	≥ Medium			1.53E-05	1.95E-04	2.57E-03	8.44E-04
	≥ Large			1.53E-05	1.95E-04	2.57E-03	8.44E-04
		≥ Small		3.64E-05	8.19E-04	1.12E-02	3.57E-03
		≥ Medium		3.64E-05	8.19E-04	1.12E-02	3.57E-03
		≥ Large		1.90E-05	2.49E-04	4.31E-03	1.39E-03
			≥ Small	3.03E-04	4.50E-03	3.86E-02	1.26E-02
			≥ Medium	1.40E-04	2.60E-03	2.92E-02	9.23E-03
			≥ Large	1.97E-04	2.68E-03	1.92E-02	7.02E-03

Note: Exponential notation is indicated in abbreviated form; e.g., 1.33E-04 = 1.33×10^{-04}.

Table 5-2 (Page 1 of 2). Main Characteristics of Total Flood Frequency Distributions						
System	Total Operation ($\lambda_{i,\,op} + \lambda_{i,\,sd/op}$)	Total Shutdown ($\lambda_{i,\,sd} + \lambda_{i,\,sd/op}$)	5th Percentile	Median	95th Percentile	Mean
Auxiliary Building	≥ Small		5.41E-03	2.11E-02	8.03E-02	3.05E-02
	≥ Medium		1.43E-03	8.54E-03	4.90E-02	1.50E-02
	≥ Large		4.47E-04	3.38E-03	2.40E-02	7.52E-03
		≥ Small	6.82E-03	2.68E-02	1.05E-01	4.03E-02
		≥ Medium	3.46E-03	1.70E-02	9.07E-02	2.98E-02
		≥ Large	1.45E-03	9.69E-03	5.56E-02	1.89E-02
Turbine Building (excluding circulating water and service water systems)	≥ Small		1.22E-03	7.84E-03	4.98E-02	1.47E-02
	≥ Medium		1.17E-03	6.16E-03	3.30E-02	1.12E-02
	≥ Large		6.19E-04	3.85E-03	2.11E-02	7.14E-03
		≥ Small	1.51E-03	9.81E-03	5.57E-02	1.88E-02
		≥ Medium	1.40E-03	8.30E-03	5.22E-02	1.53E-02
		≥ Large	5.80E-04	3.93E-03	2.29E-02	7.60E-03
Turbine Building (including circulating water and service water systems)	≥ Small		1.74E-03	1.13E-02	8.62E-02	2.23E-02
	≥ Medium		1.48E-03	8.81E-03	5.28E-02	1.58E-02
	≥ Large		9.1E-04	5.3E-03	2.9E-02	9.62E-03
	≥ Extra Large		1.4E-04	9.3E-04	8.0E-03	2.25E-03
		≥ Small	2.10E-03	1.36E-02	8.11E-02	2.49E-02
		≥ Medium	1.84E-03	1.06E-02	5.45E-02	1.84E-02
		≥ Large	8.7E-04	5.3E-03	3.1E-02	9.66E-03
		≥ Extra Large	1.5E-04	1.2E-03	8.4E-03	2.66E-03
Note: Exponential notation is indicated in abbreviated form; e.g., 5.41E-03 = 5.41×10^{-03}.						

Table 5-2 (Page 2 of 2). Main Characteristics of Total Flood Frequency Distributions						
System	**Total Operation** ($\lambda_{I,\ op} + \lambda_{i,\ sd/op}$)	**Total Shutdown** ($\lambda_{i,\ sd} + \lambda_{i,\ sd/op}$)	**5th Percentile**	**Median**	**95th Percentile**	**Mean**
Circulating Water	≥ Small		4.98E-04	3.49E-03	2.32E-02	7.17E-03
	≥ Medium		4.98E-04	3.49E-03	2.32E-02	7.17E-03
	≥ Large		3.79E-04	3.15E-03	2.30E-02	6.24E-03
	Extra Large		1.92E-04	1.35E-03	9.63E-03	3.05E-03
		≥ Small	5.35E-04	3.95E-03	2.30E-02	7.57E-03
		≥ Medium	5.35E-04	3.95E-03	2.30E-02	7.57E-03
		≥ Large	4.32E-04	3.28E-03	2.09E-02	6.64E-03
		Extra Large	2.21E-04	1.57E-03	1.12E-02	3.46E-03
Service Water	≥ Small		7.67E-04	6.79E-03	4.85E-02	1.36E-02
	≥ Medium		3.96E-04	3.91E-03	4.53E-02	1.02E-02
	≥ Large		5.20E-04	3.92E-03	2.94E-02	7.88E-03
		≥ Small	1.08E-03	8.36E-03	5.13E-02	1.64E-02
		≥ Medium	7.27E-04	5.93E-03	4.73E-02	1.29E-02
		≥ Large	5.75E-04	4.69E-03	2.93E-02	8.44E-03

Note: Exponential notation is indicated in abbreviated form; e.g., 4.98E-04 = 4.98×10^{-04}.

both shutdown and operation. The main characteristics of the resulting distributions for each size category are shown in Table 5-1.

Summing the relevant distributions from Table 5-1 gives total turbine building flood frequencies for shutdown (shutdown-only plus shutdown/operation) and also for operation (operation-only plus shutdown/operation). These are summarized in Table 5-2 and are shown graphically in Figure 1-2. Based on these results, large floods are somewhat less likely to occur than small floods. However, there appears to be very little difference between the frequencies of floods during shutdown and during operation. This is because the frequencies for shutdown-only and operation-only floods are quite similar (as shown in Table 5-1) and, in any case, are dominated by the frequency of floods that could have occurred at either time.

5.3 CIRCULATING WATER SYSTEM FLOOD FREQUENCY

As shown in Figure 3-1, no circulating water floods were judged to be applicable only during operation or only during shutdown; six were judged to be potentially applicable during either operation or shutdown. The prior distribution used for circulating water system floods was the same as that for auxiliary building floods. Using this prior distribution with the two-stage Bayesian methodology, the distributions shown in Table 5-1 were derived for the frequencies of circulating water floods occurring during shutdown only, during operation only, and during either shutdown or operation. As shown in that table, the frequency of operation-only floods is almost the same as that of shutdown-only floods. This is because the distributions for these frequencies were not based on any observed floods. Therefore, there was little reason to expect the frequency of shutdown-only floods to be significantly different from the frequency of operation-only floods. The only factor tending to result in a lower flood frequency during periods of operation is the larger amount of flood-free experience accrued to date.

Summing the relevant distributions from Table 5-1 gives total circulating water system flood frequencies for shutdown (shutdown-only plus shutdown/operation), and for operation (operation-only plus shutdown/operation), as shown in Table 5-2 and Figure 1-3. Figure 1-3 shows that the frequency of circulating water floods during shutdown is virtually equal to the frequency during periods of plant operation, the total frequency is dominated by events that could have occurred during either operation or shutdown. In addition, based on the results in Figure 1-3, there is no apparent difference between the frequency of all floods and the frequency of at least medium-sized floods. However, this is caused by the lack of small circulating water floods in the data base. The results shown in Figure 1-3 should not be taken to imply that there is no difference in frequency between all circulating water floods and those of at least medium size.

5.4 SERVICE WATER SYSTEM FLOOD FREQUENCY

Figure 3-1 shows that there were 13 service water floods that could have occurred during either operation or shutdown and 1 in the shutdown-only category. No operation-only service water floods were observed. The prior used for service water system floods was the same as that for the other three flood locations. Using this prior distribution, the distributions shown in Table 5-1 were derived for the frequencies of service water floods occurring during shutdown only, during operation only, and during both shutdown and operation. As shown in that table, the frequency of shutdown-only floods appears to be slightly higher than the frequency of floods that can only occur during periods of operation. However, the distributions for these frequencies were based on only one shutdown flood and no operation-only floods. The uncertainty about these frequencies is therefore quite broad, and additional information could well have led to substantially different results.

Sun ing the distributions from Table 5-1 gives total service water system flood frequencies for shutdown and operation as summarized in Table 5-2 and shown in Figure 1-4. Based on these results, the frequency of service water floods during shutdown is only slightly higher than the frequency during plant operation. The vast majority of service water floods in the data base could have occurred during either operation or shutdown.

5.5 CONCLUSIONS

Figure 5-1 shows the mean frequencies of all sizes of floods for the four locations analyzed in this study: the auxiliary building, the turbine building, the circulating water system, and the service water system. Based on these results, the circulating water system seems to be the least likely to cause floods with mean frequencies less than 10^{-2} per year even for small floods. The frequencies of floods in the auxiliary building and the turbine building and floods caused by the service water system are all roughly comparable; however, the auxiliary building does have a somewhat higher frequency for small floods in particular.

For most of the locations and flood sizes analyzed here, the flood frequency appears to be nearly the same regardless of whether the plant is in operation or in shutdown. In particular, for the circulating water system, virtually no difference in frequency was observed (only about 6%). For the turbine building and the service water system, the frequency of floods during shutdown is slightly higher than during normal operation, but only by about 20% to 40%, and the difference diminishes for large floods.

Only for the auxiliary building was the flood frequency during shutdown consistently larger than during operation; in fact, for medium-sized or larger auxiliary building floods, the difference is actually a factor of 2 or more. It is unclear whether this reflects a larger number of shutdown activities that can cause floods in the auxiliary building than in other areas of the plant or whether there were simply more data available to estimate the frequency of auxiliary building floods. However, the evidence in Figure 3-1 shows that the number of shutdown-only auxiliary building floods was actually greater than the number of operation-only floods, even though the total shutdown time accrued to date was less than half of the total operation time. This suggests that the observed increase in the frequency of auxiliary building floods during plant shutdown is probably accurate.

Another interesting result of this analysis is that the difference in mean frequency between the largest and the smallest floods in any given location was not very large--a factor of less than 2 for the service water system and 2 to 2.5 for most other locations, reaching a maximum of 4 for auxiliary building floods during periods of plant operation. At first, this might seem counter-intuitive; most people would probably expect at least an order of magnitude difference in frequency between the smallest and largest floods in a given location. In evaluating these results, however, it should be borne in mind that small floods are the most likely to be underreported, so the difference may be greater than is indicated by

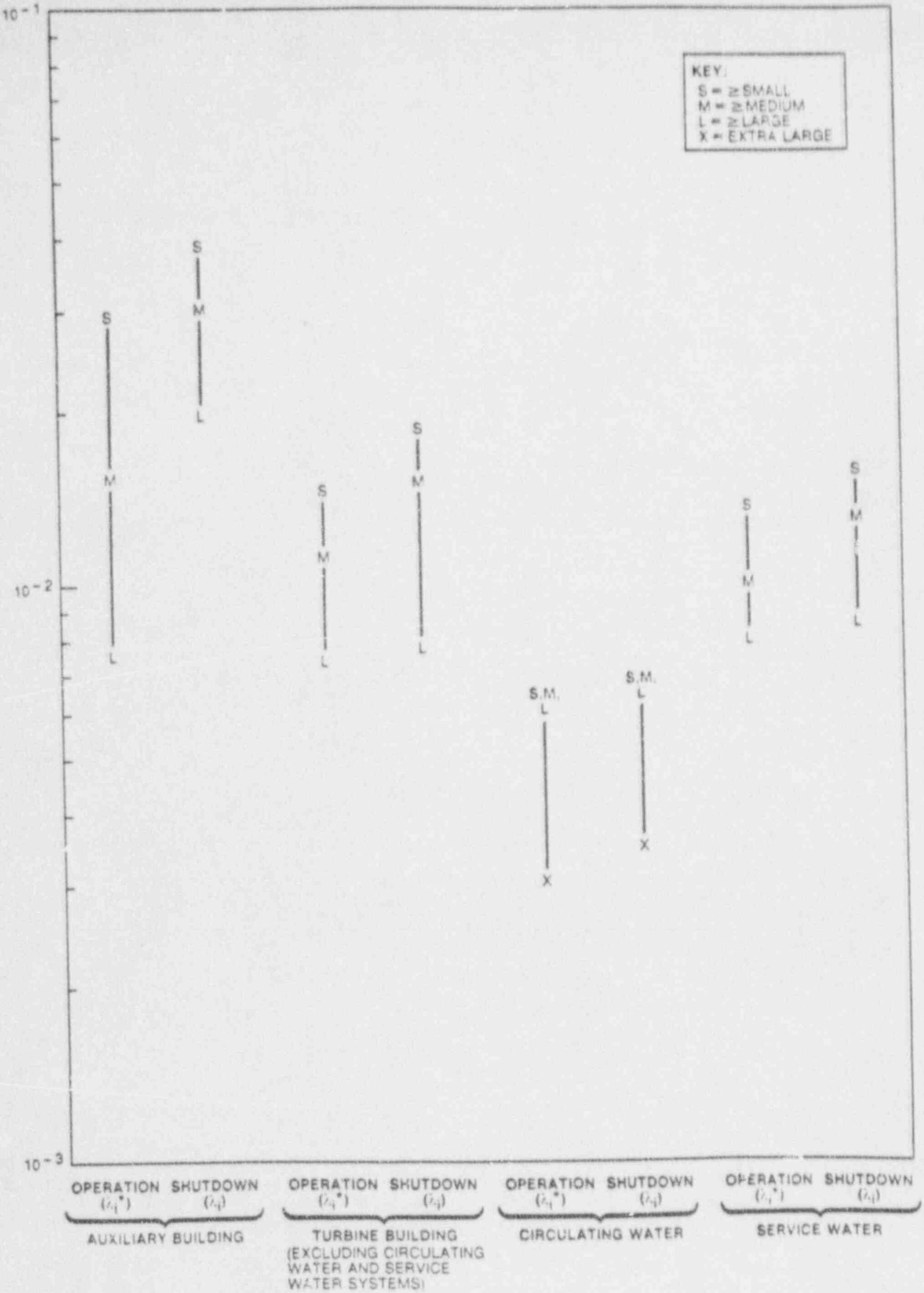


Figure 5-1. Me_n Flood Frequencies

the results in Table 5-2. The results of this study do not support the conjecture that large floods are in general much less likely than small ones.

APPENDIX A. STRUCTURE OF THE PLANT DESCRIPTIVE DATA BASE FILE

The data base file PLNTDESC.DBF contains general descriptive information about nearly all BWR and PWR nuclear power plants in the United States. The structure of that file is presented in the following two tables. Table A-1 shows the various fields contained in the file, and Table A-2 describes the type of information stored in each field.

Most of the data contained in the file were obtained from several fire data base files developed by Sandia National Laboratories (Reference A-1). However, some data values have been changed, and service factor (i.e., availability) data have been added. All of the changes and additions were based on the "NRC Gray Books" (Reference A-2).

REFERENCES

A-1. Wheelis, W. T., "User's Guide for a Personal-Computer-Based Nuclear Power Plant Fire Data Base," Sandia National Laboratories, NUREG/CR-4586, SAND86-0300, August 1986.

A-2. U.S. Nuclear Regulatory Commission, "Licensed Operating Reactors: Status Summary Report," NUREG-0020, Vol. 2, No. 11, November 1978; Vol. 3, No. 4, April 1979, and Vol. 11, No. 7, July 1987.

Table A-1. Structure of Plant Descriptive Data Base

Field	Field Name*	Type	Width
1	PLANTIDNUM	Character	4
2	PLANT_UNIT	Character	24
3	STATE_TOWN	Character	20
4	CAPACITY	Character	10
5	UNITATSITE	Numeric	1
6	UTILITYPRN	Character	60
7	REACTORTYP	Character	8
8	REACTORSUP	Character	23
9	OL_ISSUED	date	8
10	INIT_CRIT	date	8
11	COMM_OPER	date	8
12	DECOM_DATE	date	8
13	SRVC_FACTR	Numeric	4
14	TEXT1	Character	65
15	TEXT2	Character	65
16	TEXT3	Character	65

Number of Data Records: 140
Date of Last Update: February 12, 1988

*Fields are described in Table A-2.

Table A-2. Field Descriptions for Plant Descriptive Data	
Field	**Description**
1	**PLANTIDNUM**. Each unit of each plant was assigned an arbitrary plant identification number. These numbers were initially assigned sequentially in the same alpha-numeric order as the unit-numbered plants.
2	**PLANT_UNIT**. This identifies each entry by the official plant name and its unit number (if any).
3	**STATE_TOWN**. This specifies the location of the plant, by state and the nearest town or city.
4	**CAPACITY**. This gives the net MWe power output of the plant.
5	**UNITATSITE**. This specifies the total number of units that are located at the site.
6	**UTILITYPRN**. This identifies the principal utility that operates the plant/unit.
7	**REACTORTYP**. This indicates what the reactor type is: PWR, BWR, LWBR, or HTGR
8	**REACTORSUP**. This identifies the reactor supplier.
9	**OL_ISSUED**. This indicates the date on which NRC granted the operating license.
10	**INIT_CRIT**. This indicates the date on which initial criticality officially occurred.
11	**COMM_OPER**. This indicates the date on which NRC granted the license to begin commercial operation.
12	**DECOM_DATE**. This marks the date on which the plant was officially decommissioned.
13	**SRVC_FACTR**. This is the cumulative service factor, which is the total operating time divided by the total time since the beginning of commercial operation.
14	**TEXT1**. This is the first of three fields provided for comments about an individual plant or about the plants as a whole. These fields were used to identify data sources used other than the NPE data.
15	**TEXT2**. This is the second of the three comment fields.
16	**TEXT3**. This is the last of the three comment fields.

APPENDIX B. STRUCTURE OF THE FLOOD DATA BASE FILE

All of the flood data were collected into a single file named FLOOD.DBF, which was created via dBASE III. The data were obtained from *Nuclear Power Experience* (NPE). The structure of the file is described in Table B-1 and Table B-2. Table B-1 shows the various fields contained in the file, and Table B-2 describes the type of information stored in each field. Finally, Table B-3 explains the system and subsystem codes used by NPE, which are stored in field 28 (SYSTM_code) of the data base file.

Table B-1. Structure of the Flood Data Base			
Field	Field Name*	Type	Width
1	INCIDNTNUM	Character	4
2	PLANTIDNUM	Character	4
3	TOTUNTAFCT	Numeric	1
4	INCL_EXCL	Character	1
5	FLOOD_DATE	Date	8
6	END_DATE	Date	8
7	STATUS_BEF	Character	40
8	INITL_MODE	Character	1
9	STATUS_AFT	Character	40
10	POWR_REDUC	Character	10
11	OUTAG_TIME	Character	10
12	FLOOD_LOCN	Character	40
13	AUX_BLDG	Character	1
14	CONTAINMNT	Character	1
15	CONTROL_RM	Character	1
16	COOLG_TOWR	Character	1
17	DIESL_BLDG	Character	1
18	EXTERNAL	Character	1
19	PUMP_HOUSE	Character	1
20	RADWASTBLD	Character	1
21	SCREEN_HSE	Character	1
22	TURBN_BLDG	Character	1
23	YARD	Character	1
24	FLOOD_VOL	Numeric	7
25	FLOOD_RATE	Numeric	7
26	FLOOD_TIME	Numeric	5
27	FLOOD_CAUS	Character	40
28	SYSTM_CODE	Numeric	4
29	WATR_SOURC	Character	20
30	SRC_CAPCTY	Numeric	7
31	DETECTMETH	Character	40
32	FLOOD_TERM	Character	40
33	SAFSYSAFCT	Character	40
34	REDSYSAFCT	Character	40
35	FLOOD_BARR	Character	40
36	CORECTACTN	Character	40
37	COMMENTS	Character	40
38	REFERENCES	Character	60

Number of Data Records: 179
Date of Last Update: February 5, 1988

*Fields are described in Table B-2

Table B-2 (Page 1 of 3). Field Descriptions for Plant Descriptive Data	
Field	**Description**
1	**INCIDNTNUM**. Each individual flood included in the data base is assigned a unique incident nur ber. These numbers serve a a quick means of identifying flood incidents.
2	**PLANTIDNUM**. This number identifies the specific plant and unit involvedin a specific flood incident according to the identifying number assigned that particular plant and unit in the plant descriptive file PLNTDESC.DBF.
3	**TOTUNTAFCT**. This indicates the total number of units affected by the flood
4	**INCL_EXCL**. The letter "I" signifies that the incident is to be included in the analysis; the letter "E" signifies that the incident is to be excluded from the analysis.
5	**FLOOD_DATE**. This is the date on which the flood occurred (started).
6	**END_DATE**. This is the date on which the flood ended.
7	**STATUS_BEF**. This identifies the operational status of the plant immediately before the flood--construction, shutdown (hot, cold, or refueling), or running (with power level if indicated in the data source).
8	**INITL_MODE**. This is a single letter that identifies the initial operating status of the plant--an abbreviation of the description given in field 7. The letters have the following meaning: • P--Running at Power • C--Cold Shutdown • H--Hot Shutdown • R--Refueling • I--Initial Construction • S--Startup (very low power) • T--Low Power Physics Testing
9	**STATUS_AFT**. This indicates the status after the flood occurred -- for example, continued power operation, shutdown, etc.
10	**POWR_RDEUC**. This indicates the amount (in MWe) by which the power had to be reduced as a direct consequence of the flood, if known.
11	**OUTAG_TIME**. This is the amount of power operating time (in hours, days, weeks, etc.) lost as a direct consequence of the flood, if known.
12	**FLOOD_LOCN**. This describes the location of the flood.

Table B-2 (Page 2 of 3). Field Descriptions for Plant Descriptive Data	
Field	Description
13	**AUX_BLDG**. If the auxiliary building was flooded, then a single letter is entered in this field to indicate the size of the flood in the building: • S--Small • M--Medium • L--Large • X--Extra Large This same classification scheme applies to fields 14 to 23.
14	**CONTAINMNT**. This is for identifying the sizes of floods that occur in the containment building.
15	**CONTROL_RM**. This is for identifying the sizes of floods that occur in the control room.
16	**COOLG_TOWR**. This is for identifying the sizes of floods that occur in the cooling towers.
17	**DIESL_BLDG**. This is for identifying the sizes of floods that occur in the diesel generator building.
18	**EXTERNAL**. This is for identifying the sizes of floods that occur externally to the facility buildings.
19	**PUMP_HOUSE**. This is for identifying the sizes of floods that occur in the pump house.
20	**RADWASTBLD**. This is for identifying the sizes of floods that occur in the radwaste building.
21	**SCREEN_HSE**. This is for identifying the sizes of floods that occur in the screen house.
22	**TURBN_BLDG**. This is for identifying the sizes of floods that occur in the turbine building.
23	**YARD**. This is for identifying the sizes of floods that occur in the yard.
24	**FLOOD_VOL**. This is the total volume of the flood waters in gallons.
25	**FLOOD_RATE**. This is the rate at which flooding occurred in gallons per minute.
26	**FLOOD_TIME**. This is the total of the flooding in minutes.
27	**FLOOD_CAUS**. This field describes the overall cause of the flood.

Table B-2 (Page 3 of 3). Field Descriptions for Plant Descriptive Data	
Field	**Description**
28	**SYSTM_CODE**. This is a numeric representation of the NPE system code. The NPE references given in field 38 are of the following form: NPE BWR-2.VII.F.80-309. For example, the BWR-2 part of the reference simply identifies the plant as a BWR (which can be determined from the plant descriptive data). The 80-309 part simply identifies a page number and a specific incident in the NPE data book. The VII.F part is the NPE system code, which is described in Table B-3. The numeric code for this NPE system code would be 7.6. The 7 comes from the Roman numeral VII, and the 6 comes from the F–the sixth letter of the alphabet.
29	**WATR_SOURC**. This identifies the source of the flood waters.
30	**SRC_CAPCTY**. This indicates the quantity of water contained in the source in gallons.
31	**DETECTMETH**. This briefly identifies the method by which the flood was discovered or detected.
32	**FLOOD_TERM**. This indicates the method used to terminate the flood.
33	**SAFSYSAFCT**. This identifies the safety system(s) whose operation was (were) adversely affected by the flood water.
34	**REDSYSAFCT**. This identifies the redundant system(s)--other than safety systems--whose operation was (were) adversely affected by the flood water.
35	**FLOOD_BAR**. This indicates what barriers (if any) existed to thwart the spread of the flood waters to other areas of the plant or otherwise limit the severity of the adverse effects of the flood water.
36	**CORECTACTN**. This indicates what corrective actions were taken after the occurrence of the flood to try to prevent the recurrence of such floods in the future.
37	**COMMENTS**. This simply presents any additional pertinent comments that apply to the flood incident.
38	**REFERENCES**. This gives any and all pertinent references that describe the flood incident. All references are in the NPE data books. The NPE system identification codes are given in Table B-3.

Table B-3 (Page 1 of 5). NPE System Identification Codes

Light Blue Volume
General Info on NPE
BWR Systems
p. 7

BWR PLANT SYSTEMS OUTLINE

NPE classifies all BWR operational events by the following plant systems, subsystems, and categories. Each section in the BWR-2 volumes corresponds to one of these categories. The descriptions below indicate the more important components and types of problems included in each section. See Menu 11 of the NPE automated retrieval system (NPEars) for an up-to-date listing of plant cross-references to the article numbers of event narratives in these various categories for each unit.

I. FUEL
   Includes uranium fuel pellets and cladding, and fuel assemblies (FAs) - spacers, tie plates and channels

II. REACTOR INTERNALS
   Includes jet pumps, feedwater (FW) & core spray spargers, steam dryer assembly, core support/guide, core shroud

III. REACTOR VESSEL
   Includes reactor pressure vessel (RPV), lines & nozzles - FW & core spray, control rod drive (CRD) return, recirc

IV. CONTROL RODS & DRIVES
   A. CONTROL RODS
      Includes rods, sheaths, blades
   B. DRIVES
      Includes CRDs, hydraulic control units (HCUs), hydraulic supply system, scram discharge header

V. RECIRCULATION, STEAM & RELIEF
   A. PUMPS
      Includes recirc pumps, drives and seals, speed controls, recirc manifold
   B. PIPING
      Includes main steam lines, suction & discharge risers, flow restrictors, bypass lines
   C. RELIEF & SAFETY VALVES
      Includes automatic safety & relief valves (SRVs), main steam isolation valves (MSIVs), automatic depressurization system (ADS) valves
   D. MISCELLANEOUS
      Includes recirc. loop valves (drain valves, sample isolation valves, flow control valves)

VI. TURBINE CYCLE SYSTEMS
   A. TURBINE
      Includes rotor, shaft, bearings, blades, casing, valves (admission, stop, control, intercept), cross-over piping, lube oil system
   B. GENERATOR
      Includes rotor, stator, exciter, bearings, voltage regulator, core monitor, generator cooling systems
   C. CONDENSERS
      Includes tubes, baffles, spargers, shell, water box, hotwell vacuum systems (air ejector, vacuum pump), expansion joint
   D. STEAM
      Includes turbine bypass system, reheaters, moisture separators
   E. CONDENSATE & FEEDWATER
      Includes pumps, LP & HP heaters, condensate demineralizer system, tank
   F. CIRCULATING WATER
      Includes intake structure, discharge canal, circ water pumps, dilution pumps, cooling towers, cooling tower pumps
   G. MISCELLANEOUS
      Includes extraction steam pipes & valves, heater drain system

VII. SAFETY SYSTEMS
   A. REACTOR CORE ISOLATION COOLING (RCIC)
      Includes RCIC pump, drive & speed controls, and associated piping & valves
   B. STANDBY LIQUID CONTROL (SBLC)
      Includes SBLC pumps, tank, explosive valves, piping
   C. CORE SPRAY (CS)
      Includes HP & LP core spray pumps, valves, piping
   D. RESIDUAL HEAT REMOVAL (RHR)
      Includes low pressure coolant injection (LPCI), containment coolers and shutdown cooling systems (including heat exchangers), associated valves & piping
   E. HIGH PRESSURE COOLANT INJECTION (HPCI)
      Includes HPCI turbine, pumps, drives & speed controls, associated valves & piping
   F. MISCELLANEOUS
      Includes isolation condenser systems, containment isolation valves (CIVs), fire protection systems

 Jul 87

Light Blue Volume
General Info on NPE
BWR Systems
p. 8

VIII. AUXILIARY SYSTEMS
- A. REACTOR WATER CLEANUP (RWCU)
  Includes regenerative and non-regenerative heat exchangers, filter-demineralizer units, RWCU pumps
- B. REACTOR BUILDING CLOSED COOLING WATER
  Includes pumps, surge tank, coolers, heat exchangers
- C. MISCELLANEOUS
  Includes service water (SW) systems, steam line drains, sump drains

IX. INSTRUMENTATION & CONTROL (I&C)
- A. NUCLEAR INSTRUMENTATION
  Incore Neutron flux detection I&C, including traversing incore probes (TIPs), source range monitors (SRMs), local power range monitors (LPRMs), intermediate range monitors (IRMs), average power range monitors (APRMs)
- B. REACTOR PROTECTION SYSTEM (RPS)
  Trip channel systems for manual or auto control rod scramming, safe reactor shutdown, including anticipated transient without scram (ATWS) backfits
- C. REACTOR CONTROL
  Includes rod sequence control system (RSCS), manual rod control system (MRCS), rod block monitor (RBM) system, rod position indication system (RPIS), I&C for core performance, power, mode changes
- D. TURBINE CYCLE
  Electro-hydraulic control (EHC) system, including electric pressure regulators (EPRs), mechanical pressure regulators (MPRs), feedwater (FW) flow controllers, condenser hotwell & heater level controls
- E. SAFETY SYSTEMS
  I&C for emergency core coding system (ECCS), engineered safety features (ESF) and other safety system actuations, including rod worth minimizer (RWM), isolation condenser, RCIC, SBLC, CS, RHR, HPCI, SBGT, ADS, torus, main steam line, and fire protection systems
- F. PROCESS SYSTEMS
  I&C for process computer, RWCU, flow, level, and pressure detectors, transmitters, and recorders
- G. MISCELLANEOUS
  Includes I&C for containment sampling and monitoring, incore thermocouples (T/Cs), area radiation monitoring, leak detection, data acquisition, seismic and sonic detection and instrument air systems

X. FUEL HANDLING FACILITIES & SYSTEMS
  Includes refueling bridge, platform, hoist, grapple, spent fuel pool and racks, and associated I&C

XI. ELECTRICAL SYSTEMS
- A. EMERGENCY POWER
  Includes diesel generators (DGs), gas turbine generators, ac uninterruptible power supply (UPS), dc backup, motor-generator (MG) sets, safety buses, batteries, and battery charger
- B. OTHER ELECTRICAL
  Includes main unit transformer, aux transformer, safeguards inverters, motor control centers (MCCs), buses, breakers, relays, fuses, switchgear, on- and off-site distribution lines

XII. LIQUID RADWASTE SYSTEM
  Includes concentrator, demineralizer, filters, collector tanks, drain tanks, sample tanks, surge tank, condensate storage tank, spent resin tank, solid radwaste separators, centrifuges, and hopper, and associated I&C

XIII. GASEOUS RADWASTE SYSTEM
  Includes stack gas and offgas charcoal adsorbers, cryogenic distillate systems, sample pumps, recombiners, HEPA filters, monitors, analyzers, and other I&C

XIV. BUILDINGS & CONTAINMENT
- A. PENETRATIONS
  Includes airlock, manway, hatch, electrical and tubing penetrations, seals, and gaskets to containment and among plant buildings
- B. MISCELLANEOUS
  Includes heating, ventilation and air conditioning (HVAC) systems, suppression chamber (torus etc.) pressure suppression systems, containment atmosphere dilution (CAD) systems, standby gas treatment (SBGT) systems, vacuum breakers, H_2 systems, cranes

XV. MISCELLANEOUS SYSTEMS
  Includes plant air systems, aux boilers, seismic and component restraints (hangers, snubbers, etc.)

XVI. OPERATIONAL PROBLEMS
- A. INSERVICE INSPECTION (ISI)
  Includes operational problems arising from scheduled ISIs
- B. REFUELING
  Includes chiefly errors arising from mishandling of equipment during periods of removal of reactor pressure vessel (RPV) head for initial fuel loading, refueling and spent fuel handling
- C. MISCELLANEOUS
  Includes operator and personnel errors, procedural problems relating to the full range of plant systems, particularly those concerning exposure to radiation or radioactive contamination

REFERENCES

PWR PLANT SYSTEMS OUTLINE

NPE classifies all PWR operational events by the following plant systems, subsystems and categories. Each section in the PWR-2 volumes corresponds to one of these categories. The descriptions below indicate the more important components and types of problems included in each section. See Menu 11 of the NPE automated retrieval system (NPEars) for an up-to-date listing of plant cross-references to the article numbers of event narratives in these various categories for each unit.

I. FUEL
Includes uranium fuel p[illegible]s and cladding, and fuel assemblies (FAs), holddown springs, guide tubes

II. REACTOR INTERNALS
Includes upper guide structure, thermal shield, core barrel, supports for incore instrumentation

III. REACTOR VESSEL
Includes reactor pressure vessel (RPV), nozzles, head bolts, seals

IV. CONTROL RODS & DRIVES
- A. CONTROL RODS
  Includes absorber & poison rods, rod control cluster assemblies (RCCAs), control element assemblies (CEAs)
- B. DRIVES
  Includes magnetic jack control rod drive mechanisms (CRDMs), housings, drive shafts, motors, clutches, latches, grippers

V. REACTOR COOLANT SYSTEM (RCS)
- A. PUMPS
  Includes main reactor coolant pumps (RCPs), casings, flanges, shafts, bearings, seals, motors, impellers, speed controls
- B. PIPING
  Includes main coolant lines, welds, fittings
- C. RELIEF & SAFETY VALVES
  Includes safety/relief valves (SRVs) (including pressurizer SRVs), power operated relief valves (PORVs)
- D. STEAM GENERATORS (SGs)
  Includes SG shell, internal tubing, support plates, nozzles, manw[illegible] blowdown lines, valves
- E. PRESSURIZER
  Includes pressurizer shell, internal heaters, manway, nozzles, pressurizer relief tank (PRT), PORV block valves, resistance temperature detectors (RTDs), manifold valves
- F. MISCELLANEOUS
  Includes additional RCS loop valves not associated with above categories

VI. TURBINE CYCLE SYSTEMS
- A. TURBINE
  Includes main turbine, HP and LP cylinders, including casings, rotors, shafts, blades, bearings stop and control valves, drain and crossover l[illegible]s, lube oil system
- B. GENERATOR
  Main generator system includes rotor, stator, exciter, brushes, bearings, coils, voltage regulator, armature, commutator, windings, generator cooling, seal oil systems
- C. CONDENSERS
  Main condenser includes tubes, baffles, vacuum pump, air ejector, hotwell, shells, water boxes
- D. STEAM
  Includes turbine bypass and atmospheric steam dump valves, SRVs, main steam isolation valves (MSIVs), moisture separator/reheaters (MSRs), main steam line (MSL) piping
- E. CONDENSATE & FEEDWATER
  Includes condensate/booster, feedwater (FW) and aux FW pumps, condensate storage tank (CST), demineralizer system, LP and HP heaters, associated valves and piping
- F. CIRCULATING WATER
  Includes intake structures, screens, cooling towers, discharge gates and canals, associated pumps and valves
- G. MISCELLANEOUS
  Includes heater drain system

VII. SAFETY SYSTEMS
- A. EMERGENCY CORE COOLING (ECCS)
  Includes safety injection (SI), upper head injection (UHI) systems, SI accumulators, boron injection tank (BIT)
- B. CONTAINMENT PRESSURE SUPPRESSION
  Includes containment spray, ice condensers, recirculation spray, chemical addition tanks
- C. CONTAINMENT ATMOSPHERE COOLING
  Includes containment fan coil units (CFCUs), containment air recirculation

 Jul 87

Table B-3 (Page 4 of 5). NPE System Identification Codes

Light Blue Volume
General Info on NPE
PWR Systems
p. 10

D. CONTAINMENT ISOLATION
Includes general containment isolation valves (CIVs) (for specific CIVs see appropriate section)

E. MISCELLANEOUS
Includes fire systems, containment H_2 venting, purge & recombiners, security systems, respirators

VIII. AUXILIARY SYSTEMS

A. COOLANT VOLUME, PURIFICATION, CHEMICAL, SAMPLING
Includes chemical and volume control system (CVCS), charging pumps, post-accident sampling system (PASS), boric acid storage tank (BAST), boron recycle system, letdown lines and valves

B. AUXILIARY COOLING
Includes residual heat removal (RHR), component cooling water, service water (SW) and essential raw cooling water systems, pumps, HXs, and associated valves and piping

C. MISCELLANEOUS
Includes RCS drains, containment sump valves

IX. INSTRUMENTATION & CONTROL (I&C)

A. NUCLEAR INSTRUMENTATION
I&C for incore neutron flux monitoring, including source and intermediate range monitors (SRMs & IRMs), power range monitors, related amplifiers and indicators

B. REACTOR PROTECTION SYSTEM (RPS)
I&C for manual or auto reactor trip channel actuation, including RCS loop resistance temperature detectors (RTDs), reactor trip breakers (RTBs), pressurizer pressure & level transmitters, SG level transmitters and FW flow transmitters. Includes anticipated transient without scram (ATWS) backfits.

C. REACTOR CONTROL
Includes the integrated control system (ICS), axial flux monitors, control rod positioning and other rod and core performance monitoring and control I&C

D. TURBINE CYCLE
I&C for manual or auto, turbine trip channel actuation and turbine, generator and FW control, including electro-hydraulic control (EHC), vibration and wear probes, governors, FW and aux FW flow and ICS (B&W)

E. SAFETY SYSTEMS
Includes I&C for actuation of emergency core cooling systems (ECCS), engineered safety features (ESF), solid state protection system (SSPS), fire systems, containment pressure suppression and isolation, and main steam isolation, RWST level, TGIS, TGIS butane monitor, containment sump level, BWST level, steam line dp, RPV level, B&W SG level & flow, aux alarm annunciator

F. PROCESS SYSTEMS
I&C for process computer, RCP pressure seal sensing, CVCS tank level, heat tracing controls, accumulator level, CFCU service water (SW) flow, pH instruments

G. REACTOR COOLANT CONTROL
I&C for RCS flow, subcooling monitors, pressurizer level (B&W)

H. MISCELLANEOUS
I&C for containment sampling & monitoring, general area radiation monitoring, I&C air, incore thermocouples (T/Cs), N_2 system valves and loose parts monitor

X. FUEL HANDLING FACILITIES & SYSTEMS
Includes reactor cavity, refueling canal, fuel transfer system, spent fuel pool, and racks, new fuel storage, cranes and lifting devices, tools and fixtures, and associated I&C

XI. ELECTRICAL SYSTEMS

A. EMERGENCY POWER
Includes batteries, diesel generators (DGs), battery chargers, motor generator (MG) sets, and associated I&C

B. OTHER ELECTRICAL
Electrical distribution systems include buses, breakers, inverters, transformers, motor control centers (MCCs), switchgear, on- and offsite distribution lines, and associated I&C

XII. LIQUID RADWASTE SYSTEM
Includes liquid and solid radwaste tanks, evaporators, filters, valves, chemical drains, piping, associated I&C

XIII. GASEOUS RADWASTE SYSTEM (see 56)
Includes waste gas processing, aux building gas treatment, waste gas decay tank (WGDT), compressor, H_2 recombiner, filters, stack monitors, associated I&C

XIV. BUILDINGS & CONTAINMENT

A. PENETRATIONS
Includes airlocks, hatches, manways, electrical and pipe penetrations, fire doors, seals, gaskets to containment and among plant buildings

B. MISCELLANEOUS
Includes heating, ventilation and air conditioning (HVAC), fire dampers, charcoal absorbers, containment purge butterfly valves and [illegible] purge isolation valves

Table B-3 (Page 5 of 5). NPE System Identification Codes

Light Blue Volume
General Info on NPE
PWR Systems
p. 11

XV. MISCELLANEOUS SYSTEMS

Includes plant air systems, snubbers, pipe and building supports, nonradioactive waste neutralizing system, general valve operator problems, rupture discs and rescue breathing apparatus

XVI. OPERATIONAL PROBLEMS

A. INSERVICE INSPECTION (ISI)

Includes operational problems arising from scheduled ISIs

B. REFUELING

Includes operational errors occurring during initial fuel load, refueling or spent fuel handling

C. MISCELLANEOUS

Includes operator errors and procedural problems relating to the full range of plant systems, especially those involving radiation exposure or contamination

REFERENCES

Jul 87

APPENDIX F

STADIC4 UNCERTAINTY MODEL

APPENDIX F

F.1 FORTRAN CODING FOR UNCERTAINTY ANALYSIS OF CORE DAMAGE FREQUENCY (PLANT DAMAGE STATE)

```
      SUBROUTINE SAMPLE(X,Y)
C
C SAMPLE routine for Plant Damage States, based on 19 MAY88 results
C      FINAL MODEL USED FOR SHUTDOWN STUDY  MAY 1988
C
      DIMENSION X(200),Y(150)
C
C********** CODE BLOCK 1, Uncovery Times **********
C
C ASSIGN VARIABLES FOR TIME TO RHR INITIATION
C ( X(1) through X(12) are the time in the 12 Procedure Trees)
C
      TA1=X(13)
      TB1=X(14)
      TC1=X(15)
      EM =X(23)
      XL =X(24)
C
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE A OUTAGES
C
      TA1SS=TA1+X(1)
      TA6SS=TA1SS+X(2)
C
C THESE STATEMENTS COMPUTE RANDOM INITIATION TIMES IN TYPE A OUTAGES
C
      TA1S=TA1+X(1)*X(22)
      TA6S=TA1SS+X(2)*X(22)
C
C THESE STATEMENTS COMPUTE TIMES TO CORE UNCOVERY FOR AX AND AW CONDITIONS
C
      TA1W=TA1S+TCUW(TA1S,EM)
      TA6W=TA6S+TCUW(TA6S,EM)
C
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE B OUTAGES
C
      TB1SS=TB1+X(3)
      TB2SS=TB1SS+X(4)
      TB5SS=TB2SS+X(5)
      TB6SS=TB5SS+X(6)
C
C THESE STATEMENTS COMPUTE RANDOM INITIATION TIMES FOR TYPE B OUTAGES
C
      TB1S=TB1+X(3)*X(22)
      TB2S=TB1SS+X(4)*X(22)
      TB5S=TB2SS+X(5)*X(22)
      TB6S=TB5SS+X(6)*X(22)
C
C THESE STATEMENTS COMPUTE CORE UNCOVERY TIMES FOR BX AND BW CONDITIONS
C
      TB1W=TB1S+TCUW(TB1S,EM)
      TB2X=TB2S+T12X(TB2S,XL,EM)
      TB5W=TB5S+TCUW(TB5S,EM)
      TB6W=TB6S+TCUW(TB6S,EM)
```

```
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE C OUTAGES
C
      TC1SS=TC1+X(7)
      TC2SS=TC1SS+X(8)
      TC3SS=TC2SS+X(9)
      TC4SS=TC3SS+X(10)
      TC5SS=TC4SS+X(11)
      TC6SS=TC5SS+X(12)
C
C THESE STATEMENTS COMPUTE RANDOM INITIATION TIMES FOR TYPE C OUTAGES
C
      TC1S=TC1+X(7)*X(22)
      TC2S=TC1SS+X(8)*X(22)
      TC3S=TC2SS+X(9)*X(22)
      TC4S=TC3SS+X(10)*X(22)
      TC5S=TC4SS+X(11)*X(22)
      TC6S=TC5SS+X(12)*X(22)
C
C THESE STATEMENTS COMPUTE CORE UNCOVERY TIMES FOR TYPE CX AND CW CONDITIONS
C
      TC1W=TC1S+TCUW(TC1S,EM)
      TC2W=TC2S+TCUW(TC2S,EM)
      TC3X=TC3S+T12X(TC3S,XL,EM)
      TC3W=TC3S+TCUW(TC3S,EM)
      TC4X=TC4S+T12X(TC4S,XL,EM)
      TC5W=TC5S+TCUW(TC5S,EM)
      TC6W=TC6S+TCUW(TC6S,EM)
C
C********** END OF CODE BLOCK 1 **********
C
C********** CODE BLOCK 2. Shutdown Times & Fractions **********
C
C COMPUTE HOURS SHUTDOWN PER YEAR (= 1 "SHUTDOWN YEAR") = TSD,
C ANNUAL FRACTION OF YEAR SHUTDOWN (FSD), AND
C HOURS PER YEAR IN W, X, & Y (TW,TX,TY)
C
      FA = X(25)
      FB = X(26)
      FC = X(27)
      TSD = FA*(X(1)+X(2)) + FB*(X(3)+X(4)+X(5)+X(6)) +
     1       FC*(X(7)+X(8)+X(9)+X(10)+X(11)+X(12))
      FSD = TSD/(TSD + 6136.0)
      TW = FA*(X(1)+X(2)) + FB*(X(3)+X(5)+X(6)) +
     1       FC*(X(7)+X(8)+X(11)+X(12))
      TX = FB*X(4) + FC*X(10)
      TY = FC*X(9)
C
C FRX AND FRW ARE THE FRACTION OF SHUTDOWN TIME IN X AND W
C
      FRX = TX/TSD
      FRW = TW/TSD
C
C********** END OF CODE BLOCK 2 **********
```

```
C********** CODE BLOCK 3. IE Initiators **********
C
C COMPUTE NON-PROCEDURAL INITIATING EVENT FREQUENCIES
C  1. FIRE INITIATORS
C
      FIRAUX = X(38)
      FTBSD  = X(39)
      FSOR   = X(40)
      FTNL   = X(41)
      O1TO   = X(42)
      FHS    = X(43)
      FP1A   = X(44)
      FP1AS  = X(45)
      O2TO   = X(46)
      FTBOS  = X(47)
      FSOAX  = FSD * FRX * FIRAUX * FSOR
      FSOAW  = (FRW/FRX) * FSOAX
      FPABX  = FSD * FRX * FIRAUX * FP1A * FP1AS * O2TO
      FPABW  = (FRW/FRX) * FPABX
      FETOX  = FSD*FRX*FIRAUX*FTNL*O1TO*FHS
C
C  2. LOSS OF PCC INITIATORS
C
      FPR    = X(48)
      ZMONBD = X(49)
      FM1X   = X(50)
      FM1W   = X(34)
      ZBPCWR = X(51)
      ZBPCWS = X(52)
      FPA    = X(53)
      FPC    = X(54)
      FM2W   = X(55)
      BB     = X(56)
      PCC2A  = X(57)
C
      FM1XP  = 0.5 * FM1X
      FM1WP  = 0.5 * FM1W
C
      FLPCAX = (FPR*TX)*(ZIPMOS+FM1XP+FPR*ZMONBD)+ZBPCWR*FPR*ZMONBD
      FLPCAW = (FPR*TW)*(ZIPMOS+FM1WP+FPR*ZMONBD)+ZBPCWR*FPR*ZMONBD
      FPCC1B = PCC2A + 2.0*BB*FM1WP + FM2W
      FPCC2B = PCC2A + 2.0*BB*FM1XP
C
C  3. LOSS OF SW INITIATORS
C
      ZBPSWR = X(58)
      FOP1CT = X(59)
      FCTA   = X(60)
      FLSWAX = (FPR * TX * (ZIPMOS + FM1XP + FPR * ZMONBD)
     1          + ZBPSWR * FPR * ZMONBD) * (FOP1CT + FCTA + FM1XP)
      FLSWAW = (FPR * TW * (ZIPMOS + FM1WP + FPR * ZMONBD)
     1          + ZBPSWR * FPR * ZMONBD) * (FOP1CT + FCTA + FM1WP)
C
C  4. LOSP INITIATOR
C
      FLOSPP = X(61)
      FLOSPV = X(62)
      FLOSPX = (FSD * FLOSPP + FLOSPV) * FRX
      FLOSPW = (FRW/FRX) * FLOSPX
C
C  5. SEISMIC INITIATOR
C
      SSBOW  = X(135) * FSD * FRW
      SSBOX  = X(136) * FSD * FRX
      SLLW   = X(137) * FSD * FRW
```

```
C  6  INITIATOR L5
C
      OPICS = X(138)
      NRICS = X(139)
      XL5   = FC * OPICS * NRICS
C
C  7  INITIATOR LS
C
      XLSCV  = X(152)
      XLSFR  = 0.67
      XLSNR  = X(153)
      EVNTLS = 0.5 * XLSCV * TW * XLSFR * XLSNR
C
C********** END OF CODE BLOCK 3 **********
C
C********** CODE BLOCK 4. Procedure Tree Initiators **********
C
C Compute Frequencies of Procedure Tree Endstates
C (W1A, W6A, W3N, W5N, X3N, X4N, X5N, X6N, W3C)
C COMPUTE RHR SYSTEM SPLIT FRACTIONS (TOP EVENT RM)
C
C 1  W1A
C
      XNC1   = X(64)
      XNC3   = X(65)
      XLIHW1 = X(66)
      XLIHW2 = X(67)
      XLIOP1 = X(68)
      XLINR1 = X(69)
      XLINR2 = X(70)
      CC1OP1 = X(71)
      CC1OP2 = X(72)
      PUHW1  = X(73)
      PUHW2  = X(74)
      PUOP1  = X(75)
      XLMOP1 = X(76)
      XLMOP2 = X(77)
      XLMNR1 = X(78)
      TL1    = X(79)
      XISOP1 = X(80)
      XISOP2 = X(81)
C
      XLI1 = 4.0*XLIOP1*XLINR1 + XLIOP1*XLINR2 + XLIHW1
      XLI2 = 3.0*XLIOP1*XLINR1 + 5.0*XLIOP1*XLINR2 + XLIHW2
C
      CC1 = CC1OP1 + CC1OP2
C
      PU1 = 3.0*PUOP1 + PUHW1
      PU2 = 3.0*PUOP1 + PUHW2
C
      XLM5 = (XLMOP1 + (X(5)*XLMOP2)/24.0 )*XLMNR1
      XLM6 = (XLMOP1 + (X(11)*XLMOP2)/24.0 )*XLMNR1
C
      XIS1 = XISOP1*XISOP2
C
      W1ATA1 = FA*XNC1
      W1ATA6 = FA*(XIS1 + XLI1)
      W1ATB5 = FB*(CC1 + PU1 + XLM5 + TL1)
      W1ATB6 = FB*XIS1
      W1ATC1 = FC*XNC3
      W1ATC5 = FC*(CC1 + TL1 + PU2 + XLM6)
      W1ATC6 = FC*(XIS1 + XLI2)
      W1A = W1ATA1+W1ATA6+W1ATB5+W1ATB6+W1ATC1+W1ATC5+W1ATC6+0.00139
```

```
C 2  W6A
C
      RV1PT  = X(82)
      RV1B   = X(83)
      RV1OP3 = X(84)
C
      RV1 = RV1PT*RV1PT*RV1OP3 + RV1PT*RV1B*RV1OP3
C
      W6ATA1 = FA*RV1
      W6ATB1 = FB*RV1
      W6ATC1 = FC*RV1
      W6A = W6ATA1+W6ATB1+W6ATC1
C
C 3  W3N
C
      SALPT1 = X(85)
      SAOP1  = X(86)
      SAOP2  = X(87)
      SANR1  = X(88)
      SAOP3  = X(89)
      SANR2  = X(90)
      SANR3  = X(91)
      SALPT2 = X(92)
      SALPB  = X(93)
      CT1OP1 = X(94)
      CT1OP2 = X(95)
      CT1OP3 = X(96)
      CT1NR2 = X(97)
      CT1NR3 = X(98)
      TV1OP1 = X(99)
      TV1OP2 = X(100)
      Z1TRLR = X(101)
      XLMOP3 = X(102)
      XLMNR2 = X(103)
      XLMNR3 = X(104)
C
      SA1 = SALPT1 * X(1)
      SA3 = 2.0*(SAOP1*SANR1) + SALPT1*X(7)
      SA4 = 2.0*(SAOP1+SAOP2)*SANR1 + SALPT1*X(7)
      SA6 = (X(8)/24.0)*SAOP3*SANR2 + SALPT2*X(8)
      SAC = SALPB*X(11)
      SAE = SALPB*X(2)
      SAH = SALPB*X(12)
C
      CT1 = CT1OP1 + CT1OP2*CT1NR2 + CT1OP3*CT1NR3
      TV1 = TV1OP1*TV1OP2
      X1O2 = Z1TRLR*X(8)
      XLM2 = 3.0*XLMOP3*XLMNR3
C
      W3NTA1 = FA*SA1
      W3NTA6 = FA*SAE
      W3NTC1 = FC*(SA3 + CT1 * SA4)
      W3NTC2 = FC*(TV1 + SA6 + X1O2 + XLM2)
      W3NTC5 = FC*SAC
      W3N = W3NTA1+W3NTA6+W3NTC1+W3NTC2+W3NTC5+0.00035
```

```
C 4. W5N
C
      FRH1R = X(26)
C
      RM1 = FRH1R*X(1)
      RM2 = FRH1R*X(3)
      RM3 = FRH1R*X(7)
      RM4 = FRH1R*X(4)
      RM5 = FRH1R*X(8)
      RM6 = FRH1R*X(9)
      RM7 = FRH1R*X(10)
      RM8 = FRH1R*X(5)
      RM9 = FRH1R*X(11)
      RMA = FRH1R*X(2)
      RMB = FRH1R*X(12)
C
      W5NTA1 = FA*RM1
      W5NTA6 = FA*RMA
      W5NTB5 = FB*RM8
      W5NTC1 = FC*RM3
      W5NTC2 = FC*RM5
      W5NTC5 = FC*RM9
      W5NTC6 = FC*RMB
      W5N = W5NTA1+W5NTA6+W5NTB5+W5NTC1+W5NTC2+W5NTC5+W5NTC6+
     1      0.00086
C
C 5. X3N
C
      DR1OP1 = X(105)
      DR1NR1 = X(106)
      RF1OP1 = X(107)
      RF1NR1 = X(108)
      DM1    = X(109)
C
      SA8 = (X(10)/24.0)*SAOP3*SANR3 + SALPT2*X(10)
      SA9 = (X(10)/24.0)*SAOP3*SANR2 + SALPT2*X(10)
      SA5 = (X(4)/24.0)*SAOP3*SANR3 + SALPT2*X(4)
C
      XIO1 = ZITRLR*X(4)
      DR1 = DR1OP1*DR1NR1
      RF1 = RF1OP1*RF1NR1
      XLM3 = 3.^^XLMOP3*XLMNR2
C
      X3NTB2 = FB*((1.0-RM4)*(SA5 + XIO1 + DR1))
      X3NTC4 = FC*(1.0-RM7)*((1.0-DM1)*SA8 + DM1*SA9 + RF1 + XLM3)
      X3N = X3NTB2 + X3NTC4 + 0.00046
C
C 6. X4N, X5N, and X6N
C
      CD1OP1 = X(110)
      CD1OPP = X(111)
      CD1OP2 = X(112)
      BR1    = X(113)
C
      CD1 = CD1OP1*(CD1OPF + CD1OP2)
C
      X4NTC4 = FC*(1.0-RM7)*(CD1 + (1.0-DM1)*SA8*BR1)
      X4N = X4NTC4 + 0.000049
C
      X5NTB2 = FB*RM4
      X5NTC4 = FC*RM7
      X5N = X5NTB2 + X5NTC4 + 0.0007
```

```
      X6NTC4 = FC*RMT*BR1
      X6N = X6NTC4 + 0.0000029
C
C 7. W3C
C
      CT2A  = X(176)
      CT2B  = X(177)
      CT2C  = X(178)
C
      CT2 = (CT2A + CT2B) * CT2C
      SAA = SALPB * X(5)
C
      W3CTB5 = FB * SAA * TL1
      W3CTC5 = FC * EAC * (TL1 + CT2*CC1)
      W3CR   = 0.000000052
      W3C    = W3CTB5 + W3CTC5 + W3CR
C
C********** END OF CODE BLOCK 4 **********
C
C********** CODE BLOCK 5. Frontline Tree Operator Events OR AND OL **********
C
C     COMPUTE SPLIT FRACTIONS FOR OR AND OL
C
      B = X(63)
C
C COMPUTE TIME AVAILABLE FOR OR1 ACTION. FOR EVENTS IN EACH PROC TREE. =
C (TIME FROM 100% PWR TO CORE DAMAGE) - (TIME FROM 100% PWR TO START OF EVENT
C                                      - 1.5 FOR TIME TO INITIATE ACTION
C
      TRWA1 = TA1W - TA1S - 1.5
      TRWA6 = TA6W - TA6S - 1.5
      TRWB1 = TB1W - TB1S - 1.5
      TRWB5 = TB5W - TB5S - 1.5
      TRWB6 = TB6W - TB6S - 1.5
      TRWC1 = TC1W - TC1S - 1.5
      TRWC2 = TC2W - TC2S - 1.5
      TRWC3 = TC3W - TC3S - 1.5
      TRWC5 = TC5W - TC5S - 1.5
      TRWC6 = TC6W - TC6S - 1.5
C
C COMPUTE OR1 FOR W CASES
C
      XMD   = 0.15
      OR1A1 = SWAIN(TRWA1,B)*XMD
      OR1A6 = SWAIN(TRWA6,B)*XMD
      OR1B1 = SWAIN(TRWB1,B)*XMD
      OR1B5 = SWAIN(TRWB5,B)*XMD
      OR1B6 = SWAIN(TRWB6,B)*XMD
      OR1C1 = SWAIN(TRWC1,B)*XMD
      OR1C2 = SWAIN(TRWC2,B)*XMD
      OR1C3 = SWAIN(TRWC3,B)*XMD
      OR1C5 = SWAIN(TRWC5,B)*XMD
      OR1C6 = SWAIN(TRWC6,B)*XMD
C
C COMPUTE OR2 FOR X CASES
C
      TRXB2 = TB2X - TB2S - 1.0
      TRXC4 = TC4X - TC4S - 1.0
C
      OR2B2 = SWAIN(TRXB2,B)
      OR2C4 = SWAIN(TRXC4,B)
```

```
C COMPUTE OR3 FOR X CASES
C
      TR3B2 = TB2X - TB2S - 0.667
      TR3C4 = TC4X - TC4S - 0.667
      OR3B2 = SWAIN(TR3B2,B)
      OR3C4 = SWAIN(TR3C4,B)
C
C COMPUTE OR4 FOR X CASES
C
      TR4B2 = TB2X - TB2S - 1.25
      TR4C4 = TC4X - TC4S - 1.25
      OR4B2 = 2.0 * SWAIN(TR4B2,B)
      OR4C4 = 2.0 * SWAIN(TR4C4,B)
C
C COMPUTE OR5 FOR X CASES
C
      TR5B2 = TB2X - TB2S - 1.0
      TR5C4 = TC4X - TC4S - 1.0
      OR5B2 = 5.0 * SWAIN(TR5B2,B)
      OR5C4 = 5.0 * SWAIN(TR5C4,B)
C
C COMPUTE TIMES FOR OL ACTION
C
      TRLA1 = TRWA1 + 1.0
      TRLA6 = TRWA6 + 1.0
      TRLB1 = TRWB1 + 1.0
      TRLB5 = TRWB5 + 1.0
      TRLB6 = TRWB6 + 1.0
      TRLC1 = TRWC1 + 1.0
      TRLC5 = TRWC5 + 1.0
      TRLC6 = TRWC6 + 1.0
C
C COMPUTE OL1 FOR DIFFERENT PROCEDURE TREES
C
      OL1A1 = SWAIN(TRLA1,B)
      OL1A6 = SWAIN(TRLA6,B)
      OL1B1 = SWAIN(TRLB1,B)
      OL1B5 = SWAIN(TRLB5,B)
      OL1B6 = SWAIN(TRLB6,B)
      OL1C1 = SWAIN(TRLC1,B)
      OL1C5 = SWAIN(TRLC5,B)
      OL1C6 = SWAIN(TRLC6,B)
C
C COMPUTE OL2 FOR TREE C3
C
      TRYC3 = TC3X - TC3S - 0.5
      OL2C3 = SWAIN(TRYC3,B) * 2.0
```

```
C********** CODE BLOCK 6. Plant Model Split Fractions **********
C
C Top Event RR
C
      ZIPMOS = X(29)
      ZBPDHS = X(30)
      ZBPDHR = X(31)
      FOP1   = X(32)
      FOP2   = X(33)
      ZIVMOD = X(35)
      FNR    = X(36)
      FNRP   = X(37)
      FRH1PM = FM1W
      FOP1R1 = (FOP1+FOP2)*FNR
      FOP2R1 = (FOP1+FOP2)*FNRP
      FRH1S  = ZIPMOS + ZIVMOD
      FRHCCS = FRH1S*ZBPDHS
      FRHCCR = (3.36/3.89)*FRH1R*ZBPDHR
      RR4 = FRH1S + FOP2R1 + FRH1R*24.0
      RRZ = RR4 + FRH1PM
      RRY = RR4
      RRB = FRH1S + FRH1R*24.0
      RRA = (FRH1S + FOP1R1 + FRH1R*24.0)*RR4 + FRHCCS + FRHCCR*24.0
C
C Top Event LC
C
      XLCO1  = X(114)
      XLCO2  = X(115)
      XLCNR  = X(116)
      XLCOCF = X(117)
      XLCORT = X(118)
      XLCOBT = X(119)
      XLCRW  = X(120)
      XLCOPC = X(121)
      XLCFD1 = X(122)
      XLCFD2 = X(123)
      XLCOFD = X(124)
      XLCSLH = X(125)
      XLCS1B = X(126)
      XLCM1X = X(127)
      XLCPV  = X(128)
      XLCPVB = X(129)
      XLCFW2 = X(130)
      XLCFW5 = X(131)
      XLCSFP = X(132)
      XLCAOV = X(133)
      XLCNR2 = X(134)
C
      XLCLLL = X(149)
      XLCSA  = X(150)
      XLCHA  = X(151)
C
      XLC1FB = 2.0*XLCO1*(XLCNR+XLCO2) + XLCOCF*XLCORT + XLCRW*XLCOBT
      XLC2FB = 10.0*XLCO1*(XLCNR+XLCO2) + XLCOPC + XLCRW
      XLCFD3 = XLCOFD + XLCSLH + XLCS1B*FM1X
      BLD1   = XLCPV*XLCPV + XLCPV*XLCPVB
```

```
      XLC1   = XLC1FB + XLCFD1 + BLD1
      XLC3   = XLC1FB + XLCFD2 + BLD1
      XLC2   = XLC1FB + XLCFD3 + BLD1
      XLC4   = XLC2FB
      XLC8   = (XLCFW2 + 2.0*XLCAOV) * XLCNR2
      XLCA   = XLCLLL + XLCSA + XLCHA + FM1W
      XLCC   = XLCA
C
C Top Events GA and GB with Recovery
C
      EPR18  = X(140)
      DGAB24 = X(174)
      DGA24  = X(175)
C
      GA2    = DGAB24 + DGA24
      GA2GBD = DGAB24
C
C Top Events PA and PB
C
      PCC1A  = X(141)
      PCC2B  = X(142)
C
      PB3    = PCC2B + 2.0*BB*FM1WP + FM2W
      PBA    = FPCC1B
      PBC    = FPCC2B
      PA1PBB = PCC1A + 2.0*PCC2A*(2.0*BB*FM1WP + FM2W)
      PB1    = PCC2A + 2.0*BB*FM1WP + FM2W
      PA1    = PCC2A + 2.0*BB*FM1WP + PA1PBB
      PB2    = PCC2A + 2.0*BB*FM1XP
C
C Top Events WA, WB
C
      SWABP  = X(143)
      SWAP   = X(144)
      SWA    = X(145)
      SWAA   = X(146)
      SWCTA  = X(147)
      SWOP1  = X(148)
C
      WA1    = (SWA + 2.0*SWAA*FM1WP) * (FCTA + FM1WP + FOP1CT)
      [illegible]    = (SWA + 2.0*SWAA*FM1WP + FM2W) * (FCTA+FM1WP+FOP1CT)
      WBC    = (SWA + 2.0*SWAA*FM1XP) * (FCTA + FM1XP + FOP1CT)
      WA3BG  = SWABP + 2.0*SWAP*FM2W
      WA4B1  = SWABP
      WA4    = SWAPB + SWAP
C
C Top events OC1, IR1, and OD1
C
      OC1OP1 = X(154)
      OC1OP2 = X(155)
      OC1NR  = X(156)
      OC1VC1 = X(157)
      OC1    =  OC1OP1 + OC1OP2*OC1NR + OC1VC1
      XIROP1 = X(158)
      XIRHW1 = X(159)
      XIR1   = XIROP1 + XIRHW1
      OD1    = X(173)
```

```
C Top Events SP and EH
C
      SPOP1  = X(160)
      SPNR   = X(161)
      SPOUT  = X(162)
      SPOUTP = X(163)
      SP1    = SPOP1*SPNR + 2.0*SPOUT
      SP2    = SPOP1*SPNR + 2.0*SPOUTP
C
      EHF1   = X(164)
      EHF2   = X(165)
      EHF3   = X(166)
      EH2IPM = X(167)
      EH2IVA = X(168)
      EHOP1  = X(169)
      EHNR   = X(170)
      EHOP2  = X(171)
      EHOPEH = X(172)
C
      EHOPEH1 = 0.05
      EHPNRHW = 0.0015
      EHPNR1 = EHOPEH1*EHNR + EHPNRHW
      EHFTO  = (EHF1*EHF2*EHF3)/TW
      EHPNR  = EHOPEH*EHNR + EHPNRHW
      EHHW2  = 0.4 * EH2IVA
      EHPL2  = EHHW2 + EHOP2*EHNR
      EHPL4  = EHHW2
      EHPL7  = EHHW2 + EHOP1*EHNR
C
      EH1    = EHFTO*EHPNR1 + EHPL7
      EH2    = EHPL2
      EH5    = EHFTO + EHPL2
      EH6    = EHFTO
      EH7    = EHFTO*EHPNR + EHPL7
C
C********** END OF CODE BLOCK 6 **********
C
C-********* CODE BLOCK 7. Core Melt Sequences **********
C
      CM1    = X5NTB2*OR2B2 + X5NTC4*OR2C4
      CM2    = X3NTB2*OR3B2 + X3NTC4*OR3C4
      CM3    = EVNTLS * XLCC
      CM4    = SSBOW
      CM5    = W1A * OC1 * XIR1 * XLCA
C
      CM6    = X6N * XLC1
      CM7    = X5N * RR4 * XLC1
      CM8    = EVNTLS * PBA
      CM9    = W1A * PBA * OC1 * XIR1
      CM10   = SSBOX
C
      CM11A1 = W5NTA1 * OR1A1
      CM11A6 = W5NTA6 * OR1A6
      CM11B5 = W5NTB5 * OR1B5
      CM11C1 = W5NTC1 * OR1C1
      CM11C2 = W5NTC2 * OR1C2
      CM11C5 = W5NTC5 * OR1C5
      CM11C6 = W5NTC6 * OR1C6
      CM11R  = 0.00086 * OR1A1
      CM11   = CM11A1+CM11A6+CM11B5+CM11C1+CM11C2+CM11C5+CM11C6+CM11R
C     Note that remainder of W5N frequency is assigned to Tree A1
```

```
      CM12B2 = FLOSPX * GA2GBD * OR5B2
      CM12C4 = FLOSPX * GA2CBD * OR5C4
      CM12   = CM12B2 + CM12C4
C
      CM13   = X4N * OR3C4
C
      CM14B2 = FLPCAX * ( FB*X(4)/TX ) * OR2B2
      CM14C4 = FLPCAX * ( FC*X(10)/TX ) * OR2C4
      CM14   = CM14B2 + CM14C4
C
      CM15   = FLOSPX * WA4B1 * XLC4
C
      CM16B2 = FLOSPX * ( FB*X(4)/TX ) * GA2 * OR2B2
      CM16C4 = FLOSPX * ( FC*X(10)/TX ) * GA2 * OR2C4
      CM16   = CM16B2 + CM16C4
C
      CM17   = CM1 * SP2
C     Note below that CM17 is NOT counted in the CM total since
C     it is included in sequence CM1.
C
      CM18   = CM2 * SP2
C     Note below that CM18 is NOT counted in the CM total since
C     it is included in sequence CM2.
C
      CM19B2 = FSGAX * ( FB*X(4)/TX ) * OR2B2
      CM19C4 = FSGAX * ( FC*X(10)/TX ) * OR2C4
      CM19   = CM19B2 + CM19C4
C
      CM20   = SLLW
C
      CM21A1 = W3NTA1 * OR1A1
      CM21A6 = W3NTA6 * OR1A6
      CM21C1 = W3NTC1 * OR1C1
      CM21C2 = W3NTC2 * OR1C2
      CM21C5 = W3NTC5 * OR1C5
      CM21R  = 0.00035 * OR1A1
      CM21   = CM21A1 + CM21A6 + CM21C1 + CM21C2 + CM21C5 + CM21R
C     Note that remainder of X3N frequency is assigned to Tree A1
C
      CM22   = FPABX * XLC4
C
      CM23   = X6N * OR4C4
C
      CM24   = W1A * PA1PBB * OC1
C
      CM25   = FLPCAX * RRY * XLC2
C
      CM26   = FLOSPX * GA2 * RRY * XLC2
C
      CM27   = FSGAX * RRY * XLC2
C
      CM28   = X5N * PBC * XLC3
C
      CM29   = FLPCAW * PB1 * XLC8
C
      CM30   = EVNTLS * WBA
C
      CM31   = FETGX * XLC2
C
      CM32   = W1A * WBA * OC1 * XIR1
C
      CM33   = FSGAW * PB1 * XLC8
```

```
C
      CM      = CM1 +CM2 +CM3 +CM4 +CM5 +CM6 +CM7 +CM8 +CM9 +CM10+
     1          CM11+CM12+CM13+CM14+CM15+CM16          +CM19+CM20+
     1          CM21+CM22+CM23+CM24+CM25+CM26+CM27+CM28+CM29+CM30+
     1          CM31+CM32+CM33
      CMT     = CM/0.90593
C
C
C Sequences for PDS R2D
C
      R2D1   = CM1
      R2D2   = CM2
      R2D3   = CM3
      R2D4   = CM5
      R2D5   = CM6
      R2D6   = CM7
      R2D7   = CM8
      R2D8   = CM9
      R2D9   = CM10
      R2D10  = CM12
      R2D11  = CM13
      R2D12  = CM14
      R2D13  = CM15
      R2D14  = CM16
      R2D15  = CM19
      R2D16  = CM20
      R2D17  = CM22
      R2D    = R2D1+ R2D2+ R2D3+ R2D4+ R2D5+
     1         R2D6+ R2D7+ R2D8+ R2D9+ R2D10+
     1         R2D11+R2D12+R2D13+R2D14+R2D15+
     1         R2D16+R2D17
      R2DT   = R2D/0.91085
C
C Sequences for PDS R2P
C
      R2P1   = CM1 * SP2
      R2P2   = CM2 * SP2
      R2P3   = CM3 * SP2
      R2P4   = CM5 * SP2
      R2P5   = CM6 * SP2
      R2P6   = CM7 * SP2
      R2P7   = CM8 * SP2
      R2P8   = CM9 * SP2
      R2P9   = CM10 * SP2
      R2P10  = CM12 * SP2
      R2P11  = CM13 * SP2
      R2P12  = CM14 * SP2
      R2P13  = CM15 * SP2
      R2P14  = CM16 * SP2
      R2P15  = CM19 * SP2
      R2P16  = CM20 * SP2
      R2P17  = CM22 * SP2
      R2P    = R2P1+ R2P2+ R2P3+ R2P4+ R2P5+
     1         R2P6+ R2P7+ R2P8+ R2P9+ R2P10+
     1         R2P11+R2P12+R2P13+R2P14+R2P15+
     1         R2P16+R2P17
      R2PT   = R2P/0.91306
```

```
C Sequences for PDS R2H
C
      R2H1   = CM3 * EH5
      R2H2   = CM5 * EH5
      R2H3   = CM1 * EH2
      R2H4   = CM2 * EH2
      R2H5   = CM8 * EH5
      R2H6   = CM9 * EH5
      R2H7   = CM20 * EH6
      R2H8   = CM6 * EH2
      R2H    = R2H1+ R2H2+ R2H3+ R2H4+ R2H5+
     1         R2H6+ R2H7+ R2H8
      R2HT   = R2H/0.89748
C
C Sequences for PDS R6D
C
      R6D1   = CM4
      R6D2   = CM11
      R6D3   = CM21
      R6D4   = CM24
      R6D5   = CM29
C
      R6D6   = FSCAW * PB1 * XLC8
C
      R6D7A6 = W1ATA6 * OL1A6 * OC1
      R6D7B5 = W1ATB5 * OL1B5 * OC1
      R6D7B6 = W1ATB6 * OL1B6 * OC1
      R6D7C1 = W1ATC1 * OL1C1 * OC1
      R6D7C5 = W1ATC5 * OL1C5 * OC1
      R6D7C6 = W1ATC6 * OL1C6 * OC1
      R6D7R  = 0.00139 * OL1A1 * OC1
      R6D7   = R6D7A1+R6D7A6+R6D7B5+R6D7B6+
     1          R6D7C1+R6D7C5+R6D7C6+R6D7R
C     Note that remainder of W1A frequency is assigned to Tree A1
C
      R6D8   = W6ATA1*OR1A1+W6ATB1*OR1B1+W6ATC1*OR1C1
C
      R6D9   = CM11 * PBA
C
      R6D10A1 = FLPCAW * ( FA*X(1)/TW ) * OR1A1
      R6D10A6 = FLPCAW * ( FA*X(2)/TW ) * OR1A6
      R6D10B1 = FLPCAW * ( FB*X(3)/TW ) * OR1B1
      R6D10B5 = FLPCAW * ( FB*X(5)/TW ) * OR1B5
      R6D10B6 = FLPCAW * ( FB*X(6)/TW ) * OR1B6
      R6D10C1 = FLPCAW * ( FC*X(7)/TW ) * OR1C1
      R6D10C2 = FLPCAW * ( FC*X(8)/TW ) * OR1C2
      R6D10C5 = FLPCAW * ( FC*X(11)/TW ) * OR1C5
      R6D10C6 = FLPCAW * ( FC*X(12)/TW )   OR1C6
      R6D10   = R6D10A1+R6D10A6+R6D10B1+R6D10B5+R6D10B6+
     1           R6D10C1+R6D10C2+R6D10C5+R6D10C6
C
      R6D11 = FLOSPW * WA3BC * XLC8
C
      R6D12   = FSCAW * (R6D10/FLPCAW)
C
      R6D13 = W1A * WA1 * PB1 * OC1
C
      R6D   = R6D1+R6D2+R6D3+R6D4+R6D5+R6D5+
     1         R6D7+R6D8+R6D9+R6D10+R6D11+R6D12+R6D13
      R6DT  = R6D/0.91047
```

```
C Sequences for PDS R6P
C
      R6P1  = CM4 * SP2
      R6P2  = CM11 * SP1
      R6P3  = CM24 * SP2
      R6P4  = CM21 * SP1
      R6P5  = R6D7 * SP2
C
      R6P6  = CM29 * SP1
      R6P7  = R6D6 * SP1
      R6P8  = R6D13 * SP2
C
      R6P = R6P1+ R6P2+ R6P3+ R6P4+ R6P5+
     1        R6P6+ R6P7+ R6P8
      R6PT  = R6P/0.89456
C
C
C Sequences for PDS R6H
C
      R6H1  = CM4 * EH6
      R6H2  = CM24 * EH5
      R6H3  = R6D7 * EH5
      R6H4  = CM11 * EH1
      R6H5  = R6D11 * EH6
      R6H6  = R6D13 * EH5
C
      R6H  = R6H1+R6H2+R6H3+R6H4+R6H5+R6H6
      R6HT = R6H/0.89715
C
C     CORE MELT FREQUENCY AT POWER
      FCMPR = X(179)
      Y(1) = R2PT
      Y(2) = R2HT
      Y(3) = R6PT
      Y(4) = R6HT
      Y(5) = CMT
      Y(6) = FCMPR
      Y(7) = CMT + FCMPR
C
      RETURN
      END
C
C********** PART OF CODE BLOCK 1 **********
C
      FUNCTION TCUW(TIN,EM)
C     THIS SUBPROGRAM COMPUTES CORE UNCOVERY TIMES FOR W CASES
      TD1=TIN/24.0
      TSG=6.43*TD1**0.309
      TD2=(TIN+TSG)/24.0
      IF(TD2.GE.14.0) GOTO 10
      TCUW=TSG + 7.9 - 0.06*TD2 - 1.5/TD2
      GOTO 20
   10 TCUW=TSG + 3.4*TD2**0.26
   20 CONTINUE
      TCUW=(1.0+EM)*TCUW
      RETURN
      END
```

```
      FUNCTION T12X(TIN.XL.EM)
C     THIS SUBPROGRAM COMPUTES CORE UNCOVERY TIMES FOR X CASES
      TD=TIN/24.0
      IF(XL.EQ.1.0) GOTO 10
      T12X=3.64*TD**0.309
      GOTO 20
   10 T12X=2.33*TD**0.309
   20 CONTINUE
      T12X=(1.0+EM)*T12X
      RETURN
      END
C
C*****************************************************************************
C**************************PART OF CODE BLOCK 5*******************************
C
      FUNCTION SWAIN(T.B)
      TM = 60.0 * T
      SWAIN = EXP( B - 0.715 * ALOG(TM) )
      RETURN
      END
C*****************************************************************************
```

F.2 FORTRAN CODING FOR UNCERTAINTY ANALYSIS OF ACCIDENT INITIATION TIMES FOR RELEASE CATEGORIES

```
      SUBROUTINE SAMPLE(X,Y)
      DIMENSION X(200),Y(150)
C
C ASSIGN VARIABLES FOR TIME TO RHR INITIATION
C ( X(1) through X(12) are the time in the 12 Procedure Trees)
C
      TAI=X(13)
      TBI=X(14)
      TCI=X(15)
      EM =X(23)
      XL =X(24)
C
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE A OUTAGES
C
      TA1SS=TAI+X(1)
      TA6SS=TA1SS+X(2)
C
C THESE STATEMENTS COMPUTE RANDOM TIMES TO INITIATION IN TYPE A OUTAGES
C
      TA1S=TAI+X(1)*X(22)
      TA6S=TA1SS+X(2)*X(22)
C
C THESE STATEMENTS COMPUTE TIMES TO CORE UNCOVERY FOR AX AND AW CONDITIONS
C
      TA1W=TA1S+TCUW(TA1S,EM)
      TA6W=TA6S+TCUW(TA6S,EM)
C
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE B OUTAGES
C
      TB1SS=TBI+X(3)
      TB2SS=TB1SS+X(4)
      TB5SS=TB2SS+X(5)
      TB6SS=TB5SS+X(6)
C
C THESE STATEMENTS COMPUTE RANDOM TIMES TO INITIATION FOR TYPE B OUTAGES
C
      TB1S=TBI+X(3)*X(22)
      TB2S=TB1SS+X(4)*X(22)
      TB5S=TB2SS+X(5)*X(22)
      TB6S=TB5SS+X(6)*X(22)
C
C THESE STATEMENTS COMPUTE CORE UNCOVERY TIMES FOR BX AND BW CONDITIONS
C
      TB1W=TB1S+TCUW(TB1S,EM)
      TB2X=TB2S+T12X(TB2S,XL,EM)
      TB5W=TB5S+TCUW(TB5S,EM)
      TB6W=TB6S+TCUW(TB6S,EM)
C
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE C OUTAGES
C
      TC1SS=TCI+X(7)
      TC2SS=TC1SS+X(8)
      TC3SS=TC2SS+X(9)
      TC4SS=TC3SS+X(10)
      TC5SS=TC4SS+X(11)
      TC6SS=TC5SS+X(12)
C
C THESE STATEMENTS COMPUTE RANDOM TIMES TO INITIATION FOR TYPE C OUTAGES
C
      TC1S=TCI+X(7)*X(22)
      TC2S=TC1SS+X(8)*X(22)
      TC3S=TC2SS+X(9)*X(22)
      TC4S=TC3SS+X(10)*X(22)
      TC5S=TC4SS+X(11)*X(22)
      TC6S=TC5SS+X(12)*X(22)
C
```

```
C THESE STATEMENTS COMPUTE CORE UNCOVERY TIMES FOR TYPE CX AND CW CONDITIONS
C
      TC1W=TC1S+TCUW(TC1S,EM)
      TC2W=TC2S+TCUW(TC2S,EM)
      TC3X=TC3S+T12X(TC3S,XL,EM)
      TC3W=TC3S+TCUW(TC3S,EM)
      TC4X=TC4S+T12X(TC4S,XL,EM)
      TC5W=TC5S+TCUW(TC5S,EM)
      TC6W=TC6S+TCUW(TC6S,EM)
C
C Output times from 100% Power to accident initiation for each tree.
C
      Y(1) = TA1S
      Y(2) = TA6S
      Y(3) = TB1S
      Y(4) = TB2S
      Y(5) = TB5S
      Y(6) = TB6S
      Y(7) = TC1S
      Y(8) = TC2S
      Y(9) = TC3S
      Y(10) = TC4S
      Y(11) = TC5S
      Y(12) = TC6S
C
C Output times from 100% Power to core damage for each tree.
C
C (Note that for time to core damage, Tree C3 is assumed to be a X-case)
C
      Y(13) = TA1W
      Y(14) = TA6W
      Y(15) = TB1W
      Y(16) = TB2X
      Y(17) = TB5W
      Y(18) = TB6W
      Y(19) = TC1W
      Y(20) = TC2W
      Y(21) = TC3X
      Y(22) = TC4X
      Y(23) = TC5W
      Y(24) = TC6W
C
C THESE STATEMENTS CALCULATE "TIME AVAILABLE FOR ACTION" FOR EACH TREE.
C [ = (Time to Core Uncovery) - (Time to accident initiation) ]
C
      TAAA1 = TA1W - TA1S
      TAAA6 = TA6W - TA6S
      TAAB1 = TB1W - TB1S
      TAAB2 = TB2X - TB2S
      TAAB5 = TB5W - TB5S
      TAAB6 = TB6W - TB6S
      TAAC1 = TC1W - TC1S
      TAAC2 = TC2W - TC2S
      TAAC3 = TC3X - TC3S
      TAAC4 = TC4X - TC4S
      TAAC5 = TC5W - TC5S
      TAAC6 = TC6W - TC6S
C
C Output "time available for action" for each tree.
C
      Y(25) = TAAA1
      Y(26) = TAAA6
      Y(27) = TAAB1
      Y(28) = TAAB2
      Y(29) = TAAB5
      Y(30) = TAAB6
```

```
      Y(31) = TAAC1
      Y(32) = TAAC2
      Y(33) = TAAC3
      Y(34) = TAAC4
      Y(35) = TAAC5
      Y(36) = TAAC6
C
C Calculate PDS time to accident inititiation.
C
C     IF(X(16).EQ.1.0)R2DAI=TA1S
C
      IF(X(17).EQ.1.0)R2PAI = TA1S
      IF(X(17).EQ.2.0)R2PAI = TA6S
      IF(X(17).EQ.3.0)R2PAI = TB1S
      IF(X(17).EQ.4.0)R2PAI = TB2S
      IF(X(17).EQ.5.0)R2PAI = TB5S
      IF(X(17).EQ.10.0)R2PAI = TC4S
      IF(X(17).EQ.11.0)R2PAI = TC5S
      IF(X(17).EQ.12.0)R2PAI = TC6S
C
      IF(X(18).EQ.1.0)R2HAI = TA1S
      IF(X(18).EQ.2.0)R2HAI = TA6S
      IF(X(18).EQ.3.0)R2HAI = TB1S
      IF(X(18).EQ.4.0)R2HAI = TB2S
      IF(X(18).EQ.5.0)R2HAI = TB5S
      IF(X(18).EQ.10.0)R2HAI = TC4S
      IF(X(18).EQ.11.0)R2HAI = TC5S
      IF(X(18).EQ.12.0)R2HAI = TC6S
C
C     IF(X(19).EQ.1.0)R6DAI = TA1S
C
      IF(X(20).EQ.1.0)R6PAI = TA1S
      IF(X(20).EQ.2.0)R6PAI = TA6S
      IF(X(20).EQ.3.0)R6PAI = TB1S
      IF(X(20).EQ.5.0)R6PAI = TB5S
      IF(X(20).EQ.7.0)R6PAI = TC1S
      IF(X(20).EQ.8.0)R6PAI = TC2S
      IF(X(20).EQ.11.0)R6PAI = TC5S
      IF(X(20).EQ.12.0)R6PAI = TC6S
C
      IF(X(21).EQ.1.0)R6HAI = TA1S
      IF(X(21).EQ.2.0)R6HAI = TA6S
      IF(X(21).EQ.3.0)R6HAI = TB1S
      IF(X(21).EQ.5.0)R6HAI = TB5S
      IF(X(21).EQ.11.0)R6HAI = TC5S
      IF(X(21).EQ.12.0)R6HAI = TC6S
C
C Output "time to accident initiation" for four plant damage states.
C
      Y(37) = R2PAI
      Y(38) = R2HAI
      Y(39) = R6PAI
      Y(40) = R6HAI
C
C Calculate PDS time to core damage.
C
C     IF(X(16).EQ.1.0)R2DCD=TA1W
C
      IF(X(17).EQ.1.0)R2PCD = TA1W
      IF(X(17).EQ.2.0)R2PCD = TA6W
      IF(X(17).EQ.3.0)R2PCD = TB1W
      IF(X(17).EQ.4.0)R2PCD = TB2X
      IF(X(17).EQ.5.0)R2PCD = TB5W
      IF(X(17).EQ.10.0)R2PCD = TC4X
      IF(X(17).EQ.11.0)R2PCD = TC5W
      IF(X(17).EQ.12.0)R2PCD = TC6W
```

```
      SUBROUTINE SAMPLE(X,Y)
      DIMENSION X(200),Y(150)
C
C ASSIGN VARIABLES FOR TIME TO RHR INITIATION
C ( X(1) through X(12) are the time in the 12 Procedure Trees)
C
      TAI=X(13)
      TBI=X(14)
      TCI=X(15)
      EM =X(23)
      XL =X(24)
C
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE A OUTAGES
C
      TA1SS=TAI+X(1)
      TA6SS=TA1SS+X(2)
C
C THESE STATEMENTS COMPUTE RANDOM TIMES TO INITIATION IN TYPE A OUTAGES
C
      TA1S=TAI+X(1)*X(22)
      TA6S=TA1SS+X(2)*X(22)
C
C THESE STATEMENTS COMPUTE TIMES TO CORE UNCOVERY FOR AX AND AW CONDITIONS
C
      TA1W=TA1S+TCUW(TA1S,EM)
      TA6W=TA6S+TCUW(TA6S,EM)
C
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE B OUTAGES
C
      TB1SS=TBI+X(3)
      TB2SS=TB1SS+X(4)
      TB5SS=TB2SS+X(5)
      TB6SS=TB5SS+X(6)
C
C THESE STATEMENTS COMPUTE RANDOM TIMES TO INITIATION FOR TYPE B OUTAGES
C
      TB1S=TBI+X(3)*X(22)
      TB2S=TB1SS+X(4)*X(22)
      TB5S=TB2SS+X(5)*X(22)
      TB6S=TB5SS+X(6)*X(22)
C
C THESE STATEMENTS COMPUTE CORE UNCOVERY TIMES FOR BX AND BW CONDITIONS
C
      TB1W=TB1S+TCUW(TB1S,EM)
      TB2X=TB2S+T12X(TB2S,XL,EM)
      TB5W=TB5S+TCUW(TB5S,EM)
      TB6W=TB6S+TCUW(TB6S,EM)
C
C THESE STATEMENTS COMPUTE TOTAL DURATIONS OF TYPE C OUTAGES
C
      TC1SS=TCI+X(7)
      TC2SS=TC1SS+X(8)
      TC3SS=TC2SS+X(9)
      TC4SS=TC3SS+X(10)
      TC5SS=TC4SS+X(11)
      TC6SS=TC5SS+X(12)
C
C THESE STATEMENTS COMPUTE RANDOM TIMES TO INITIATION FOR TYPE C OUTAGES
C
      TC1S=TCI+X(7)*X(22)
      TC2S=TC1SS+X(8)*X(22)
      TC3S=TC2SS+X(9)*X(22)
      TC4S=TC3SS+X(10)*X(22)
      TC5S=TC4SS+X(11)*X(22)
      TC6S=TC5SS+X(12)*X(22)
C
```

```
C THESE STATEMENTS COMPUTE CORE UNCOVERY TIMES FOR TYPE CX AND CW CONDITIONS
C
      TC1W=TC1S+TCUW(TC1S,EM)
      TC2W=TC2S+TCUW(TC2S,EM)
      TC3X=TC3S+T12X(TC3S,XL,EM)
      TC3W=TC3S+TCUW(TC3S,EM)
      TC4X=TC4S+T12X(TC4S,XL,EM)
      TC5W=TC5S+TCUW(TC5S,EM)
      TC6W=TC6S+TCUW(TC6S,EM)
C
C Output times from 100% Power to accident initiation for each tree.
C
      Y(1) = TA1S
      Y(2) = TA6S
      Y(3) = TB1S
      Y(4) = TB2S
      Y(5) = TB5S
      Y(6) = TB6S
      Y(7) = TC1S
      Y(8) = TC2S
      Y(9) = TC3S
      Y(10) = TC4S
      Y(11) = TC5S
      Y(12) = TC6S
C
C Output times from 100% Power to core damage for each tree.
C
C (Note that for time to core damage, Tree C3 is assumed to be a X-case)
C
      Y(13) = TA1W
      Y(14) = TA6W
      Y(15) = TB1W
      Y(16) = TB2X
      Y(17) = TB5W
      Y(18) = TB6W
      Y(19) = TC1W
      Y(20) = TC2W
      Y(21) = TC3X
      Y(22) = TC4X
      Y(23) = TC5W
      Y(24) = TC6W
C
C THESE STATEMENTS CALCULATE "TIME AVAILABLE FOR ACTION" FOR EACH TREE.
C [ = (Time to Core Uncovery) - (Time to accident initiation) ]
C
      TAAA1 = TA1W - TA1S
      TAAA6 = TA6W - TA6S
      TAAB1 = TB1W - TB1S
      TAAB2 = TB2X - TB2S
      TAAB5 = TB5W - TB5S
      TAAB6 = TB6W - TB6S
      TAAC1 = TC1W - TC1S
      TAAC2 = TC2W - TC2S
      TAAC3 = TC3X - TC3S
      TAAC4 = TC4X - TC4S
      TAAC5 = TC5W - .C5S
      TAAC6 = TC6W - TC6S
C
C ...put "time available for action" for each tree.
C
      Y(25) = TAAA1
      Y(26) = TAAA6
      Y(27) = TAAB1
      Y(28) = TAAB2
      Y(29) = TAAB5
      Y(30) = TAAB6
```

```
      Y(31) = TAAC1
      Y(32) = TAAC2
      Y(33) = TAAC3
      Y(34) = TAAC4
      Y(35) = TAAC5
      Y(36) = TAAC6
C
C Calculate PDS time to accident inititiation.
C
C     IF(X(16).EQ.1.0)R2DAI=TA1S
C
      IF(X(17).EQ.1.0)R2PAI = TA1S
      IF(X(17).EQ.2.0)R2PAI = TA6S
      IF(X(17).EQ.3.0)R2PAI = TB1S
      IF(X(17).EQ.4.0)R2PAI = TB2S
      IF(X(17).EQ.5.0)R2PAI = TB5S
      IF(X(17).EQ.10.0)R2PAI = TC4S
      IF(X(17).EQ.11.0)R2PAI = TC5S
      IF(X(17).EQ.12.0)R2PAI = TC6S
C
      IF(X(18).EQ.1.0)R2HAI = TA1S
      IF(X(18).EQ.2.0)R2HAI = TA6S
      IF(X(18).EQ.3.0)R2HAI = TB1S
      IF(X(18).EQ.4.0)R2HAI = TB2S
      IF(X(18).EQ.5.0)R2HAI = TB5S
      IF(X(18).EQ.10.0)R2HAI = TC4S
      IF(X(18).EQ.11.0)R2HAI = TC5S
      IF(X(18).EQ.12.0)R2HAI = TC6S
C
C     IF(X(19).EQ.1.0)R6DAI = TA1S
C
      IF(X(20).EQ.1.0)R6PAI = TA1S
      IF(X(20).EQ.2.0)R6PAI = TA6S
      IF(X(20).EQ.3.0)R6PAI = TB1S
      IF(X(20).EQ.5.0)R6PAI = TB5S
      IF(X(20).EQ.7.0)R6PAI = TC1S
      IF(X(20).EQ.8.0)R6PAI = TC2S
      IF(X(20).EQ.11.0)R6PAI = TC5S
      IF(X(20).EQ.12.0)R6PAI = TC6S
C
      IF(X(21).EQ.1.0)R6HAI = TA1S
      IF(X(21).EQ.2.0)R6HAI = TA6S
      IF(X(21).EQ.3.0)R6HAI = TB1S
      IF(X(21).EQ.5.0)R6HAI = TB5S
      IF(X(21).EQ.11.0)R6HAI = TC5S
      IF(X(21).EQ.12.0)R6HAI = TC6S
C
C Output "time to accident initiation" for four plant damage states.
C
      Y(37) = R2PAI
      Y(38) = R2HAI
      Y(39) = R6PAI
      Y(40) = R6HAI
C
C Calculate PDS time to core damage.
C
C     IF(X(16).EQ.1.0)R2DCD=TA1W
C
      IF(X(17).EQ.1.0)R2PCD = TA1W
      IF(X(17).EQ.2.0)R2PCD = TA6W
      IF(X(17).EQ.3.0)R2PCD = TB1W
      IF(X(17).EQ.4.0)R2PCD = TB2X
      IF(X(17).EQ.5.0)R2PCD = TB5W
      IF(X(17).EQ.10.0)R2PCD = TC4X
      IF(X(17).EQ.11.0)R2PCD = TC5W
      IF(X(17).EQ.12.0)R2PCD = TC6W
```

F.3 INPUT DISTRIBUTIONS USED IN UNCERTAINTY ANALYSIS

```
' SEABROOK SHUTDOWN STUDY, FINAL STADIC4 INPUT FILE from 19 May 88
 $MAINDAT IN=179,NOVAR=7,IMAX=3000,JMAX=10000,NTABLE=41,IRSEED=212834385
  DBASE=F,MORE=F, $END
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=41.0,222.0,1116.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 1, time in A1
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=12.0,24.0,36.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 2, time in A6
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=6.0,27.0,83.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 3, time in B1
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=537.0,922.0,1670.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 4, time in B2
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=30.0,90.0,252.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 5, time in B5
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=12.0,24.0,36.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 6, time in B6
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=23.0,46.0,107.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 7, time in C1
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=9.0,49.0,73.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 8, time in C2
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=74.0,160.0,253.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 9, time in C3
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=740.0,1429.0,2244.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 10, time in C4
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=24.0,184.0,430.0
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 11, time in C5
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=48.0,72.0,96.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 12, time in C6
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=18.0,20.0,37.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 13, RHR time, A
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=9.0,18.0,37.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 14, RHR time, B
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=36.0,54.0,85.0,
                           ORDIN=.1,.8,.1,  DIST=T, $END  TABLE 15, RHR time, C
 $TABLE NUMPT=4,INTPOL=0,ABSCIS=3.0,4.0,10.0,11.0,
                ORDIN=.1062,.15,.702,.0418,  DIST=T, $END  TABLE 16, not used
 $TABLE NUMPT=8,INTPOL=0,ABSCIS=1.0,2.0,3.0,4.0,5.0,10.0,11.0,12.0,
    ORDIN=.065,.014,.023,.229,.021,.579,.064,.005  DIST=T, $END TBL 17, R2PCD
 $TABLE NUMPT=8,INTPOL=0,ABSCIS=1.0,2.0,3.0,4.0,5.0,10.0,11.0,12.0,
    ORDIN=.227,.049,.078,.123,.074,.210,.223,.016  DIST=T, $END #18, R2HCD
 $TABLE NUMPT=8,INTPOL=0,ABSCIS=1.0,2.0,3.0,5.0,6.0,7.0,11.0,12.0,
    ORDIN=.067,.250,.063,.036,.027,.37,.11,.077, DIST=T, $END TBL 19, not used
 $TABLE NUMPT=8,INTPOL=0,ABSCIS=1.0,2.0,3.0,5.0,7.0,8.0,11.0,12.0,
    ORDIN=.525,.025,.168,.029,.017,.005,.221,.010  DIST=T, $END TBL 20, R6PCD
 $TABLE NUMPT=6,INTPOL=0,ABSCIS=1.0,2.0,3.0,5.0,11.0,12.0,
    ORDIN=.493,.026,.186,.039,.248,.008   DIST=T, $END TBL 21, R6HCD
 $TABLE NUMPT=2,INTPOL=0,ABSCIS=0.0,1.0,
                           ORDIN=0.0,1.0,DIST=F, $END TABLE 22, uniform fr. cmp.
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=-0.10,0.0,0.20,
                           ORDIN=.1,.8,.1,     DIST=T, $END         TABLE 23, EM
 $TABLE NUMPT=2,INTPOL=0,ABSCIS=1.0,2.0,
                           ORDIN=.034,.966     DIST=T, $END         TABLE 24, XL
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=1.0,2.8,11.0,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 25
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=.125,.25,2.4,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 26
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=.67,.83,1.0,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 27
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=.033,.115,.165,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 28
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=.1,.3,.5,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 29
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=.0295,.103,.148,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 30
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=.0231,.0577,.115,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 31
 $TABLE NUMPT=3,INTPOL=0,ABSCIS=.017,.034,.068,
```

```
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 32
$TABLE NUMPT=3,INTPOL=0,ABSCIS=.0077,.0019,.00048,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 33
$TABLE NUMPT=11,INTPOL=0,
    ABSCIS=.27,.242,.209,.135,.164,.145,
         .126,.105,.081,.048,.02,
    ORDIN=.05,.1,.1,.1,.1,.1,.1,.1,.1,.1,.05,   DIST=T, $END       TABLE 34
$TABLE NUMPT=3,INTPOL=0,ABSCIS=.173,.069,.017,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 35
$TABLE NUMPT=3,INTPOL=0,ABSCIS=1.0,1.0,0.25,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 36
$TABLE NUMPT=3,INTPOL=0,ABSCIS=1.0,2.0,3.0,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 37
$TABLE NUMPT=3,INTPOL=0,ABSCIS=12.0,24.0,36.0,
                           ORDIN=.1,.8,.1,     DIST=T, $END            TABLE 38
$TABLE NUMPT=20,INTPOL=0,ABSCIS=1.47E-7,4.07E-7,5.16E-7,1.10E-6,
       1.33E-6,1.60E-6,2.35E-6,2.65E-6,3.52E-6,5.29E-6,5.40E-6,
       6.15E-6,8.96E-6,1.08E-5,1.41E-5,1.67E-5,1.99E-5,3.57E-5
       4.76E-5,9.83E-5,
                           ORDIN=.05,.05,.05,.05,.05,.05,.05,.05,
       .05,.05,.05,.05,.05,.05,.05,.05,.05,.05,.05,.05,
                                               DIST=T, $END            TABLE 39
$TABLE NUMPT=20,INTPOL=0,ABSCIS=4.98E-8,1.38E-7,1.76E-7,3.61E-7,
       4.43E-7,6.33E-7,7.92E-7,9.10E-7,1.19E-6,1.86E-6,1.97E-6,
       2.15E-6,3.28E-6,4.22E-6,5.01E-6,6.45E-6,8.23E-6,1.34E-5
       2.12E-5,4.47E-5,
                           ORDIN=.05,.05,.05,.05,.05,.05,.05,.05,
       .05,.05,.05,.05,.05,.05,.05,.05,.05,.05,.05,.05,
                                               DIST=T, $END            TABLE 40
$TABLE NUMPT=20,INTPOL=0,ABSCIS=4.40E-10,2.29E-9,7.26E-9,1.50E-8,
       2.87E-8,4.78E-8,7.66E-8,1.20E-7,1.56E-7,2.38E-7,4.00E-7,
       5.20E-7,7.68E-7,9.26E-7,1.21E-6,1.91E-6,3.07E-6,5.00E-6
       7.66E-6,2.30E-5,
                           ORDIN=.05,.05,.05,.05,.05,.05,.05,.05,
       .05,.05,.05,.05,.05,.05,.05,.05,.05,.05,.05,.05,
                                               DIST=T, $END            TABLE 41
$INVAR ITABLE=1,ITYPE=5, $END    X(1), time in A1
$INVAR ITABLE=2,ITYPE=5, $END    X(2), time in A6
$INVAR ITABLE=3,ITYPE=5, $END    X(3), time in B1
$INVAR ITABLE=4,ITYPE=5, $END    X(4), time in B2
$INVAR ITABLE=5,ITYPE=5, $END    X(5), time in B5
$INVAR ITABLE=6,ITYPE=5, $END    X(6), time in B6
$INVAR ITABLE=7,ITYPE=5, $END    X(7), time in C1
$INVAR ITABLE=8,ITYPE=5, $END    X(8), time in C2
$INVAR ITABLE=9,ITYPE=5, $END    X(9), time in C3
$INVAR ITABLE=10,ITYPE=5, $END    X(10), time in C4
$INVAR ITABLE=11,ITYPE=5, $END    X(11), time in C5
$INVAR ITABLE=12,ITYPE=5, $END    X(12), time in C6
$INVAR ITABLE=13,ITYPE=5, $END    X(13), RHR initiation time, A
$INVAR ITABLE=14,ITYPE=5, $END    X(14), RHR initiation time, B
$INVAR ITABLE=15,ITYPE=5, $END    X(15), RHR initiation time, C
$INVAR ITABLE=16,ITYPE=5, $END    X(16), binning for R2D
$INVAR ITABLE=17,ITYPE=5, $END    X(17), binning for R2P
$INVAR ITABLE=18,ITYPE=5, $END    X(18), binning for R2H
$INVAR ITABLE=19,ITYPE=5, $END    X(19), binning for R6D
$INVAR ITABLE=20,ITYPE=5, $END    X(20), binning for R6P
$INVAR ITABLE=21,ITYPE=5, $END    X(21), binning for R6H
$INVAR ITABLE=22,ITYPE=4, $END    X(22), uniform for fraction completed
$INVAR ITABLE=23,ITYPE=5, $END    X(23), EM, T/H modeling uncertainty
$INVAR ITABLE=24,ITYPE=5, $END    X(24), XL, level in vessel - X cond.
$INVAR ITABLE=25,ITYPE=5, $END    X(25), Frequency of type A outage, FA
$INVAR ITABLE=26,ITYPE=5, $END    X(26), Frequency of type B outage, FB
$INVAR ITABLE=27,ITYPE=5, $END    X(27), Frequency of type C outage, FC
$INVAR ITYPE=2,PARAM1=2.22E-5,PARAM2=5.72, $END  X(28) FRH1R
$INVAR ITYPE=2,PARAM1=1.45E-3,PARAM2=5.06, $END  X(29) ZIPMOS
$INVAR ITYPE=2,PARAM1=4.74E-2,PARAM2=3.90, $END  X(30) ZBPDHS
```

```
$INVAR ITYPE=2,PARAM1=2.68E-1,PARAM2=1.50, $END  X(31) ZBPDHR
$INVAR ITYPE=2,PARAM1=3.00E-3,PARAM2=3.00, $END  X(32) FOP1
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(33) FOP2
$INVAR ITABLE=28,ITYPE=5, $END                   X(34) from TABLE 28, FM1W
$INVAR ITYPE=2,PARAM1=3.05E-3,PARAM2=3.90, $END  X(35) ZIVMOD
$INVAR ITYPE=2,PARAM1=1.50E-1,PARAM2=5.00, $END  X(36) FNR
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(37) FNRP
$INVAR ITYPE=2,PARAM1=4.10E-2,PARAM2=5.70, $END  X(38) FIRAUX
$INVAR ITYPE=2,PARAM1=1.40E-2,PARAM2=12.3, $END  X(39) FTBSD
$INVAR ITYPE=2,PARAM1=1.75E-1,PARAM2=1.70, $END  X(40) FSGR
$INVAR ITYPE=2,PARAM1=9.30E-3,PARAM2=7.10, $END  X(41) FTNL
$INVAR ITYPE=2,PARAM1=7.70E-2,PARAM2=8.20, $END  X(42) Q1TG
$INVAR ITABLE=29,ITYPE=5, $END                   X(43) from TABLE 29, FHS
$INVAR ITYPE=2,PARAM1=9.30E-3,PARAM2=7.10, $END  X(44) FP1A
$INVAR ITYPE=2,PARAM1=4.90E-2,PARAM2=10.0, $END  X(45) FP1AS
$INVAR ITYPE=2,PARAM1=4.80E-1,PARAM2=2.30, $END  X(46) Q2TG
$INVAR ITYPE=2,PARAM1=3.00E-2,PARAM2=3.30, $END  X(47) FTBGS
$INVAR ITYPE=2,PARAM1=1.92E-5,PARAM2=5.70, $END  X(48) FPR
$INVAR ITYPE=2,PARAM1=2.02E-1,PARAM2=1.60, $END  X(49) ZMGNBD
$INVAR ITABLE=30,ITYPE=5, $END                   X(50) from TABLF 30, FM1X
$INVAR ITYPE=2,PARAM1=9.77E-3,PARAM2=8.70, $END  X(51) ZBPCWR
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=10.0, $END  X(52) ZBPCWS
$INVAR ITYPE=2,PARAM1=4.69E-4,PARAM2=5.70, $END  X(53) FPA
$INVAR ITYPE=2,PARAM1=2.20E-4,PARAM2=10.0, $END  X(54) FPC
$INVAR ITABLE=31,ITYPE=5, $END                   X(55) from TABLE 31, FM2W
$INVAR ITYPE=2,PARAM1=2.29E-3,PARAM2=5.10, $END  X(56) BB
$INVAR ITYPE=2,PARAM1=6.01E-4,PARAM2=4.40, $END  X(57) FPCC2A
$INVAR ITYPE=2,PARAM1=6.97E-2,PARAM2=2.00, $END  X(58) ZBPSWR
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=3.00, $END  X(59) FOP1CT
$INVAR ITYPE=2,PARAM1=4.48E-2,PARAM2=1.90, $END  X(60) FCTA
$INVAR ITYPE=2,PARAM1=7.10E-2,PARAM2=6.45, $END  X(61) FLOSPP
$INVAR ITYPE=2,PARAM1=3.38E-3,PARAM2=10.0, $END  X(62) FLOSPV
$INVAR ITYPE=1,PARAM1=-6.29,PARAM2=3.42, $END    X(63) B (for SWAIN)
$INVAR ITYPE=2,PARAM1=5.10E-4,PARAM2=4.70, $END  X(64) XNC1
$INVAR ITYPE=2,PARAM1=1.60E-3,PARAM2=4.70, $END  X(65) XNC3
$INVAR ITYPE=2,PARAM1=2.40E-4,PARAM2=4.70, $END  X(66) XLIHW1
$INVAR ITYPE=2,PARAM1=3.10E-4,PARAM2=4.70, $END  X(67) XLIHW2
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=5.00, $END  X(68) XLIOP1
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(69) XLINR1
$INVAR ITYPE=2,PARAM1=1.50E-1,PARAM2=5.00, $END  X(70) XLINR2
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(71) CC1OP1
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=5.00, $END  X(72) CC1OP2
$INVAR ITYPE=2,PARAM1=1.50E-3,PARAM2=4.70, $END  X(73) PUHW1
$INVAR ITYPE=2,PARAM1=2.30E-3,PARAM2=4.70, $END  X(74) PUHW2
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=3.00, $END  X(75) PUOP1
$INVAR ITYPE=2,PARAM1=3.00E-3,PARAM2=3.00, $END  X(76) XLMOP1
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=3.00, $END  X(77) XLMOP2
$INVAR ITYPE=2,PARAM1=1.50E-1,PARAM2=5.00, $END  X(78) XLMNR1
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(79) TL1
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(80) XISOP1
$INVAR ITYPE=2,PARAM1=1.50E-1,PARAM2=5.00, $END  X(81) XISOP2
$INVAR ITYPE=2,PARAM1=6.40E-2,PARAM2=4.70, $END  X(82) RV1PT
$INVAR ITYPE=2,PARAM1=2.20E-2,PARAM2=21.8, $END  X(83) RV1B
$INVAR ITYPE=2,PARAM1=2.80E-2,PARAM2=5.00, $END  X(84) RV1OP3
$INVAR ITYPE=2,PARAM1=6.55E-6,PARAM2=4.70, $END  X(85) SALPT1
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(86) SAOP1
$INVAR ITYPE=2,PARAM1=1.00E-1,PARAM2=5.00, $END  X(87) SAOP2
$INVAR ITYPE=2,PARAM1=2.00E-1,PARAM2=5.00, $END  X(88) SANR1
$INVAR ITYPE=2,PARAM1=2.00E-3,PARAM2=3.00, $END  X(89) SAOP3
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(90) SANR2
$INVAR ITYPE=2,PARAM1=1.40E-1,PARAM2=5.00, $END  X(91) SANR3
$INVAR ITYPE=2,PARAM1=6.55E-5,PARAM2=4.70, $END  X(92) SALPT2
$INVAR ITYPE=2,PARAM1=2.00E-7,PARAM2=42.0, $END  X(93) SALPB
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(94) CT1OP1
$INVAR ITYPE=2,PARAM1=5.00E-3,PARAM2=3.00, $END  X(95) CT1OP2
$INVAR ITYPE=2,PARAM1=4.00E-3,PARAM2=3.00, $END  X(96) CT1OP3
```

```
$INVAR ITYPE=2,PARAM1=2.00E-1,PARAM2=5.00, $END  X(97) CT1NR2
$INVAR ITYPE=2,PARAM1=2.00E-1,PARAM2=5.00, $END  X(98) CT1NR3
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(99) TV1OP1
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(100) TV1OP2
$INVAR ITYPE=2,PARAM1=1.24E-5,PARAM2=3.10, $END  X(101) ZITRLR
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=3.00, $END  X(102) XLMOP3
$INVAR ITYPE=2,PARAM1=1.40E-1,PARAM2=5.00, $END  X(103) XLMNR2
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(104) XLMNR3
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(105) DR1OP1
$INVAR ITYPE=2,PARAM1=1.50E-1,PARAM2=5.00, $END  X(106) DR1NR1
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(107) RF1OP1
$INVAR ITYPE=2,PARAM1=1.50E-1,PARAM2=5.00, $END  X(108) RF1NR1
$INVAR ITABLE=32,ITYPE=5, $END                   X(109) from TABLE 32, DM1
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(110) CD1OP1
$INVAR ITYPE=2,PARAM1=1.50E 1,PARAM2=5.00, $END  X(111) CD1OPP
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=3.00, $END  X(112) CD1OP2
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(113) BR1
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=3.00, $END  X(114) XLCO1
$INVAR ITYPE=2,PARAM1=1.40E-1,PARAM2=5.00, $END  X(115) XLCO2
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=3.00, $END  X(116) XLCNR
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(117) XLCUCF
$INVAR ITYPE=2,PARAM1=3.00E-2,PARAM2=5.00, $END  X(118) XLCORT
$INVAR ITYPE=2,PARAM1=1.50E-1,PARAM2=5.00, $END  X(119) XLCOBT
$INVAR ITABLE=33,ITYPE=5, $END                   X(120) from TABLE 33, XLCRW
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(121) XLCOPC
$INVAR ITYPE=2,PARAM1=3.20E-6,PARAM2=5.00, $END  X(122) XLCFD1
$INVAR ITYPE=2,PARAM1=3.80E-5,PARAM2=5.00, $END  X(123) XLCFD2
$INVAR ITYPE=2,PARAM1=5.00E-3,PARAM2=3.00, $END  X(124) XLCOFD
$INVAR ITYPE=2,PARAM1=1.58E-4,PARAM2=2.90, $END  X(125) XLCSLH
$INVAR ITYPE=2,PARAM1=2.40E-3,PARAM2=6.70, $END  X(126) XLCS1B
$INVAR ITABLE=30,ITYPE=5, $END                   X(127) from TABLE 30, FMIX
$INVAR ITYPE=2,PARAM1=3.41E-3,PARAM2=3.00, $END  X(128) XLCPV
$INVAR ITYPE=2,PARAM1=2.20E-2,PARAM2=21.8, $END  X(129) XLCPVB
$INVAR ITYPE=2,PARAM1=3.98E-2,PARAM2=2.70, $END  X(130) XLCFW2
$INVAR ITYPE=2,PARAM1=4.83E-3,PARAM2=2.80, $END  X(131) XLCFW5
$INVAR ITYPE=2,PARAM1=1.22E-2,PARAM2=2.90, $END  X(132) XLCSFP
$INVAR ITYPE=2,PARAM1=1.17E-3,PARAM2=3.30, $END  X(133) XLCAOV
$INVAR ITYPE=2,PARAM1=1.20E-2,PARAM2=3.10, $END  X(134) XLCNR2
$INVAR ITABLE=39,ITYPE=5, $END                   X(135) from TABLE  39, SSBCW
$INVAR ITABLE=40,ITYPE=5, $END                   X(136) from TABLE  40, SSBOX
$INVAR ITABLE=41,ITYPE=5, $END                   X(137) from TABLE  41, SLL
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(138) OPICS for L5
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(139) NRICS for L5
$INVAR ITYPE=2,PARAM1=1.56E-4,PARAM2=6.80, $END  X(140) GABER for ac pwr rec
$INVAR ITYPE=2,PARAM1=3.60E-7,PARAM2=16.5, $END  X(141) PCC1A
$INVAR ITYPE=2,PARAM1=6.63E-4,PARAM2=4.00, $END  X(142) PCC2B
$INVAR ITYPE=2,PARAM1=9.55E-4,PARAM2=2.40, $END  X(143) SWABP
$INVAR ITYPE=2,PARAM1=1.81E-2,PARAM2=1.80, $END  X(144) SWAP
$INVAR ITYPE=2,PARAM1=1.52E-3,PARAM2=5.00, $END  X(145) SWA
$INVAR ITYPE=2,PARAM1=4.62E-4,PARAM2=5.70, $END  X(146) SWAA
$INVAR ITYPE=2,PARAM1=4.48E-2,PARAM2=1.90, $END  X(147) SWCTA
$INVAR ITYPE=2,PARAM1=1.00E-3,PARAM2=3.00, $END  X(148) SWOP1
$INVAR ITYPE=2,PARAM1=8.20E-4,PARAM2=3.80, $END  X(149) XLCLLL
$INVAR ITYPE=2,PARAM1=3.79E-3,PARAM2=3.20, $END  X(150) XLCSA
$INVAR ITYPE=2,PARAM1=3.18E-3,PARAM2=3.60, $END  X(151) XLCHA
$INVAR ITYPE=2,PARAM1=3.46E-7,PARAM2=4.10, $END  X(152) XLSCV
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(153) XLSNR
$INVAR ITYPE=2,PARAM1=1.00E-4,PARAM2=30.0, $END  X(154) OC1OP1
$INVAR ITYPE=2,PARAM1=5.00E-4,PARAM2=10.0, $END  X(155) OC1OP2
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(156) OC1NR
$INVAR ITYPE=2,PARAM1=1.75E-2,PARAM2=3.00, $END  X(157) OC1VC1
$INVAR ITYPE=2,PARAM1=3.00E-3,PARAM2=3.00, $END  X(158) XIROP1
$INVAR ITYPE=2,PARAM1=3.10E-3,PARAM2=3.90, $END  X(159) XIRHW1
$INVAR ITYPE=2,PARAM1=2.00E-2,PARAM2=3.00, $END  X(160) SPOP1
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(161) SPNR
$INVAR ITYPE=2,PARAM1=6.00E-3,PARAM2=3.00, $END  X(162) SPOUT
```

```
$INVAR ITYPE=2,PARAM1=1.50E-2,PARAM2=3.00, $END  X(163) SPOUTP
$INVAR ITABLE=36,ITYPE=5, $END                   X(164) from TABLE 36, EHF1
$INVAR ITABLE=?7,ITYPE=5, $END                   X(165) from TABLE 37, EHF2
$INVAR ITABLE=38,ITYPE=5, $END                   X(166) from TABLE 38, EHF3
$INVAR ITYPE=2,PARAM1=1.68E-3,PARAM2=6.70, $END  X(167) EHZIPM
$INVAR ITYPE=2,PARAM1=9.96E-5,PARAM2=10.0, $END  X(168) EHZIVA
$INVAR ITYPE=2,PARAM1=2.00E-2,PARAM2=3.00, $END  X(169) EHOP1
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(170) EHNR
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=3.00, $END  X(171) EHOP2
$INVAR ITYPE=2,PARAM1=1.00E-1,PARAM2=5.00, $END  X(172) EHOPEH
$INVAR ITYPE=2,PARAM1=6.00E-4,PARAM2=10.0, $END  X(173) OD1
$INVAR ITYPE=2,PARAM1=9.20E-3,PARAM2=4.90, $END  X(174) DGAB24
$INVAR ITYPE=2,PARAM1=5.80E-2,PARAM2=4.90, $END  X(175) DGA24
$INVAR ITYPE=2,PARAM1=1.00E-2,PARAM2=3.00, $END  X(176) CT2A
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(177) CT2B
$INVAR ITYPE=2,PARAM1=5.00E-2,PARAM2=5.00, $END  X(178) CT2C
$INVAR ITYPE=2,PARAM1=1.9E-4,PARAM2=3.3, $END  X(179) FCMPR
Y(1): PDS R2P TOTAL = 1.54-6
$OUTVAR ICALC=T,NUMBINS=20,SORT=F, $END
Y(2): PDS R2H TOTAL = 5.30-7
$OUTVAR $END
Y(3): PDS R6P TOTAL = 1.44-7
$OUTVAR $END
Y(4): PDS R6H TOTAL = 1.43-7
$OUTVAR $END
Y(5): SHUTDOWN CM TOTAL = 4.40-5
$OUTVAR $END
Y(6): POWER CM TOTAL = 2.47-4
$OUTVAR $END
Y(7): CM TOTAL = 2.90-4
$OUTVAR $END
```