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Reactor Safety Study Methodology Applications Program: Grand Gulf #1 BWR Power Plant

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FOREWORD

This report is the fourth in a series of four reports which present the results of analyses performed in the Reactor Safety Study Methodology Applications Program (RSSMAP). This volume describes the analysis performed for the Grand Gulf Unit 1 nuclear reactor; other volumes describe the analyses of Sequoyah Unit 1, Oconee Unit 3, and Calvert Cliffs Unit 2. The RSSMAP analyses were an attempt to use insights from the relatively detailed and elaborate Reactor Safety Study analysis to perform a meaningful plant risk analysis with minimum manpower and economic impacts. It was also desired that the study of plants with differing reactor and containment designs would broaden the class of nuclear power plants explicitly analyzed in terms of risk.

The reader should be cautioned to consider these results in their proper context. As was true of all the RSSMAP plants studied, the Grand Gulf analysis was conducted primarily with information available in the Final Safety Analysis Report (FSAR). Technical Specifications and plant procedures were not available for Grand Gulf since it is still under construction. This approach does imply some limitations in the depth of the analysis since as-built systems often differ from those depicted in FSAR drawings and FSAR analyses generally indicate more conservative criteria and guidelines than are actually required for plant response to accidents. Further, it is acknowledged that subsequent to the completion of the Grand Gulf analysis, some changes in plant design (e.g., installation of a hydrogen ignition system) may be made which will have an effect on the frequencies of the dominant accident sequences.

It should also be noted that some developments in risk assessment methodology have been employed in the Grand Gulf analysis which were not used in the earlier Sequoyah analysis. Among the most important of these involves the development of improved transient event trees and the treatment of dominant accident sequences to include complement events.

Comments on this report and the RSSMAP methodology are invited. Comments should be sent to:

Chief, Reactor Risk Branch
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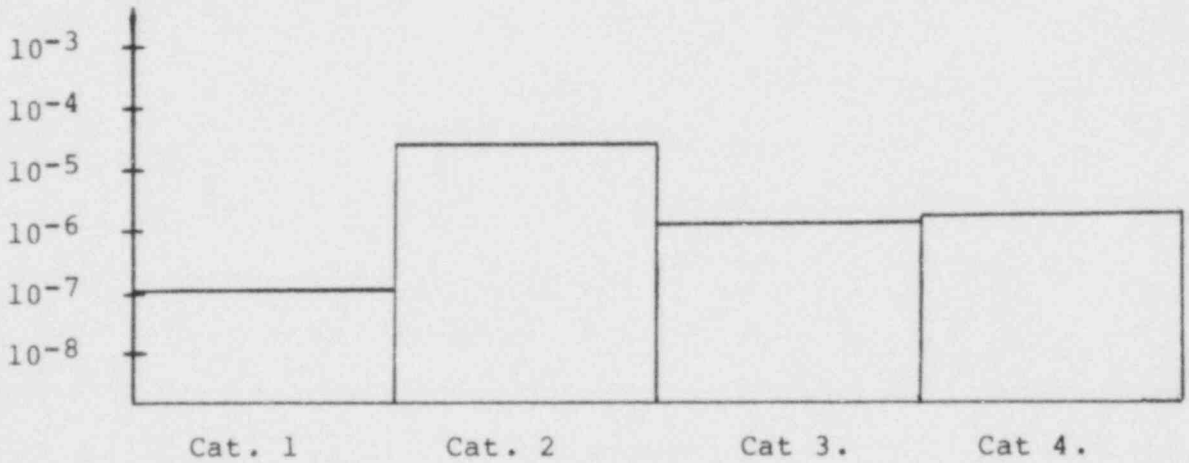
EXECUTIVE SUMMARY

This volume represents the results of the analysis of the Grand Gulf Unit 1 Nuclear Power Plant which was performed as part of the Reactor Safety Study Methodology Applications Program (RSSMAP). The RSSMAP was conducted to apply the methodology developed in the Reactor Safety Study (RSS) to an additional group of plants with the following objectives in mind: (1) identification of the risk dominating accident sequences for a broader group of reactor designs; (2) comparison of these accident sequences with those identified in the RSS; and (3) based on this comparison, identification of design differences which have a significant impact on risk.

Significant use of RSS insights and results was made for the Grand Gulf analysis. Loss of coolant accidents (LOCAs) and transients were used as initiating events. The release categories, human error, and component failure data bases were the same as those used in the RSS. The transient and LOCA event trees for Grand Gulf differ somewhat from the RSS event trees. This is due to different systems and interactions between systems at Grand Gulf. In addition, the RSSMAP transient and LOCA trees are interrelated in recognition that transient initiating events may ultimately lead to LOCA conditions. Unlike the RSS, detailed fault trees were not used to identify all possible failure modes; rather, a "survey and analysis" technique was used to identify the most likely failure modes of a system. The determination of which accident sequences result in core melt and the subsequent containment response and release was made by the MARCH and CORRAL codes

which are significantly more developed codes than those available when the RSS was performed. No consequence analysis was performed.

Results of the Grand Gulf RSSMAP analyses can be summarized in the histogram below, which depicts the total accident sequence frequency in each of the four BWR core melt categories used in the RSS.



The most significant sequences contributing to the core melt frequency and, by extension, the risk were transient initiated sequences which are followed by a loss of all long-term decay heat removal. These sequences contributed approximately 90% of the total core melt frequency at Grand Gulf.

The predicted total core melt frequency for Grand Gulf using the RSSMAP methodology is approximately the same as that predicted for Peach Bottom in the Reactor Safety Study.

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1.0 INTRODUCTION

As a part of determining the public risk due to accidents in light water reactors (LWR), the Reactor Safety Study (RSS) (Reference 1) developed a methodology for evaluating risks associated with potential accidents at nuclear power plants. A number of organizations and individuals have recommended that the methodology developed in the RSS be used on a wider basis to analyze commercial power reactor systems and to assist in making informed decisions when public risk is a consideration. Further, it has also been stated by the Nuclear Regulatory Commission (NRC)[1] that ways should be examined in which the RSS methodology can be used to improve the regulatory process. In light of this, the Division of Risk Analysis (formerly the Probabilistic Analysis Staff) of the NRC Office of Research initiated a program in October of 1975, entitled "The Reactor Safety Study Methodology Applications Program (RSSMAP)," to provide a broader foundation for applications of the RSS methodology and engineering insights into the regulatory safety review process.

The RSS addressed two reactors, the Surry and Peach Bottom plants. For those two reactors, the accident sequences that dominated risk were identified. As a further application of the RSS methodology, the RSSMAP was conducted with the following objectives: (1) identify the risk dominating accident sequences for a broader spectrum of reactor designs, (2) compare those accident sequences with those identified for the reactors studied in the RSS, and (3) based on this comparison, identify design differences between the plants which have a significant impact on risk.

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[1]See NRC Annual Report to the President, 1975.

The Reactor Safety Study Methodology Applications Program was divided into two principal tasks: systems analysis of engineered systems, and analysis of the accident processes. Sandia National Laboratories was contracted to perform the systems analysis task. This task was performed with the aid of Evaluation Associates, Inc., of Bala Cynwyd, Pennsylvania as a subcontractor. Battelle Columbus Laboratories was contracted to perform the analysis of accident processes.

The RSSMAP study includes three PWR power plant designs and one BWR plant design. These designs are significantly different from those studied in the RSS. Table 1-1 identifies the RSSMAP plants, the RSS plant used for comparison, and some key design features.

This volume documents the results for the Grand Gulf #1 plant. It is a 1250 MWe General Electric BWR with a Mark III containment and is located on the east side of the Mississippi River approximately 37 miles north-northeast of Natchez, Mississippi. Grand Gulf is owned by and will be operated by Middle South Energy, Inc., a wholly owned subsidiary of Middle South Utilities, Inc. and Mississippi Power and Light Company. Grand Gulf Unit #1 is scheduled for commercial operation in 1981.

Table 1-1. Major Characteristics of RSS and RSSMAP Studied Plants

RSSMAP PLANT	RSS PLANT USED FOR COMPARISON
Sequoyah #1 PWR · Reactor Vendor - Westinghouse · Architectural Engineer - Tennessee Valley Authority · Four Reactor Coolant Loops · 1148 MWe · Ice Condenser Containment · Now in low power testing	Surry PWR · Reactor Vendor - Westinghouse · Architectural Engineer - Stone and Webster Engineering Corp. · Three Reactor Coolant Loops · 775 MWE · Dry Subatmospheric Containment · Commercial Operation on 12/72
Oconee #3 PWR · Reactor Vendor - Babcock and Wilcox · Architectural Engineer - Duke Power Co. with Assistance from Bechtel Power Corp. · Two Hot Leg Reactor Coolant Loops Four Cold Leg Reactor Coolant Loops · 886 MWe · Dry Containment · Commercial Operation 12/74	SURRY PWR
Calvert Cliffs #2 PWR · Reactor Vendor - Combustion Engineering · Architectural Engineer - Bechtel Power Corp · Two Hot Leg Reactor Coolant Loops Four Cold Leg Reactor Coolant Loops · 850 MWe · Dry Containment · Commercial Operation 4/74	SURRY PWR
Grand Gulf #1 BWR · Reactor Vendor - General Electric Co. · Architectural Engineer - Bechtel Power Corp. · BWR/6 Design · 1250 MWe · Mark III Containment · Commercial Operation scheduled for 1981	Peach Bottom BWR · Reactor Vendor - General Electric Co. · Architectural Engineer - Bechtel Power Corp. · BWR/4 Design · 1065 MWe · Mark I Containment · Commercial Operation 7/74

2.0 METHODOLOGY

As stated in Chapter 1, the RSS Methodology Applications Program consists of two principal tasks: systems analysis and accident process analysis. This chapter will discuss the basic methodology utilized in performing these tasks, differences from the methodology presented in the RSS, and important assumptions and restrictions used in performing the analyses. Details of how the methodology was applied to the analysis of the Grand Gulf #1 power plant can be found in Chapters 4 and 5.

2.1 Review of RSS Methodology

Before discussing the RSSMAP methodology, a brief review of the RSS methodology may be useful in identifying similarities and describing differences between the two methodologies. In the RSS, the methodology consisted essentially of three basic tasks. These included: (1) a systems analysis task, (2) an accident process analysis task, and (3) a consequence analysis task. The first two correspond to RSSMAP tasks. The third task analyzed the accident sequences in terms of consequences to public health and property damage. This third task was not included in this study.

The initial step in the RSS systems analysis task involved the construction of functional event trees. These trees indicate the functions which must be performed by plant systems to mitigate an accident initiated by various loss of coolant accidents (LOCAs) or transients. For LOCAs, these functions were reactor shutdown, emergency core cooling, post accident radioactivity removal, post

accident heat removal, and containment integrity. For transients, the required functions were reactor subcriticality, overpressure protection, vessel water inventory, and heat transfer to the environment. Then system event trees were constructed by identifying the plant systems needed to perform the required post-accident functions. After completing this, the system accident sequences were delineated and a detailed fault tree analysis was conducted on all the systems represented on the event tree to determine the failure modes and failure probability of these systems. In some cases, detailed fault trees were not needed if actual plant failure probability data existed. The fault trees were quantified using a component and human failure data base compiled as part of the RSS. The system failure probability was expressed in terms of a median value with an associated error bound. The error bound was due to uncertainties in the RSS data base.

The final step of the RSS systems analysis task was the quantification of the accident sequences depicted on the system event trees. Any dependencies which existed among the systems in the sequence, which were not explicitly covered by the event tree structure, were identified (i.e., a shared system component) and incorporated into the quantification. System accident sequences with the highest frequencies were then analyzed in terms of accident processes.

The accident process analysis was conducted to determine (1) which of the dominant system accident sequences resulted in core melt, (2) the response of the containment following an accident

and (3) for those sequences predicted to result in containment failure, the amount and types of radioactivity released to the environment. Containment event trees displaying potential containment failure modes were created for each system accident sequence. Probabilities of these failure modes were then estimated. The complete accident sequences (defined as a system accident sequence with its appropriate containment failure mode) were then assigned to one of nine PWR or one of five BWR radioactive material release categories. The categories were ordered in terms of severity with Category 1 representing the most severe radioactive material release. The accident sequence frequencies in each category were then summed in order to assess the release category frequency (per reactor year). It was recognized that there was an uncertainty associated with the release category placement of each sequence. To account for this, the RSS smoothing technique was used; that is, a probability of 0.1 was assigned to an accident sequence being in an adjacent release category, and a probability of .01 was assigned to an accident sequence being two release categories from the one in which it was placed, etc. After applying this technique, the final release category frequency was assessed.

The final RSS task was to analyze the release categories in terms of consequences to public health and property damage. This was acccomplished through the use of various models depicting items such as meteorology, population evacuation, and population dose. Through the use of these models, the consequences of each release category were determined. Multiplication of the frequency of the

release category and its associated consequence resulted in a risk estimate of each category. Summing the risk of all the release categories resulted in an estimate of the total power plant risk.

2.2 RSSMAP Methodology

The RSSMAP methodology is based on that used in the RSS. To meet, in an efficient manner, the objectives of the program stated in the introduction, insights and results from the RSS were used when appropriate. However, certain departures from the RSS methodology did occur and are summarized below.

During the formulation of the event trees, it was decided that a single LOCA tree, rather than three as in the RSS, would be an adequate representation of the plant response to a LOCA of any given break size. The reactor functions incorporated into the Grand Gulf event trees are the same as those used in the RSS except for several variations. The RSS LOCA post-accident heat removal function was split into two functions for Grand Gulf: containment overpressure protection early and containment overpressure protection late. In the transient analysis, the RSS heat transfer to the environment function is called residual heat removal.

One of the insights gained from the RSS was that system failure probabilities are dominated by only a few failure modes such as single, double and common mode hardware and human failures. Because of this insight, elaborate fault tree models to identify all possible system failure modes, as was done in the RSS, were not developed for the RSSMAP. Instead, a "survey and analysis" technique

was used to determine system failure modes. This technique was, in essence, a systematic approach by which the analyst searched for system failure modes. The search was done manually and was usually stopped when all double or triple failure modes were identified. A Boolean equation was then constructed for each system which represented these failure modes. These equations were utilized in the accident sequence analysis described later. (For an example of the "survey and analysis" technique, see Appendix B.) It should be noted that the failure mode search was based largely on systems information gained from the plant FSAR (through Amendment 46), a single visit to the plant, and some follow-up conversations with plant personnel. It is recognized that this limitation in the study does not provide assurance that all system failure modes have been identified.

The RSSMAP system unavailabilities were quantified using the RSS hardware and human error data base, except for those systems for which actual plant failure probability data was available. Throughout the course of this work, point estimate unavailabilities were used in determining the system failure probabilities rather than the median unavailability with its associated error bound as was used in the RSS. This departure from the RSS methodology was made because the additional effort of estimating error bounds was not judged necessary for risk comparisons or the identification of dominant accident contributors.

The final step of the RSSMAP systems analysis task was the performance of a system accident sequence analysis to determine those core melt sequences with the highest frequency. This was done by combining the Boolean equations describing the succeeded and failed systems for each accident sequence, performing a Boolean reduction of the equations to produce sequence cut sets (i.e., the system failures which produce an accident sequence), and quantifying those cut sets using the data base. The cut sets for each accident sequence were summed to arrive at a total sequence frequency. The accident sequence Boolean reduction and cut set quantification was performed with the aid of the SETS and SEP computer codes (Reference 5). In the RSS, the accident sequence analysis was performed largely by hand calculations. In some cases, this may have required some assumptions concerning interactions between systems in a sequence to make the calculations practicable. The increased analytical capability afforded by SETS and SEP allowed for a more rigorous treatment of systems interactions in the RSSMAP. (For more details concerning the systems analysis task, see Chapter 4.)

System accident sequences identified with the highest frequencies were then analyzed in terms of accident processes. The accident process analysis task for the RSSMAP was conducted in a more detailed manner than was done in the RSS. Use was made of a new computer code known as MARCH, and an updated version of the CORRAL code (References 6 and 7).

The MARCH code, developed at Battelle Columbus Laboratories, performs LOCA and transient initiated accident calculations from the time of the initiation of the accident through the stages of blowdown (LOCA only), core heat up, boiloff, core meltdown, pressure vessel bottom head melting and failure, debris-water interaction in the reactor cavity, and interaction of the molten debris with the concrete containment base pad. The mass and energy additions into the containment building during these stages are continuously evaluated and the pressure-temperature response of the containment with or without the engineered safety features is calculated. The MARCH simulation also accounts for metal-water reactions, combustion of hydrogen, and heat losses to structures in the containment. By comparison, the accident process analysis conducted in the RSS was conducted largely with hand calculations, which required several simplifying assumptions (e.g., small LOCAs and transients were treated in a gross manner by comparing them to calculations done for large LOCAs).

The updated version of the CORRAL code uses the same basic analytical models as the RSS version, but has been made more versatile. The code can now model the transport of the radionuclides within the containment in more detail because of the increased capability of handling larger problems.

For each of the dominant system accident sequences, the codes were used in determining possible containment failure modes, estimating the probabilities of each failure mode, and placing each sequence into the four RSS BWR core melt release categories. The non-melt category 5 was found to have a negligible impact on risk in

the RSS and was not included in the RSSMAP. (For more details concerning the accident process analysis task see Chapter 5.)

Upon completion of the accident process analysis, the complete accident sequences (defined as the combined system accident sequence and containment failure mode) were ranked and the dominant accident sequences identified. The final step in the RSSMAP was then to compare the expected risk of the Grand Gulf plant with the RSS BWR. This was done indirectly by comparing the probability (per reactor year) of the four BWR core melt release categories, i.e., the RSSMAP methodology did not include a task to directly analyze the consequences of accident sequences.

3.0 GENERAL PLANT DESCRIPTION AND DIFFERENCES FROM RSS PLANT

The likelihood of certain accident sequences and the factors which cause an accident sequence to dominate the risk associated with a plant are clearly dependent on the plant design. In this section, significant design differences between the Grand Gulf and Peach Bottom units are summarized. Detailed system descriptions and reliability estimates are presented in Appendix B.

Both Grand Gulf units have a BWR/6 boiling water reactor (251-inch diameter vessel with 800 fuel assemblies) designed and supplied by General Electric Company. Each Grand Gulf reactor is designed to operate at a gross electrical power output of approximately 1306 MW and a net electrical output of approximately 1250 MW. The Grand Gulf containment is the Mark III BWR containment incorporating the drywell/pressure suppression concept. The containment is a steel-lined reinforced concrete structure designed by Bechtel Power Corporation. The internal design pressures for the drywell and containment are 30 and 15 psig, respectively.

Peach Bottom units 2 and 3 are both BWR/4 (251-inch diameter vessel with 764 fuel assemblies) boiling water reactors and were also designed and supplied by General Electric. Each Peach Bottom unit is designed to operate at a gross electrical output of 1098 MW and a net eletrical output of 1065 MW. Peach Bottom utilizes a BWR Mark I containment which has a 56 psig internal design pressure.

There are several important differences in the safety systems between the plants which perform the generic LOCA and transient BWR engineered safety functions. These differences are the result

of different systems present at Grand Gulf as well as many differences in piping and circuitry configurations, system success criteria, and test and maintenance intervals for systems which appear at both plants. Some of the more obvious dissimilarities can be noted upon examination of Figures 3-1 and 3-2. These figures depict the Grand Gulf and Peach Bottom Engineered Safety Features (ESF) and related system components in a very simplified manner. Redundancy in systems is not shown except in some cases where number of pumps, etc., are indicated. A brief descriptive summary of all Grand Gulf and Peach Bottom systems analyzed follows. More detailed descriptions can be found in Appendix B.

A word of caution should be made about comparing the system failure probabilities of both plants. The comparison given in the following descriptive summaries is based on an independent comparison of the systems. Interdependencies between the various systems at the plant are not considered at this point. Because of this fact, a statement such as "Grand Gulf System A has a failure probability X times greater or lower than Peach Bottom System A," has no safety significance unless the systems being compared are truly independent of other systems at the plant. For purposes of comparing safety then, the appropriate comparison is the accident sequence frequencies since it is at this point where all system interdependencies are considered. Accident sequences and system interdependencies are discussed in Chapters 4 and 6.

3.1 Grand Gulf Systems Which Do Not Have a Comparable Peach Bottom System

There is only one Grand Gulf system which has no comparable Peach Bottom equivalent. A brief description of the system and its dominant failure modes follow.

3.1.1 Suppression Pool Makeup System (SPMS)

The purpose of this system is to provide water from the upper containment pool to the suppression pool by gravity flow following a LOCA. Water addition to the suppression pool by the SPMS is needed to ensure the capacity of the RHR heat exchangers to safely limit the long-term, post LOCA suppression pool temperature and to ensure that there is sufficient suppression pool vent coverage for all break sizes.

The piping system consists of two 100% capacity lines from the upper containment pool to the suppression pool. Each SPMS makeup line has two normally closed valves in series which automatically open after a LOCA.

Maintenance and hardware failures of the two SPMS makeup lines were assessed to be the dominant cause of failure for this system.

3.2 Grand Gulf Systems Which Have Comparable Peach Bottom Systems

Brief descriptions of the differences between the Grand Gulf and Peach Bottom systems are given below.

3.2.1 Reactor Protection System (RPS)

The RPS for both Grand Gulf and Peach Bottom consists of a control rod system (CRS) and a reactor protection logic system

(RPLS) and is designed to automatically shut down the reactor immediately at the onset of abnormal plant operating conditions.

The RPLS, essentially the same for each plant, is arranged as two separately powered trip systems and has a one-out-of-two twice logic scheme. Two manual scram switches are provided for each Grand Gulf trip system, while Peach Bottom incorporates one manual scram switch for each trip system. The CRS is also essentially the same for both plants. Peach Bottom has 185 control rods while Grand Gulf has 193 rods.

The principal contributors to the RPS unavailability for both Grand Gulf and Peach Bottom are the failure of three adjacent rods to enter the core and a common mode failure arising from miscalibration of RPS sensor switches.[1]

Grand Gulf's RPS unavailability was assessed to be slightly lower than that for Peach Bottom. The difference in unavailabilities was due to the fact that for loss of offsite power sequences at Grand Gulf, RPS logic circuit failures were not included in the RPS unavailability since the RPS will trip due to the initiator.

3.2.2 Emergency AC Power System (EPS)

The major Grand Gulf and Peach Bottom Design characteristics are summarized below for comparison:

Grand Gulf EPS	Peach Bottom EPS
· three diesel generators/unit - no inter-unit bus ties	· two diesel generators/unit with inter-unit bus ties
· load sequencing	· load sequencing

[1] The Reactor Safety Study RPS failure criteria was used in the Grand Gulf analysis.

Grand Gulf EPS (continued)	Peach Bottom EPS (continued)
· three load divisions/unit - one diesel/load division - one division for High Pressure Core Spray - two divisions for remaining redundant ESF	· two load divisions/unit - one diesel/load division
· three independent 120 VAC channels/unit - no inter-unit bus ties	· four 120 VAC channels serving unit 2 and unit 3 - inter-unit bus ties

The significant difference between Grand Gulf and Peach Bottom was the dedicated HPCS load division employed by Grand Gulf.

Peach Bottom and Grand Gulf's EPS unavailabilities were both dominated by the diesel generators failing to start when needed. The unavailability of a one AC electric power train was calculated to be nearly equal for Peach Bottom and Grand Gulf. However, since Grand gulf has a third EPS train dedicated to the High Pressure Core Spray, the total unavailability of all AC power at Grand Gulf is several orders of magnitude lower than at Peach Bottom.

3.2.3 DC Power System (DCPS)

The Peach Bottom DCPS employs four independent 125 VDC power supplies for the unit's ESF equipment. Each of these power supplies includes one 125 volt battery and one battery charger. The Grand Gulf DCPS employs three independent 125 VDC power supplies for the ESF equipment for each unit (1 and 2). Each of these power supplies includes one 125 volt battery and two (redundant) battery chargers. One of the Grand Gulf DC power supplies is dedicated to the High Pressure Core Spray system and the other two power supplies are dedicated to the remaining ESF equipment for the unit.

The DC train unavailabilities for both Grand Gulf and Peach Bottom are dominated by failure of the battery on demand and are therefore equal.

3.2.4 Vapor Suppression System (VSS)

The Vapor Suppression Systems at Grand Gulf and Peach Bottom are both designed to prevent containment overpressurization after a LOCA by condensing steam released from the break. The primary method of achieving vapor suppression at both plants is to bubble the steam through a suppression pool.

The suppression pool at Grand Gulf is open to the primary containment volume and surrounds the drywell. Steam, emitted by a LOCA, passes from the drywell through passive, horizontal vents into the suppression pool. In the case where small amounts of steam leak from the drywell, bypassing the suppression pool, containment sprays can be used to assure vapor suppression.

The suppression pool (or wetwell) at Peach Bottom is a torus, half-filled with water, which is separate from the primary containment volume. During a LOCA, steam is carried to the suppression pool by vent pipes, a ring manifold, and downcomer pipes. Peach Bottom does have wetwell and drywell sprays. No credit was given for these sprays in the RSS analysis, however.

Single failures dominate both the large and small LOCA cases of VSS failure at Peach Bottom. For the small LOCA case, a vacuum breaker being partially open is the dominant failure type. For the large LOCA at Peach Bottom, downcomer pipe ruptures dominate the system failure.

For Grand Gulf, the dominant VSS failure is the event where a large amount of steam bypasses the suppression pool via leaks in the drywell penetrations. Possible steam bypass through open vacuum breakers at Grand Gulf are double failures and were found to add negligibly to the system unavailability.

The VSS unavailability for large LOCAs at Grand Gulf was assessed to be similar to the Peach Bottom estimate. The VSS unavailability for small LOCAs was assessed to be over an order of magnitude smaller at Grand Gulf than the value calculated for Peach Bottom. This difference was primarily due to the passive VSS design employed at Grand Gulf.

3.2.5 High Pressure Core Spray (HPCS)

Although they perform the same function, the Grand Gulf HPCS and Peach Bottom HPCIS are significantly different in design. The Peach Bottom high pressure system is driven by a steam turbine while the Grand Gulf HPCS employs a motor driven pump. Another major design difference is in the method of delivery to the vessel: the Grand Gulf system uses a spray sparger above the core, while the Peach Bottom delivers through a feedwater line.

In other respects, the systems are very similar. Each has the condensate storage tank or the suppression pool as a suction source. The control systems and initiation are very similar; the differences being due to the steam controls needed for the Peach Bottom HPCIS.

Peach Bottom's HPCIS unavailability is dominated by the estimated downtime for maintenance. The reason for this is the large number of motor operated valves for which maintenance would cause

unavailability of the system. Valve maintenance accounts for about half of the total HPCIS unavailability. Maintenance of the turbine driven pump accounts for much of the remainder. Grand Gulf's HPCS unavailability is also dominated by maintenance contributions of the pump and valves and was assessed to be a factor of two lower than Peach Bottom's.

3.2.6 Reactor Core Isolation Cooling System (RCICS)

The RCICS of Grand Gulf and Peach Bottom are similar in design and identical in function. The two systems both rely on turbine driven pumps to deliver the water to the core. Aside from physical layouts, the two systems differ in two aspects. First, the Grand Gulf RCICS delivers water through a spray nozzle above the reactor core while the Peach Bottom system utilizes one of the feedwater lines. Second, after nuclear boiler system isolation, the Grand Gulf RCICS can operate with the Residual Heat Removal System to direct steam from the main steam lines to the RHR heat exchangers. In this way, reactor steam is condensed so that decay and residual heat may be removed if the main condenser is unavailable.

The assessed unavailabilities for the Grand Gulf and Peach Bottom RCIC systems were very similar. Unavailabilities of both systems were dominated by estimated downtime for maintenance.

3.2.7 Low Pressure Core Spray (LPCS)

The two systems are quite different when viewed without consideration of the other ECCS components. The Grand Gulf system is a single pump, single loop system whereas the Peach Bottom system

(the Core Spray Injection System, CSIS) is redundant, consisting of two independent loops and four pumps. The control and initiation of the two systems is the same. Any true comparison must treat the entire ECCS of both reactors, as it is the functionability of the Emergency Core Cooling System as a whole which is important.

Unavailabilities of either or both subsystems of the CSIS are dominated by the estimated outages for maintenance activities on the motor operated valves and pumps. System tests were not significant contributors to overall unavailability and no significant human error single faults were found.

Grand Gulf's LPCS unavailability is also dominated by maintenance contributions of the pump and valves and was assessed to be a factor of two lower than that calculated for a Peach Bottom CSIS train.

3.2.8 Automatic Depressurization System (ADS)

The two ADS systems of Grand Gulf and Peach Bottom are identical in purpose and very similar in design. The circuitries, including the initiating sensors, are almost identical. The major difference is in the valve hardware. The Grand Gulf valves have two solenoid pilot valves, each connected to a different control circuit and each having its own accumulator. The Peach Bottom valves have one pilot valve and accumulator which can be operated by either of two control systems. Grand Gulf uses eight safety/relief valves as ADS valves, any four of which that function results in system success for the worst small break case. At Peach Bottom, five valves belong to the ADS and three of five must function. In both cases, a manual intervention is possible which resets the timer to zero each time it is employed.

The dominant failure contributions for the ADS were the same for Grand Gulf and Peach Bottom. These are the failure of the operator to actuate the ADS after a transient (1.5×10^{-3}) and the unavailability of the two logic circuits to actuate the ADS after a small LOCA (5.0×10^{-3}).

3.2.9 Low Presure Coolant Injection System (LPCIS)

The Low Pressure Coolant Injection Systems at Peach Bottom and Grand Gulf are operating modes of their respective Residual Heat Removal Systems. In the LPCIS mode, water is drawn from the suppression pool and injected into the reactor vessel. Although the primary functions of the two LPCI systems are the same, the actual designs are quite different.

Peach Bottom's LPCIS consists of four pumps which are crosstied to two discharge headers. The Grand Gulf system has three redundant loops, each with its own pump and piping.

The dominant contributor to the LPCIS unavailability at Peach Bottom was from pump and valve maintenance. This was also the dominant contributor at Grand Gulf. The unavailability for an individual LPCIS loop was calculated to be very similar for the two plants.

3.2.10 Residual Heat Removal System (RHRS)

The Residual Heat Removal Systems at Peach Bottom and Grand Gulf are designed to remove decay heat from the suppression pool after an accident. Both RHR systems use the same pumps and pathways used by the LPCIS. In the RHR mode, however, the residual heat removal heat exchangers must be available along with secondary cooling.

The RHRS at Peach Bottom is composed of four pumps, each of which is in series with a heat exchanger. The heat exchanger discharges are all crosstied to two discharge headers. Only two of the three Grand Gulf LPCI trains are equipped with heat exchangers and are therefore available for residual heat removal. Each of the two RHRS trains at Grand Gulf has a pump and a heat exchanger in series.

The cooling water to the heat exchangers is supplied by the Standby Service Water System in the Grand Gulf unit. Each RHR train has its own associated SSWS train. The Service Water System also supplies pump seal and compartment cooling. At Peach Bottom, the RHR heat exchangers are cooled by High Pressure Service Water; while the pumps are cooled by a separate system, the Emergency Service Water System.

An important mode of RHRS operation not available at Peach Bottom is steam condensing. During nuclear boiler system isolation and in conjunction with the operation of the reactor core isolation cooling system and steam blowdown to the suppression pool, steam at reduced pressure and temperature is directed from the main steam lines to the residual heat removal system heat exchanger. Condensate at a temperature not exceeding 140°F is directed to the reactor core isolation system for return to the nuclear boiler system. Noncondensable gases from the heat exchangers are vented to the suppression pool. Steam condensing is manually initiated. In this way, reactor steam is condensed so that decay and residual heat may be removed if the main condenser is unavailable.

As discussed in the Reactor Safety Study (Appendix 2, page 425), the large number of pumps and paths available for cooling and recirculation of the reactor water at Peach Bottom allows for a great deal of diversity in coping with the heat removal task. Any one of the four LPCRS pumps could meet the cooling requirements. The dominant failure identified was a common mode in the Emergency Service Water, which cools the pump compartments.

The unavailability of the Grand Gulf RHRS was dominated by hardware failures and was assessed to be an order of magnitude higher than that for the similar Peach Bottom system for Loss of Coolant Accidents. This difference was primarily due to the smaller number of pumps and paths available for residual heat removal at Grand Gulf and due to the fact that no credit was given to the steam condensing mode of RHR after LOCAs.

3.2.11 Standby Service Water System (SSWS)

The Peach Bottom Service Water System is composed of the HPSWS and ESWS. Both Grand Gulf SSWS and Peach Bottom ESWS are designed to supply cooling to the safety system room coolers and the diesel generator coolers of their respective plants during emergency conditions. Each system supplies cooling water to its room coolers from emergency basins via redundant service water pump trains. After removing heat from the components, the coolant is piped back to the cooling towers where the heat is rejected to the atmosphere. In addition to its two redundant SSW trains, the Grand Gulf SSWS incorporates a separate HPCS service water train. The SSWS supplies cooling to the RHR heat exchangers in emergency conditions. At

Peach Bottom, during an accident, the HPSWS supplies cooling to the RHR heat exchangers.

The Peach Bottom system is shared by both of its units, whereas each unit at Grand Gulf has its own SSWS.

Unavailability of the HPSWS at Peach Bottom is dominated by test and maintenance contributions of the valves and pumps and by a common mode failure of the HPSWS where the operator fails to override some trip relays to manually start the HPSWS.

Unavailability of the ESWS at Peach Bottom is dominated by potential faults in the single output valve. Any plugging of this valve will prevent coolant flow through all unit coolers. Also, a possible failure mode considered was the possibility that this normally keylocked open valve was closed for a maintenance or test act and inadvertently left in a closed position.

Unavailability of Grand Gulf's SSWS was also dominated by maintenance contributions of the pumps and valves in each loop. No common mode failures were identified, however. Unavailability of SSWS loops A and B (which supply ESF components in trains A and B, respectively) simultaneously was assessed to be similar to the RSS values for the ESWS and HPSWS.

3.2.12 Power Conversion System (PCS)

The Power Conversion Systems of Grand Gulf and Peach Bottom are identical in purpose and very similar in design. Each system is designed to produce electrical power from the steam coming from the reactor, condense the steam, and return the water to the reactor as heated feedwater.

The Peach Bottom PCS utilizes three 33 percent motor-driven condensate pumps and three 33 percent turbine-driven feedwater pumps to move water through the system. Two Steam Jet Air Ejector (SJAE) units are used to maintain the condenser vacuum.

At Grand Gulf, the PCS is composed of three 33 percent motor-driven condensate pumps, three 33 percent motor-driven condensate booster pumps, and two 50 percent turbine-driven feedwater pumps. Two SJAEs are also used at Grand Gulf.

The RSS data on Power Conversion Systems was derived from industry data. The unavailabilities used for the PCS at Grand Gulf were the same as those used in the RSS for most sequences. The exception is that the PCS was assumed to be unavailable at Grand Gulf for transient sequences involving stuck-open relief valves and loss of all emergency core cooling. At Peach Bottom, for this type of sequence, it was assumed that the PCS would be available 99 out of 100 times. Refer to the discussion of sequence TPQE in Chapter 6.0.

a High pressure core spray pump.
b Low pressure core spray pump.
c Turbine bypass valve.
d Main steam isolation valves.
e ADS and safety/relief valves.

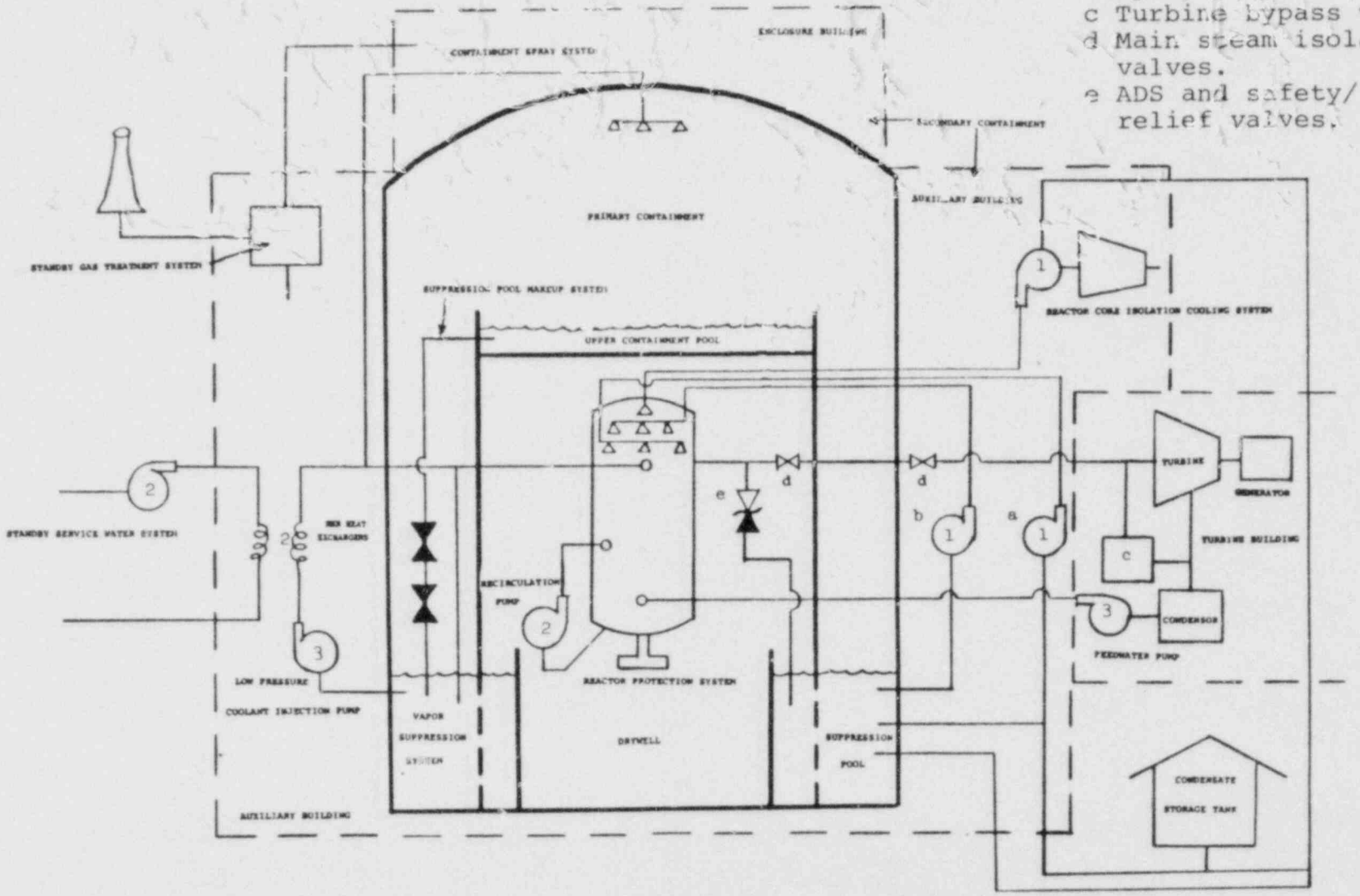


Figure 3-1. Simplified Grand Gulf ESF Diagram

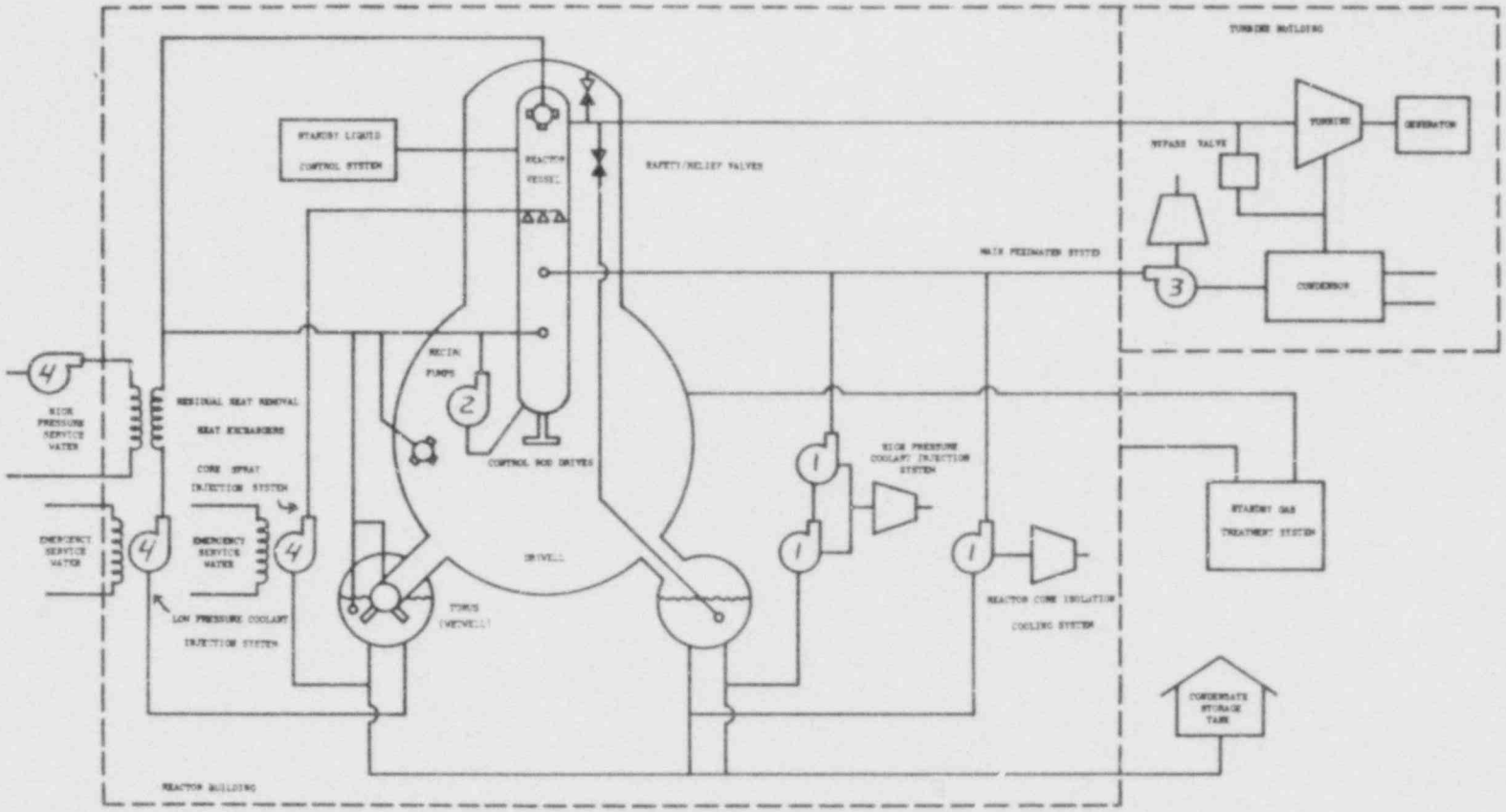


Figure 3-2. Simplified Peach Bottom LSF Diagram

4.0 SYSTEMS ANALYSIS TASK

This chapter summarizes the work done as part of the RSSMAP Grand Gulf #1 systems analysis task. The work was done by Sandia National Laboratories with the aid of Evaluation Associates, Inc. The objective of this task was to identify the dominant system accident sequences which are the major contributors to public risk for Grand Gulf plant. These sequences were identified through the use of event tree and safety system unavailability models. The system unavailability models are, in essence, a Boolean equation representation of a fault tree. The event tree and system unavailability models utilized are discussed in Sections 4.1 and 4.2, respectively. The dominant system accident sequences, generated through the use of these models, are presented in Section 4.3 along with an illustrative example showing how a typical accident sequence calculation was performed.

4.1 Event Trees

Event trees are the structures from which accident sequences are derived. Two event tree types, used in succession, produce the complete accident sequences. The system event trees, the subject of this section, interrelate the initiating event and the engineered safety feature failure events and result in system accident sequences such as "TQW." The containment event trees, done as part of the accident process analysis, relate the possible responses of the containment to the physical situations associated with each system accident sequence. The resulting containment failure modes, designated by terms such as α, γ, or δ are added

to the system accident sequences to form the complete accident sequences such as "TQW-γ." Details of the Containment Event Trees can be found in Chapter 5.

4.1.1 Initiating Events

The type of initiating events considered were the same as in the RSS, i.e., LOCAs and transients. The RSS considered three LOCA size ranges. These were designated "S_2" (1/2" < D $\leq$ 2"), "S_1" (2" < D $\leq$ 6") and "A" (D > 6"), (D being defined as the equivalent diameter of the ruptures). Three sizes were chosen since the number of ECCS and other systems required to mitigate a LOCA was different for each LOCA range. The RSS also considered three types of transients. These were all designated "T" and included reactor shutdowns initiated by:

1) a loss of offsite power,

2) a loss of the main feedwater system not caused by a loss of offsite power, and

3) other causes in which the main feedwater system is initially available.

These transient initiators were assessed to adequately represent a spectrum of generic BWR transients (RSS, Table I, 4-12) in terms of their effects on the mitigating systems.

Based on the study of the Grand Gulf FSAR and discussions with the vendor, it was determined that two LOCA sizes should be chosen based on different ECCS subsystem requirements. These LOCAs are designated S (D $\leq$ 13.5") and A (D > 13.5"). The

estimated frequency of these LOCAs is given in Table 4-1. Since the RSS pipe rupture data is for a generic plant, it was utilized in arriving at these estimates. (As can be noted in this table, some double counting of RSS LOCA frequencies occurred due to overlap of LOCA size ranges between the RSS and Grand Gulf. This did not significantly affect the analysis.)

Two transients were modelled for Grand Gulf, one depicting loss of offsite power events and one covering all others. The loss of offsite power transient is designated T_1 and has a frequency of 0.2/year. The T_{23} transient represents all other transients and is a combination of the RSS T_2 and T_3 initiators.

In the RSS, a loss of main feedwater transient was designated T_2 and had a frequency of 3/year. Other transients with main feedwater initially available were designated T_3 and have a frequency of 4/year. The frequency of Grand Gulf's T_{23} initiator is 7/year. The RSS T_2 and T_3 initiating events can be combined because none of the probabilities of the transient event tree events are sensitive to which initiator actually started the accident.

4.1.2 LOCA Event Tree

The Grand Gulf LOCA event tree is displayed in Figure 4-1. A detailed discussion of this event tree is presented in Appendix A-1. This section will highlight the discussion given there.

A single LOCA event tree was judged to be an adequate representation for the entire spectrum of break sizes. The definitions of the emergency coolant injection and residual heat

removal events change somewhat in the evaluation of the two different LOCAs, but the event tree structure does not.

The systems depicted on the tree perform five plant functions. The combinations of plant systems which are required to successfully perform these functions for the LOCA sizes is displayed in Table 4-2. These functions were chosen since they are either required to successfully mitigate a LOCA or they can affect the consequences of a core melt if mitigation of the LOCA is unsuccessful. The event definitions for the event tree headings are given in Table 4-3.

Dependencies incorporated into the LOCA event tree structure are the following:

1) Core melt is expected to occur given a LOCA and failure to achieve reactor subcriticality. The emergency core cooling and residual heat removal systems would have little effect on this type of accident. A branch for the Vapor Suppression System was included because suppression pool scrubbing of released fission products could reduce the consequences of the LOCA.
2) It is not expected that the residual heat removal systems could affect the consequences of an accident given a loss of all emergency core cooling since the RHR systems cannot prevent or delay the anticipated core melt and containment failure.

4.1.3 Transient Event Tree

The Grand Gulf transient event tree is displayed in Figure 4-2. A detailed discussion of this event tree is presented in

Appendix A-2. This section will highlight the discussion given there.

A single transient event tree was judged to be an adequate model of the plant response for the two transient initiating events considered.

The systems depicted on the tree perform four plant functions. The combination of plant systems which are required to perform these functions for both transients is displayed in Table 4-4. These functions were chosen since they are either required to successfully mitigate a transient or they can affect the consequences of a core melt if mitigation of the transient is unsuccessful. The event definitions for the event tree headings are given in Table 4-5.

Transient sequences with occurrence of event P, i.e., failure of any open safety/relief valve to reseat, and event Q, unavailability of the Power Conversion System, can be treated as a small LOCA since the systems responding to these LOCAs are identical to those required for a small (S) LOCA. These "transient induced LOCAs" are therefore transferred to the LOCA event tree upon occurrence of events P and Q.

Dependencies incorporated into the transient event tree structure are the following:

1) If the RCS relief valves fail to open, the valves cannot, logically, fail to reclose. Also, the operation of the emergency core cooling or residual heat removal systems does not matter since core melt is assumed. This conservative assumption is justified

because the very small probability of event M (failure of S/RVs to open when demanded) is expected to cause all accident sequences containing that event to be relatively small contributors to the risk at Grand Gulf regardless of the release category in which the sequence may appear.

2) If the RCS relief valves fail to reclose and the Power Conversion System is unavailable, the sequence results in a LOCA, and the sequence (and analysis) is continued on the LOCA event tree. This is justified by the fact that the rate of leakage of RCS inventory is sufficient to fit the definition of a LOCA.

3) Failure of the RPS is assumed to lead directly to core melt since the reactor is expected to remain at power levels that are higher than the Residual Heat Removal System capacity.

4) Successful Power Conversion System operation leads to a safe condition since the system will maintain water inventory and will provide long term residual heat removal.

5) Success of the High Pressure Core Spray or Reactor Core Isolation Cooling System precludes the need for the low pressure injection systems since early injection requirements will be satisfied.

6) It is not expected that the residual heat removal systems could affect the consequences of an accident given a loss of all emergency core cooling since the RHR systems cannot prevent or delay the anticipated core melt and containment failure.

4.1.4 Interfacing Systems LOCA

An interfacing system LOCA was analyzed for Grand Gulf and was similar to the one considered for the Surry PWR in the RSS. The initiating event assumes failure of a check valve in one of the residual heat removal system lines and the opening of the normally closed isolation motor operated valve (MOV), which is in series with the check valve. This would allow high pressure coolant water to enter the low pressure piping outside containment and a pipe rupture to occur.

The interfacing system LOCA at Grand Gulf was determined to contribute insignificantly to the overall core melt frequency. Information obtained from the utility indicated that all of the isolation MOVs on the low pressure lines will be permissive closed during high pressure operation. Permissive signals will prevent these valves from opening until reactor pressure has dropped to approximately 700 psi. Rupture of low pressure piping is not expected at this pressure.

4.1.5 Comparison of Grand Gulf and Peach Bottom Event Trees

The Peach Bottom LOCA and Transient even trees are displayed in Figures 4-3 through 4-6. A detailed discussion of the event tree differences are presented in Appendices A-1 and A-2. Some of the more important differences are listed below.

LOCA

1) Response to a LOCA was depicted by one event tree for Grand Gulf rather than the three event trees for Peach Bottom. Some of the event definitions change, however, depending on which initiating LOCA size is being considered.

2) The Peach Bottom LOCA event trees all include an Event B, electric power. The Grand Gulf LOCA tree does not include an electric power event. Instead, electric power dependencies were incorporated directly into the Boolean models developed for each system.

3) The Peach Bottom large LOCA event tree had an Event F, ECF, or Emergency Cooling Functionability. In large LOCAs, substantial blowdown forces can occur which have the potential to damage portions of the core or RCS in ways that can affect the ability of the ECCS to adequately cool the core. For this reason, the ECF event was added after Event E, ECI. ECF was not included in the small LOCA trees since the forces involved are much smaller and the chance of failure considered negligibly small. However, the RSS finally concluded that the large LOCA event with or without ECF probability values included would contribute less than 15 percent over the entire release spectrum. For this reason, ECF was not included in the Grand Gulf analysis.

4) A containment leakage event (CL) was included on the Peach Bottom trees to show that failure or success of

the containment isolation systems will affect the timing of possible ECCS pump failures. A containment leakage event was not included on the Grand Gulf LOCA tree because the ECCS pumps at Grand Gulf are rated to 212°F and would therefore not be expected to fail from primary containment leakage.

5) The events H, I, and J on the Peach Bottom trees depict failure of core cooling systems in the recirculation mode and failure of the service water systems to remove decay and sensible heat from the wetwell and pump compartments. These three events have been combined into event I on the Grand Gulf LOCA tree since no "new" accidents, in terms of consequences, are created by splitting out the RHR and cooling water failures.

Transient

1) In the RSS, sequences involving a stuck open relief valve were developed and quantified directly on the transient tree. These types of sequences are treated as special events on the Grand Gulf transient tree. All transient induced LOCAs with failure of the Power Conversion System start on the transient tree and transfer to the LOCA tree after events P and Q. Once on the LOCA tree, the sequences are analyzed as small (S) LOCAs.

4.2 Safety System Unavailability Models

Each system represented on the event trees, except for those where plant and/or industry data existed, was reviewed and analyzed in order to determine system failure modes. An insight gained from the RSS was that system unavailabilities are usually dominated by single, double, common mode, hardware, and human failures. Because of this insight, elaborate fault tree models to identify all possible system failure modes were not used. Instead, a "survey and analysis" technique was used to determine system failure modes. This technique is, in essence, a systematic approach by which an analyst searches for system failure modes.

The first step in conducting a typical survey and analysis was to review all available information pertaining to a Grand Gulf system. Sources of information available for this study were the FSAR system descriptions and drawings and discussions with plant personnel.

The next step was to review the similar BWR system analyzed in the RSS. The purpose of this review was to gain insight concerning typical types of important system failure modes (e.g., singles, doubles, human error, test, maintenance, and common mode faults). Based on the Grand Gulf system information and RSS insights, the analyst manually conducted a failure mode search. Identification of single and common mode failures were made first, followed by doubles, test, and maintenance contributions. Any interactions that a system had with other systems on the event tree, such as a shared component or actuation system, were noted.

The failure modes were then quantified using the RSS hardware and human error data base. In some instances, due to a lack of detailed component information, component unavailabilities were taken directly from the similar system analyzed in the RSS. This was primarily done in obtaining estimates of control circuit unavailabilities for pumps and valves.

During the course of the analysis, it was generally found that most systems which appear on the event trees share a number of components and support systems. Because of this fact, it was necessary to construct a Boolean equation describing the system failure modes so that these interdependencies could be properly treated during the accident sequence calculations. Some systems, however, were assessed to be independent or nearly independent of all other event tree systems. A Boolean equation describing failure modes for independent systems was not necessary since the system unavailability could be simply multiplied into the accident sequence calculation.

A "survey and analysis" for each of 12 Grand Gulf safety systems can be found in Appendices B-1 through B-12. The operation of most of these systems appear as events on the event trees. Some of these are support systems (e.g., the emergency AC and DC power systems and the Standby Service Water System) which are common to several event tree systems. Each appendix includes a derivation of the Boolean equation(s) describing system failure and an unavailability estimate assuming independence from all other Grand Gulf systems. In many instances more than one Boolean equation was derived for a particular system because

some system failure modes were different depending on the event tree initiating event.

4.3 Accident Sequence Analysis

The final step of the Grand Gulf systems task was the performance of a system accident sequence analysis to determine the frequencies of the core melt sequences. This was done by combining the Boolean equations describing the succeeded and failed systems for each accident sequence, performing a Boolean reduction to produce sequence cut sets (i.e., the minimum combination of failures which produce an accident sequence), and quantifying these cut sets using the data base. The cut sets for each accident sequence were summed to arrive at a total sequence frequency. The accident sequence Boolean reduction and cut set quantification was performed by the SETS and SEP computer codes, respectively. These sequences were then given to Battelle Columbus Laboratories and were analyzed in terms of accident processes (see Chapter 5).

An example which illustrates the procedure utilized in performing the system accident sequence analysis follows in Section 4.3.1.

4.3.1 Generating and Quantifying Accident Sequence Cut Sets - An Example

The sequence chosen to illustrate the sequence quantification procedure is the transient sequence T_1QUW. It is a transient initiated by a loss of offsite power (T_1) followed by a failure to restore the power conversion system (Q), subsequent failure of the Reactor Core Isolation Cooling System and High Pressure Core

Spray (U), and failure of the Residual Heat Removal System (W). This sequence is represented by sequence 5 on the transient event tree and leads to a core melt.

The sequence label T_1QUW is a convenient identifier since it represents all the systems which failed in the sequence. This convenient identifier, however, should not be confused with the Boolean representation of the same sequence. Besides the systems which failed in this sequence, several systems succeeded. The Reactor Protection System successfully terminated the fission process (event $\overline{C}$). The safety/relief valves opened ($\overline{M}$). The safety/relief valves reclosed ($\overline{P}$) and the low pressure emergency core cooling systems operated successfully ($\overline{V}$). The complete Boolean representation of this sequence includes both the succeeded and failed systems and would be $T_1\ \overline{C}\ \overline{M}\ \overline{P}\ Q\ U\ \overline{V}\ W$. Quantification of this accident sequence requires the use of the Boolean sequence representation so that interdependencies between the events can be incorporated.

A number of the events in this sequence are independent from all other events. These are T_1, $\overline{C}$, $\overline{M}$, and $\overline{P}$. Since event T_1 is independent, its frequency can be simply multiplied together with the unavailability calculated for the rest of the dependent events. Independent complement events were always dropped out before the Boolean reduction process since they share no common terms with other events and have probabilities that are generally close to unity. Therefore, the independent complement events $\overline{C}$, $\overline{M}$, and $\overline{P}$ are now dropped. It is important to consider dependent complement events in the Boolean reduction of the

system equations to ensure that all system interactions are considered. This will be explained in the following paragraphs.

The rest of the events in the sequence ($QU\overline{V}W$) are interdependent due to sharing of various Boolean terms. In order to properly treat these interdependencies in the accident sequence analysis, Boolean equations must be written for each of the systems defined by Q, U, $\overline{V}$, and W. A product of these Boolean equations was then taken and the resultant equation Boolean reduced and quantified. This quantification of events $QU\overline{V}W$ will then be multiplied by the independent event frequency of T_1 (.2) which will produce the TQUW sequence frequency.

The event definitions for Q, U, $\overline{V}$, and W can be found in Appendix A-2. These definitions and the Boolean models of the systems involved are described below.

For this sequence, Q is defined as the failure of the Power Conversion System (PCS) to be restored within 30 hours. Thirty hours is the time to containment failure predicted for this accident by Battelle Columbus Laboratories. PCS restoration for T_1 initiators depends primarily on whether or not offsite power is restored. Therefore, in Boolean terms,

$$Q = LOPNRE*LOPNRL,$$

where LOPNRE represents failure to recover offsite power early (within one half hour) and LOPNRL represents nonrecovery within 30 hours given LOPNRE.

Event U is defined as the failure of both the Reactor Core Isolation Cooling System (RCICS) and High Pressure Core Spray

(HPCS) to provide high pressure core cooling. Therefore, in Boolean terms,

$$U = RCICS*HPCS.$$

This equation for U will now be expanded by substituting the Boolean equations which model the RCICS and HPCS for T_1 transients. The following two equations are described in detail in Appendices B-6 and B-5.

$$RCICS = R + RSV + LOPNRE*EPS1*BATA.$$

$$HPCS = H + HACT + LOPNRE*EPS3.$$

Therefore,

$$U = (R + RSV + LOPNRE*EPS1*BATA)*(H + HACT + LOPNRE*EPS3)$$

The above equation was used to model event U for T_1 initiators.

Event V is defined as failure of the Low Pressure Emergency Core Cooling Systems (LP ECCS). Failure can occur if the Automatic Depressurization System (ADS) fails or if the Low Pressure Core Spray (LPCS) and two of three Low Pressure Coolant Injection System (LPCIS) trains fail.

Therefore, in Boolean terms,

$$V = ADS + LPCS*(LPCIA*LPCIB + LPCIA*LPCIC + LPCIB*LPCIC),$$

where LPCIA represents LPCIS train A, etc. This equation for V will now be expanded by substituting the Boolean equations which model the ADS, LPCS, and LPCIS for T_1 transients. The following equations are described in detail in Appendices B-8, B-7, and B-9, respectively.

$$ADS = OP$$

$$LPCS = L + LRACT + LOPNRE*EPS1$$

$$LPCIA = LA1 + LA2 + LRACT + LOPNRE*EPS1$$

$$LPCIB = LB1 + LB2 + BCACT + LOPNRE*EPS2$$

$$LPCIC = LC + BCACT + LOPNRE*EPS2.$$

Substituting these equations into the equation for V gives:

$$V = OP + (L + LRACT + LOPNRE*EPS1)*[(LA1 + LA2 + LRACT + LOPNRE*EPS1)*(LB1 + LB2 + BCACT + LOPNRE*EPS2) + (LA1 + LA2 + LRACT + LOPNRE*EPS1)*(LC + BCACT + LOPNRE*EPS2) + (LB1 + LB2 + BCACT + LOPNRE*EPS2)*(LC + BCACT + LOPNRE*EPS2)]$$

The above equation was used to model event V for T_1 initiators. For the sequence being considered, $T_1 \overline{C}\ \overline{M}\ \overline{P}\ Q\ U\ \overline{V}\ W$, we are interested in the complement (or success) of event V. Event $\overline{V}$ represents the success of low pressure core cooling and can be represented by complementing the above equation for V. When complementing a Boolean equation, each event is complemented and "or" gates (+) are replaced with "and" gates (*) and vice versa. Therefore,

$$\overline{V} = \overline{OP}*[\overline{L}*\overline{LRACT}*(\overline{LOPNRE} + \overline{EPS1}) + \overline{LA1}*\overline{LA2}*\overline{LRACT}*(\overline{LOPNRE} + \overline{EPS1})*\overline{LB1}*\overline{LB2}*\overline{BCACT}*(\overline{LOPNRE} + \overline{EPS2}) + \overline{LA1}*\overline{LA2}*\overline{LRACT}*(\overline{LOPNRE} + \overline{EPS1})*\overline{LC}*\overline{BCACT}*(\overline{LOPNRE} + \overline{EPS2}) + \overline{LB1}*\overline{LB2}*\overline{BCACT}*(\overline{LOPNRE} + \overline{EPS2})*\overline{LC}*\overline{BCACT}*(\overline{LOPNRE} + \overline{EPS2})]$$

It is important to include complemented system equations when Boolean reducing combinations of dependent events. Inclusion of the $\overline{V}$ equation in the Boolean reduction of sequence $T_1QU\overline{V}W$ assures the analyst that common mode failures between the low pressure injection systems and the high pressure or RHR systems do not contribute to the sequence probability. After the reduction process, complement events are dropped from the cut sets so that the cut sets will include only failures.

Event W for transients is defined as failure of the Residual Heat Removal System (RHRS) to remove decay heat from the containment. The RHRS has two heat removal trains (A and B); only one of which is required to operate for RHR success. Each train can operate in one of two modes. In the suppression pool cooling mode, water is circulated from the suppression pool, through the RHR heat exchangers, and back to the suppression pool. The Standby Service Water System (SSWS) is required in this mode to deliver cooling water to the secondary sides of the RHR heat exchangers. In the steam condensing mode, steam is condensed in the RHR heat exchangers and heat is removed by the SSWS. The RCICS is required for steam condensing to draw condensate from the heat exchangers. Refer to Figure B10-2. RHRS failure is therefore the inability of both RHR trains to remove heat by one of the two heat removal modes. In Boolean terms,

$$W = (RHRA + SSWA)*(RHRB + SSWB)*$$
$$(RCICS + (SCA + SSWA)*(SCB + SSWB)).$$

The terms RHRA and RHRB represent RHRS suppression pool cooling mode failure of trains A and B. The terms SCA and SCB represent RHRS steam condensing mode failure of trains A and B. The terms SSWA and SSWB represent SSWS failure of trains A and B. The Boolean equations for these terms are described in more detail in Appendices A-2, B-6, B-2, B-10, and B-12, and are given below.

RHRA = LA2 + PA27 + VGA1 + VGA2 + LRACT + LOPNRL*LOPNRE*EPS1

RHRB = LB2 + PB27 + VGB1 + VGB2 + BCACT + LOPNRL*LOPNRE*EPS2

SCA = VGA1 + SCVA

SCA = VGB1 + SCVB

RCICS = R + RSV + LOPNRE*EPS1*BATA

SSWA = SSA + SAC + LOPNRE*LOPNRL*EPS1

SSWB = SSB + SBC + LOPNRE*LOPNRL*EPS2

EPS1 = BATA + DIESEL1 + V1 + SSA + SAC

EPS2 = BATB + DIESEL2 + V2 + SSB + SBC

EPS3 = BATC + DIESEL3 + V3 + SSC + SCC

The Boolean model for event W for T_1 initiators is obtained by substituting the above equations into the equation given for W previously.

In general, each term in the expanded equations for U, $\overline{V}$, and W represents failure or success of a group of system components. These groups or modules were constructed in order to reduce the number of terms in the Boolean equations. This greatly simplifies the accident sequence calculation, i.e., reduces the computer time required to perform the Boolean reduction. A

module was created when it was assessed that a group of components, such as a pump train or control circuit actuation train, were independent from all other plant components or modules.

A product of the the expanded Boolean equations for Q, U, $\overline{V}$, and W is formed and Boolean reduced. This reduction was performed by the SETS computer code (reference 5). Reduction involves the elimination of redundant terms by applying the Boolean identities $P \cdot \overline{P} = \emptyset$, $P + PQ = P$, and $P \cdot P = P$. Applying these identities eliminates a large number of the redundant terms. However, due to the addition of complement events in the Boolean equation, several redundant terms still remain. These redundant terms were eliminated by removing all complemented events from the remaining terms and reapplying the second Boolean identity given above. For example, after applying the Boolean identities the first time, two terms in the reduced Boolean equation may be of the form $AB\overline{C} + AB\overline{D}$. Since we are interested in the minimum number of component/module <u>failures</u>, or minimal cut sets, which cause an accident sequence to occur, the events $\overline{C}$ and $\overline{D}$, which represent component/module <u>success</u>, are not important in the final results. These two terms can be replaced with the term AB. Reducing the equation a second time yielded terms which represent the sequence minimal cut sets.

After obtaining the sequence minimal cut sets, the next step was to quantify them. This was done by substituting the point estimate unavailabilities for each term into the cut sets and performing the arithmetic. The arithmetic was performed by the SEP computer code (reference 5). Those cut sets with the

highest frequency were then identified. These cut sets are the dominant contributors to the sequence frequency. The total sequence frequency was calculated by summing all the sequence cut set frequencies. A list of the dominant cut sets and estimates of the T_1QUW sequence frequency can be found in Table 4-6. The dominant cut sets are characterized by nonrecovery of offsite power, failure of two diesel generators which cause the HPCS and one RHR train to be unavailable, and hardware failure of the RCICS and the other RHR train.

The results of reducing and quantifying the events $QU\overline{V}W$ gives 8.1×10^{-7}. It should be noted that this probability is higher than what would be obtained by multiplying the "independent" Q, U, $\overline{V}$, and W probabilities together. Multiplying this probability by the independent event frequency of T_1 gives the T_1QUW sequence frequency.

$$T_1QUW = (.2)(8.1 \times 10^{-7}) = 1.6 \times 10^{-7} \text{ per reactor year}$$

For sequences involving event W, an additional recovery term was added. Containment failure and subsequent core melt is expected to occur in 30 hours following residual heat removal failure according to the accident analysis performed by Battelle Columbus Laboratories. It is assumed that an attempt will be made to restore or repair any components necessary for residual heat removal during this period. The probability that repairs are not completed within 30 hours given that the mean repair time is 19 hours, is conservatively estimated by an exponential repair distribution as was done in the RSS,

$$P(\text{RHRS not repaired}) = \exp(-30/19) \approx .21$$

Therefore, the total sequence frequency for T_1QUW becomes

$$T_1QUW = (1.6\text{x}10^{-7})(.21) = 3.4 \text{ x } 10^{-8} \text{ per reactor year}$$

4.3.2 Identification of the Dominant System Accident Sequences

Using the procedure described in the previous section, each potential core melt event tree sequence was quantified. All of the core melt sequences which have frequencies larger than 10^{-10} are listed in Tables 4-7, 4-8, and 4-9. These sequences were given to Battelle Columbus Laboratories and analyzed in terms of accident processes. Work at Battelle consisted of attaching an appropriate containment failure mode probability for those sequences which were found to lead to core melt and the placement of the sequences in their proper BWR release category. (Battelle's work is described in detail in Chapter 5).

Based on the estimated sequence frequency and release category placement, those accidents sequences which dominate the risk at Grand Gulf were identified. These sequences and the most important system failures which cause the sequence to occur (i.e., sequence cut sets) are discussed in detail in Chapter 6.

Table 4-1. RSS and Estimated Grand Gulf LOCA Frequencies

RSS LOCA		RSS LOCA FREQUENCY	GRAND GULF LOCA		ESTIMATED LOCA FREQUENCY
$S_2(1/2" < D \leq 2")$	=	1×10^{-3}/yr.	$S(D \leq 13.5")$	=	$S_{2_{RSS}} + S_{1_{RSS}} + A_{RSS}$
				=	$1.0 \times 10^{-3} + 3.0 \times 10^{-4} + 1.0 \times 10^{-4} = 1.4 \times 10^{-3}$/yr.
$S_1(2" < D \leq 6")$	=	3×10^{-4}/yr.			
$A(D > 6")$	=	1×10^{-4}/yr.	$A(D > 13.5")$	=	$A_{RSS} = 1.0 \times 10^{-4}$/yr.

Table 4-2. Alternate Equipment Success Combinations for Functions Incorporated into the Grand Gulf LOCA Event Tree

LOCA Size	Reactor Subcriticality	Emergency Core Cooling (1)	Early Containment Overpressure Protection	Late Containment Overpressure Protection (Residual Heat Removal)	Post Accident Radioactivity Removal
Greater than 13.5 inches "A" LOCA	Reactor Protection System (RPS) Required	High Pressure Core Spray or Low Pressure Core Spray or 3 of 3 Low Pressure Coolant Injection System Trains	Vapor Suppression System (VSS)	Suppression Pool Makeup System (SPMS) and Residual Heat Removal train A and Standy Service Water (SSWS) train A in suppression pool cooling mode or SPMS and RHR train B and SSWS train B in suppression pool cooling mode	Vapor Suppression System (VSS)
Less than 13.5 inches "S" LOCA		Reactor Core Isolation Cooling System or High Pressure Core Spray or the Automatic Depressurization System (ADS) and Low Pressure Core Spray or ADS and 2 of 3 Low Pressure Coolant Injection System trains			

(1) No credit was given for the Power Conversion System after LOCAs (except transient induced LOCAs) since the Main Steam Isolation Valves will be interlocked closed due to high drywell pressure.

Table 4-3. Event Definition for LOCA Event Tree

LOCA - A breach of the pressure boundary of the reactor coolant system (RCS) which causes an uncontrollable loss of water inventory. There are two LOCA categories.

A - Large LOCA - A breach of the RCS with a flow area greater than 1 ft^2 (A > 13.5" diameter).

S - Small LOCA - A breach of the RCS with a flow area less than 1 ft^2 (S $\leq$ 13.5" diameter).

C - Reactor Protection System (RPS) - Failure of the Reactor Protection System to obtain and maintain reactor subcriticality.

D - Vapor Suppression System (VSS) - Failure of the suppression pool or containment sprays to condense steam produced by a LOCA.

E - Emergency Coolant Injection (ECI) - Failure to provide sufficient water to the core to prevent core melt.

- ECI for Large (A) LOCAs - Failure to provide flow to the RCS from the HPCS or the LPCS or 3 out of 3 LPCI trains.
- ECI for Small (S) LOCAs - Failure to provide flow to the RCS from the HPCS, RCICS, LPCS, or 2 out of 3 LPCI trains. The ADS is required for successful LPCS or LPCI operation to reduce system pressure.

I - Residual Heat Removal (RHR) - Failure of the Residual Heat Removal System (RHRS) in conjunction with Standby Service Water System (SSWS) to remove decay heat from the containment. The SSWS is required to supply cooling water to the secondary sides

Table 4-3. Event Definition for LOCA Event Tree (Cont.)

of the RHR heat exchangers. The RHRS can successfully remove heat using either train A or B in the suppression pool cooling mode.

Table 4-4. Alternate Equipment Success Combinations for Functions Incorporated into the Grand Gulf Transient Event Tree

Reactor Subcriticality	Reactor Coolant System Over-pressure Protection	Emergency Core Cooling	Residual Heat Removal
Control rods inserted into the core by the Reactor Protection System. or Recirculation pump trip and operator actions to manually shut down the reactor.	Safety/relief valves open when demanded and then reclose.	Power Conversion System or High Pressure Core Spray or Reactor Core Isolation Cooling System or Automatic Depressurization System (ADS) and Low Pressure Core Spray or ADS and 2 of 3 Low Pressure Coolant Injection System Trains	Power Conversion System or Residual Heat Removal (RHR) train A and Standby Service Water System (SSWS) train A in suppression pool cooling mode or RHR train A and SSWS train A in steam condensing mode or RHR train B and SSWS train B in suppression pool cooling mode or RHR train B and SSWS train B in steam condensing mode

Table 4-5. Event Definitions for Transient Event Tree

T_1 or T_{23} Transients - Any abnormal condition in the plant which requires that the plant be shut down, but does not directly breach RCS integrity.

- T_1 - Shutdown initiated by a loss of offsite power.
- T_{23} - Shutdown initiated by a loss of main feedwater caused by other than a loss of offsite power, and shutdowns with main feedwater initially available.

C - Reactor Subcriticality (RS) - Failure of the Reactor Protection System or the Standby Liquid Control System in conjunction with a recirculation pump trip to obtain and maintain reactor subcriticality.

M - Safety/Relief Valves Open (S/R VO) - Failure of sufficient S/RVs to open and relieve excess primary system pressure.

P - Safety/Relief Valves Reseat (S/R VR) - Failure of any open S/RVs to reseat.

Q - Power Conversion System (PCS) - Failure of the PCS to start removing decay heat in the required time (one-half hour when ECCS injection fails and about 30 hours when injection succeeds).

U - High Pressure Core Spray or Reactor Core Isolation Cooling System (HPCS or RCICS) - Failure of the HPCS or RCICS to provide high pressure makeup to the reactor vessel.

Table 4-5. Event Definitions for Transient Event Tree (Cont.)

V - Low Pressure Emergency Core Cooling Systems (LP ECCS) - Failure of the Low Pressure Core Spray (LPCS) or two of three Low Pressure Coolant Injection (LPCI) trains to provide low pressure makeup to the reactor core. The Automatic Depressurization System (ADS) is required for successful LPCS and LPCIS operation.

W - Residual Heat Removal (RHR) - Failure of the Residual Heat Removal System (RHRS) in conjunction with the Standby Service Water System (SSWS) to start removing decay heat from the containment within about 30 hours. The SSWS is required to supply cooling water to the secondary sides of the RHR heat exchangers. For transients where ECCS injection succeeds, one of two RHRS loops operating in either the suppression pool cooling mode or steam condensing mode will provide RHR.

Table 4-6. Dominant Cut Sets for Sequence T_1QUW

Cut Set	Cut Set Frequency	Term Description
T_1*LOPNRE*LOPNRL *DIESEL2*DIESEL3*R *VGA2*RECOVERY	1.3×10^{-9}	T_1 - Loss of offsite power; $F(T_1) = .2$/R-yr.
		LOPNRE - Nonrecovery of off-site power within one half hour; P(LOPNRE) = .2
		LOPNRL - Nonrecovery of off-site power within 30 hours given LOPNRE; P(LOPNRL) = .1
		DIESEL2 - Failure of diesel generator #2 to provide emergency power; P(DIESEL2) = 3.6×10^{-2}
		DIESEL3 - Failure of diesel generator #3 to provide emergency power; P(DIESEL3) = 3.6×10^{-2}
		R - Hardware failure of the Reactor Core Isolation Cooling System; P(R) = 5.1×10^{-2}
		VGA2 - Valve failure in the RHR heat exchanger bypass line, suppression pool return line, pump room cooling line, or seal cooling line (Train A); P(VGA2) = 2.4×10^{-2}
		RECOVERY - Failure to restore maintenance or test faults or take other corrective action within 30 hours; P(RECOVERY) = .21

Table 4-6. Dominant Cut Sets for Sequence T_1QUW
(Continued)

Cut Set	Cut Set Frequency	Term Description
T_1*LOPNRE*LOPNRL *DIESEL1*DIESEL3*R *VGB2*RECOVERY	$1.3x10^{-9}$	T_1, LOPNRE, LOPNRL, DIESEL3, R, RECOVERY (discussed above)
		DIESEL1 - Failure of diesel generator #1 to provide emergency power; P(DIESEL1) = $3.6x10^{-2}$
		VGB2 - Valve failure in the RHR heat exchanger bypass line, suppression pool return line, pump room cooling line, or seal cooling line (Train B); P(VGB2) = $2.4x10^{-2}$
T_1*LOPNRE*LOPNRL *DIESEL3*VGA2* VGB2*R*RECOVERY	$8.9x10^{-10}$	T_1, LOPNRE, LOPNRL, DIESEL3, VGA2, VGB2, R, RECOVERY, (discussed above)
T_1*LOPNRE*LOPNRL *DIESEL2*DIESEL3 *VGA1*R*RECOVERY	$8.3x10^{-10}$	T_1, LOPNRE, LOPNRL, DIESEL2, DIESEL3, R, RECOVERY (discussed above)
		VGA1 - Failure of valves on the inlet or outlet piping of RHR heat exchanger A; P(VGA1) = $1.5x10^{-2}$
T_1*LOPNRE*LOPNRL *DIESEL1*DIESEL3 *VGB1*R*RECOVERY	$8.3x10^{-10}$	T_1, LOPNRE, LOPNRL, DIESEL1, DIESEL3, R, RECOVERY, (discussed above)
		VGB1 - Failure of valves on the inlet or outlet piping of RHR heat exchanger B; P(VGB1) = $1.5x10^{-2}$

Table 4-7. Grand Gulf LOCA Sequences > 10^{-10}

Large LOCAs		Small LOCAs	
AI	2.6×10^{-7}	SI	4.6×10^{-6}
AE	5.0×10^{-9}	SC	1.1×10^{-8}
AC	7.7×10^{-10}	SE	8.2×10^{-9}
		SDI	3.0×10^{-10}

Table 4-8. Grand Gulf Transient Induced LOCA Sequences > 10^{-10}

T_1		T_{23}	
T_1PQI	1.6×10^{-6}	T_{23}PQI	3.7×10^{-6}
T_1PQE	2.3×10^{-7}	T_{23}PQE	5.4×10^{-7}

Table 4-9. Grand Gulf Transient Sequences > 10^{-10}

T_1		T_{23}	
T_1QW	6.2×10^{-6}	T_{23}QW	1.2×10^{-5}
T_1QUV	1.5×10^{-6}	T_{23}C	5.4×10^{-6}
T_1C	1.2×10^{-7}	T_{23}QUW	7.0×10^{-8}
T_1QUW	3.4×10^{-8}	T_{23}QUV	5.6×10^{-8}

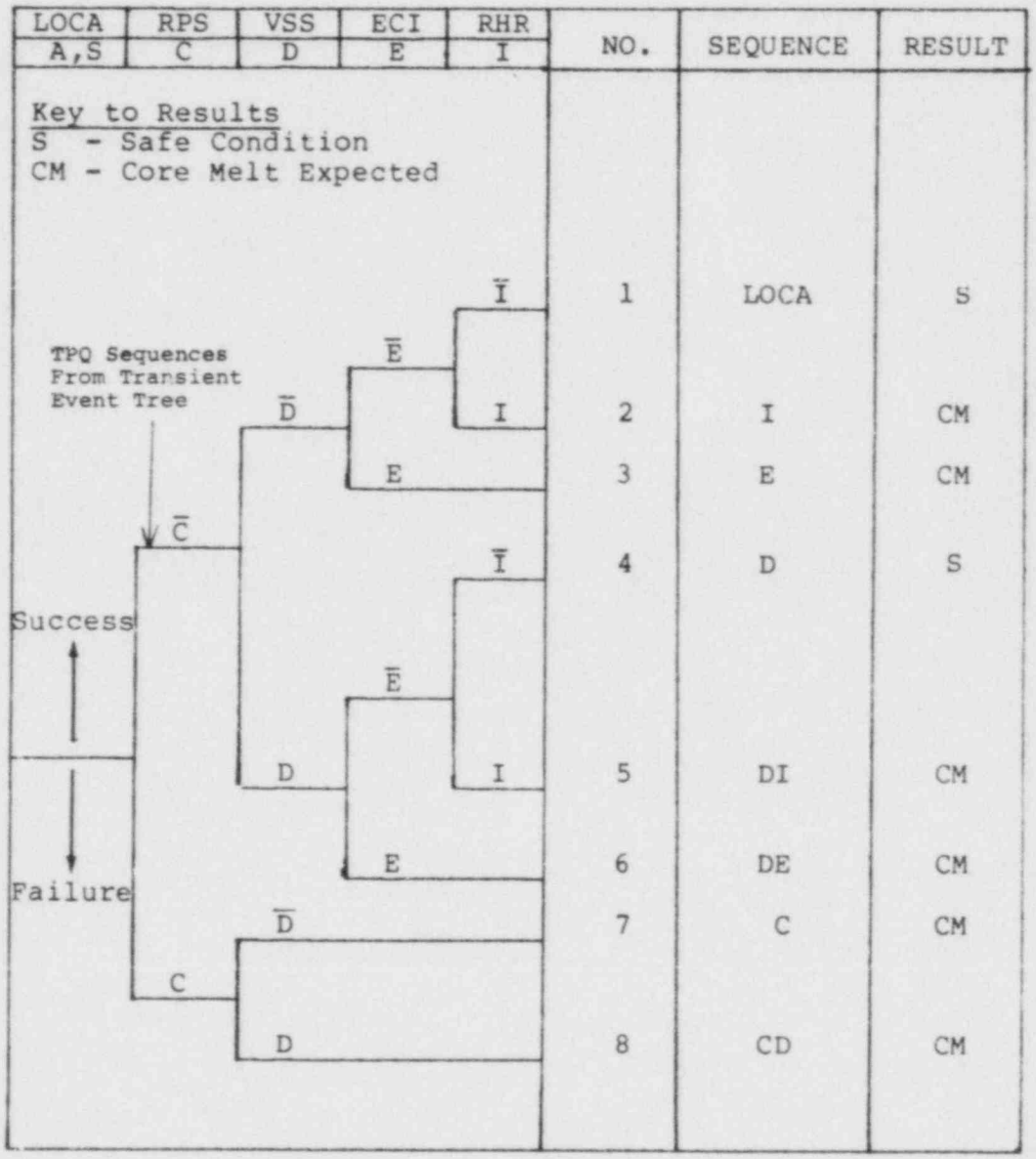


Figure 4-1. Grand Gulf LOCA Event Tree

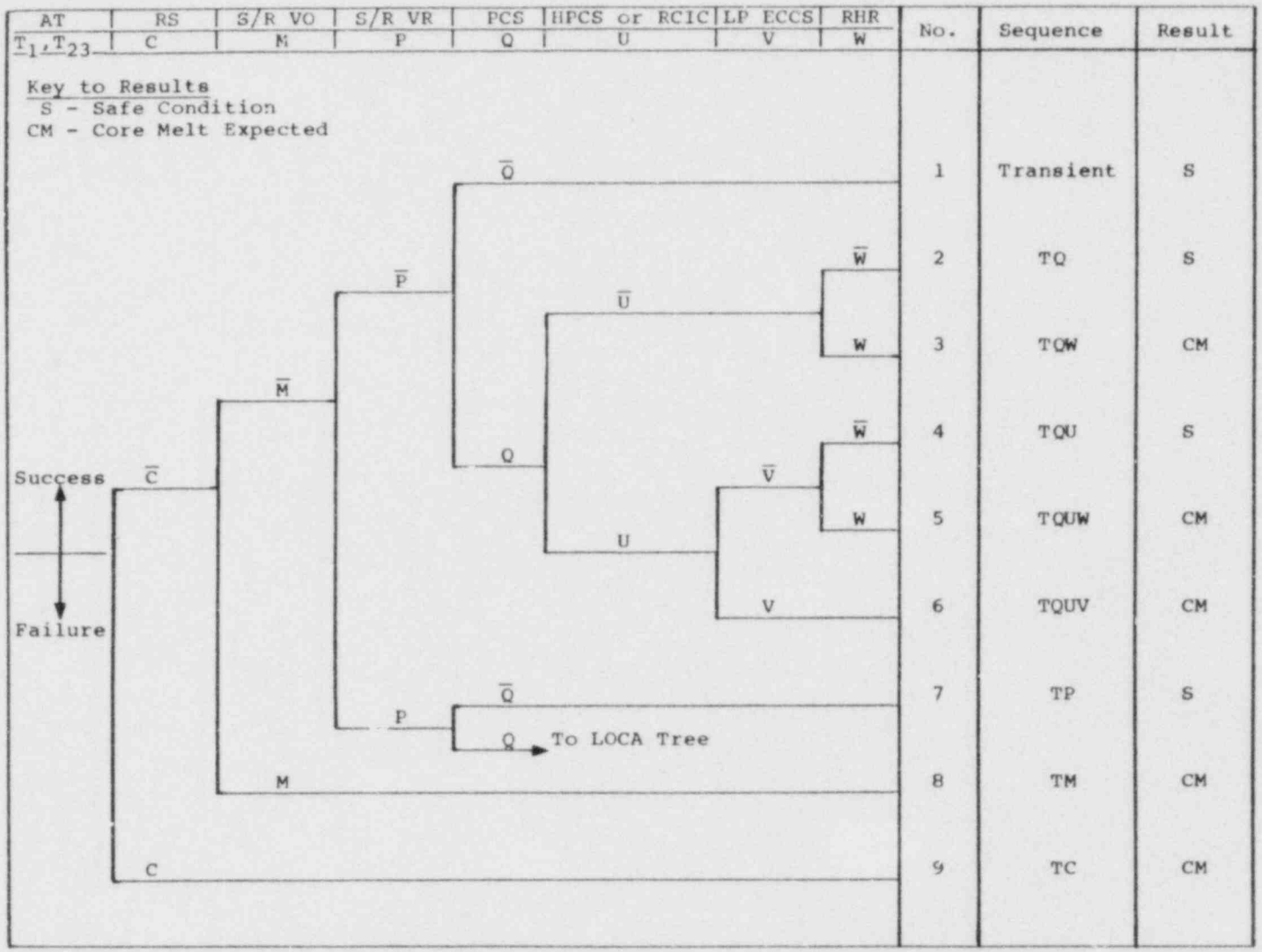
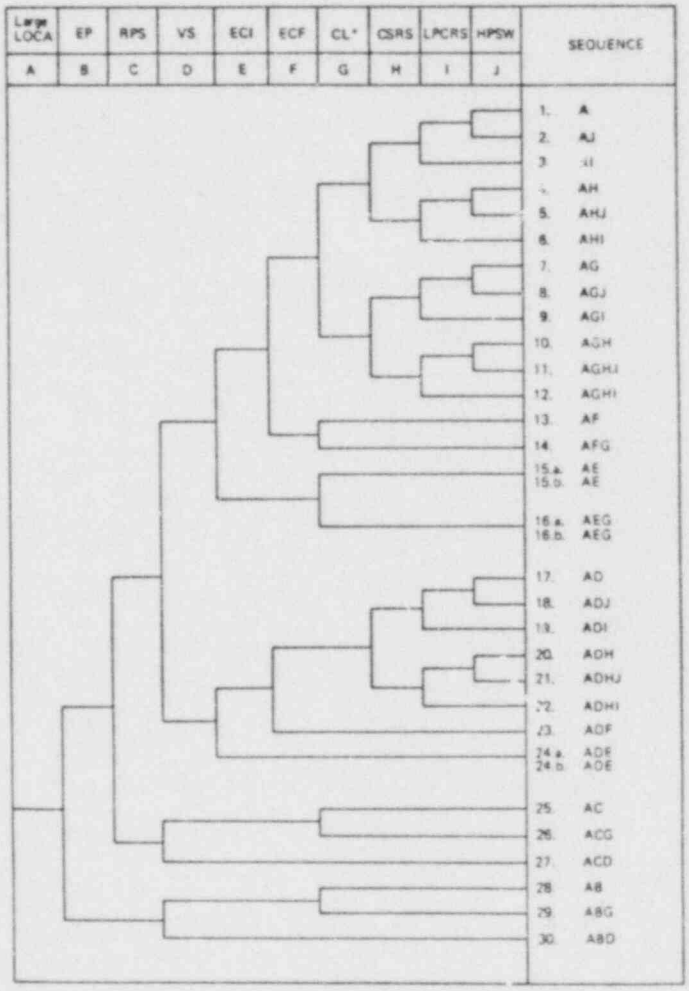
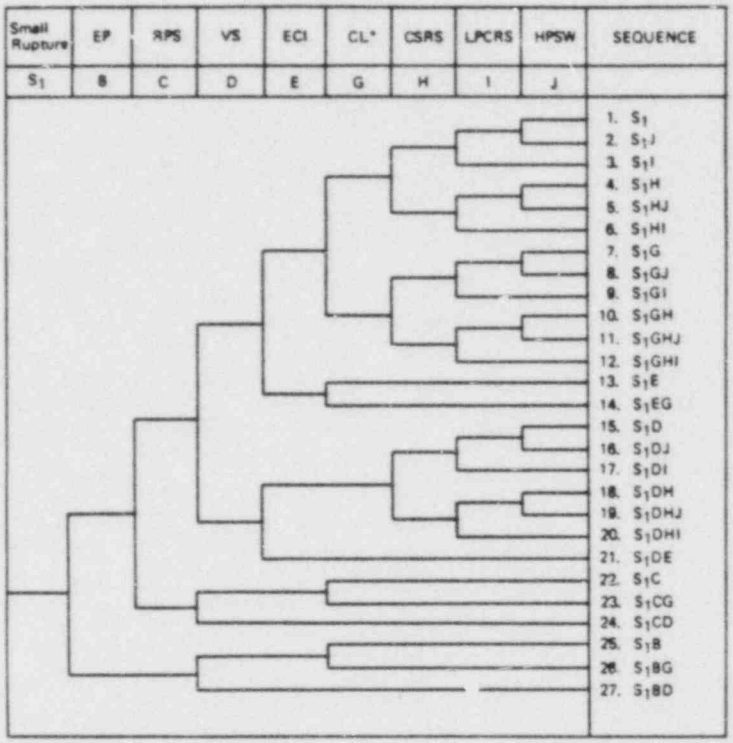


Figure 4-2. Grand Gulf Transient Event Tree



*leakage less than 100%/day

Figure 4-3. Peach Bottom Large LOCA Event Tree



*Containment Leakage less than 100%/day.

Figure 4-4. Peach Bottom Small LOCA (S_1) Event Tree

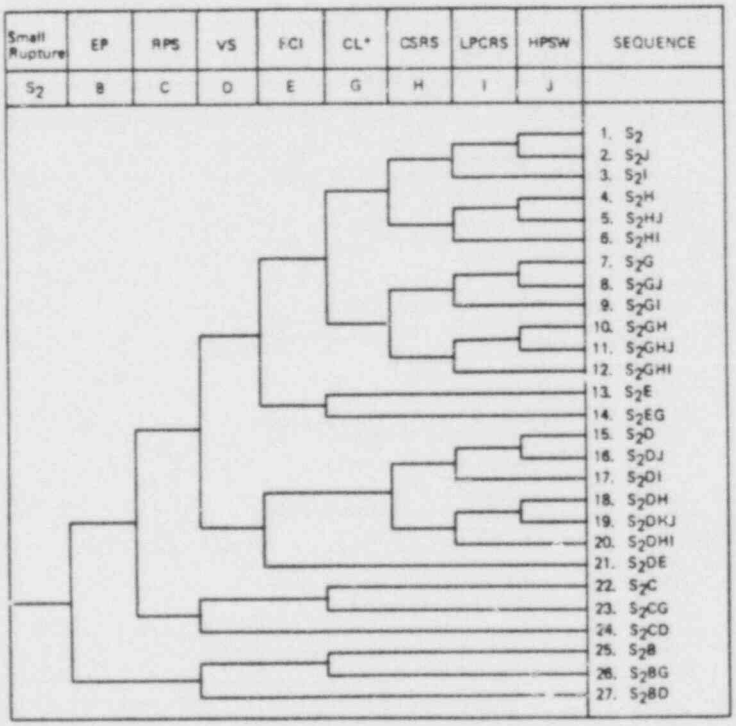


Figure 4-5. Peach Bottom Small LOCA (S_2) Event Tree

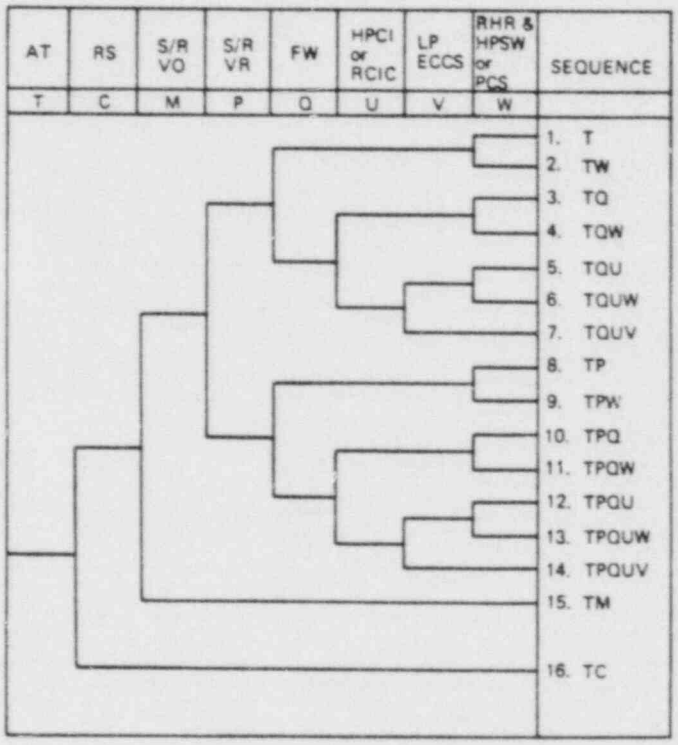


Figure 4-6. Peach Bottom Transient Event Tree

5.0 ACCIDENT PROCESS ANALYSIS TASK

This chapter summarizes the results of the accident processes and source term evaluation for hypothesized core meltdown accidents in the Grand Gulf BWR.

5.1 Scope

The accident processes task is aimed at quantitatively describing the physical phenomena that are expected to occur during reactor meltdown accidents and at determining the nature and quantities of fission products that would be expected to be released from containment during the various accident sequences. The principal physical processes and accident parameters of concern are:

a) the time scale of the accident, particularly the times for the start and completion of core melting,

b) the time required for the molten core to fail the reactor vessel bottom head,

c) possible energetic interactions with water when the core debris falls to the floor of the reactor cavity, including the likelihood of containment failure due to such interactions,

d) long-term pressure-time history within the reactor containment, including the likelihood and timing of containment failure due to overpressure,

e) the probability and consequences of hydrogen burning or detonation within the containment building,

f) the interaction of the core debris with the concrete foundation,

g) the magnitude and timing of fission product release from the fuel to the containment atmosphere,

h) the transport and removal of the various fission product species in the containment building, and

i) time-dependent leak rate from the containment building, including the airborne fission products.

The analyses were conducted with the MARCH and CORRAL computer codes. MARCH performs a consistent analysis of the thermal hydraulics associated with the successive stages of core meltdown and containment response. It represents a significant improvement over the methods of meltdown analysis used previously. CORRAL describes fission product transport and deposition within the containment and determines the leakage to the environment. Much of the input required by CORRAL is provided by MARCH. The current version of CORRAL is a modification and generalization of the CORRAL code developed during the Reactor Safety Study. The MARCH code is described in Reference 6. The general features of the CORRAL code are described in References 2 and 7.

5.2 Containment Processes and Accident Sequence Selection

5.2.1 Containment Event Tree

The containment event tree used in the Grand Gulf evaluation is shown in Figure 5-1, with the notation given in Table 5-1. This containment event tree is much simpler than the BWR containment event tree derived for the Reactor Safety Study; it is, in fact, very similar to the Reactor Safety Study PWR containment

event tree. Some of the reasons for the use of the simplified containment event tree are discussed below.

In the WASH-1400 BWR containment analyses, much attention was devoted to the possible influence on accident behavior of containment isolation failures. If containment isolation failures were significant, then the possible roles of the Secondary Containment and the Standby Gas Treatment System need also be considered. Further, the layout of the MARK I pressure suppression containment led to the possibility that isolation failures in the drywell and wetwell could lead to different consequences. All of the above factors are covered by the RSS BWR containment event tree. Upon completion of the Reactor Safety Study analyses it was clear that none of these factors had a significant influence on the calculated overall accident risk. Thus, the role of possible containment isolation failures is not considered significant in the context of the present study and thus was not explicitly evaluated.

The MARK I containment considered in the Reactor Safety Study was inerted; thus, hydrogen burning was not a significant consideration. The MARK III containment is not inerted and the possible role of hydrogen burning must be included in the evaluation. As was the case with the RSS BWR, containment meltthrough is not expected to be a primary mode of containment failure for meltdown accidents in the MARK III containment due to the predominance of overpressure failure modes; thus, this mode is not shown on the containment event tree. The above considerations led to the use of the simplified containment event tree of Figure 5-1.

5.2.2 Containment Failure Pressure

The Grand Gulf reactor employs the MARK III BWR containment concept. The MARK III consists of an inner drywell connected to a surrounding containment through a pressure suppression pool. Refer to Figure 5-2. The containment cylindrical wall, dome, and foundation mat are constructed of cast-in-place, conventionally reinforced concrete. The containment wall is a right circular cylinder, 3.5 ft thick, with an inside radius of 62.0 ft and a height of 144.75 ft from the top of the foundation mat to the springline. The main reinforcement in the wall consists of inside and outside layers of hoop reinforcement, outside vertical reinforcement, and two orthogonal layers of diagonal reinforcement. The dome is a hemispherical shell, 2.5 ft thick, with an inside radius of 62.0 ft. The main reinforcement in the dome consists of two outside face families of reinforcement which are perpendicular to each other and which are a continuation of the outside face vertical reinforcement in the shell. The containment wall, dome, and associated internal structures are founded on a circular mat, 9.5 ft thick, with an outside diameter of 134.0 ft. The foundation mat has two layers of horizontal reinforcement as well as vertical shear reinforcement. The internal surface of the containment is completely lined with welded steel plate to form a leak-tight barrier.

The inner drywell consists of four major components: a flat, reinforced concrete foundation which is part of the containment foundation; a right vertical cylindrical section, the lower part of which consists of concentric stiffened steel shells with the annulus filled with concrete, and the upper part is a reinforced

concrete cylinder; a flat horizontal reinforced concrete roof containing a circular opening; and the drywell head which is a short stainless steel cylinder with an elliptical head. The drywell is designed as a temporary pressure retention boundary which separates the reactor primary system from the suppression pool and the containment. In the event of the release of primary coolant, the drywell channels it around the weir wall and through the horizontal vents into the suppression pool, thus minimizing the energy release to the containment.

Some of the principal design parameters for the containment building are as follows:

Inside Diameter	124 ft
Inside Height	206.8 ft
Vertical Wall Thickness	3.5 ft
Dome Thickness	2.5 ft
Foundation Slab Thickness	9.5 ft
Liner Thickness	0.25 inch
Free Volume	1,670,100 ft^3
Drywell	270,100 ft^3
Wetwell	1,400,000 ft^3
Containment Design Pressure	15 psig
Drywell Design Pressure	30 psig
Suppression Pool Volume	171,625 ft^3
Suppression Pool Temperature	101°F

In the absence of detailed information on the sizing and placement of reinforcing in the structure and given the limited scope of the study, it was not possible to perform a detailed

analysis of the structure to define an expected failure level. In addition to substantial detail on the design of the structure such an analysis would require consideration of the as-built condition of the structure, knowledge of actual material properties, consideration of plastic as well as elastic behavior, etc. The safety factors inherent in the codes governing the design of structures of the type considered imply that the yield strength of the principal reinforcing may be approached at internal pressures above 1.5 times the design level. The Grand Gulf containment design has apparently adopted a safety factor of two on the yield of the principal reinforcing. Allowance for the strength of the liner as well as actual rather than minimum design basis materials strengths would increase the actual safety factors. Local variations in either material strengths or as-built versus design conditions could, on the other hand, tend to reduce the available factors of safety. Loading of the principal reinforcement to its ultimate strength would imply internal pressures well over twice the design level. It is questionable, however, whether the ultimate strength of the reinforcing can ever be achieved. The reinforcing steel relies on the containment liner and the concrete matrix for the distribution and transmittal of the loads resulting from internal pressures. The high strains inherent at stresses above yield would imply significant cracking and/or spallation of the concrete; if the concrete separates from the steel reinforcing, failure of the structure will take place without developing the full strength of the reinforcing steel. Tearing of the liner may lead to functional failure of the structure even if the reinforcing has not failed.

While the liner is expected to be much more ductile than the rest of the structure, its successful performance at loadings much beyond design cannot be assumed. Considering the design basis for the structure, requisite proof tests, as well as earlier analyses of containments of this type, the nominal failure level for the purposes of this study was taken to be two times the design level, or an internal pressure of 45 psia.

As utilized here, the failure pressure is not a single discrete value, but a continuous variable with a cumulative probability distribution. This approach recognizes that the probability of structural failure is small at loads slightly above design, but increases with increasing loading. By definition, the probability of failure at the nominal failure pressure is 0.5; it approaches unity as the stresses due to the loading approach the ultimate strength of the materials. Under this approach, a failure pressure of 45 $\pm$ 5 psia has been selected for the purposes of this study.

5.2.3 Accident Sequences Considered

Accident event trees have been developed by the Systems Analysis Task for LOCAs (A,S) as well as transients (T_1, T_{23}). Based on the preliminary evaluation of the event trees and the potential consequences of the various sequences, a number of accident sequences were identified as being potentially important with regard to overall accident risk. This set of accident sequences, identified in Table 5-4, was examined in more detail. The results of these analyses formed the basis for the conclusions of this study. A number of these potentially important sequences were explicitly evaluated by means of MARCH and CORRAL calculations, others were

evaluated on the basis of similarity with sequences previously evaluated, still others were considered on the basis of insights developed as a result of related analyses on other reactor designs.

5.3 Analyses of Accident Processes

The MARCH (Meltdown Accident Response CHaracteristics) code provides the analysis of the various thermal-hydraulic processes during reactor meltdown accidents. MARCH contains a number of interrelated and coupled subroutines each of which treats a particular process or phase of the accident. The principal subroutines are noted below. PRIMP evaluates the primary coolant system response including the pressure history and the coolant leakage. Models for secondary system heat transfer for PWRs and emergency core cooling system operation are incorporated in BOIL. These features are essential for the analysis of small break and transient accident sequences. BOIL is the only element of MARCH that was available at the time of the Reactor Safety Study. The initial versions of BOIL described the boiloff of water from the reactor vessel and the meltdown of the core up to the point of core support failure; they assumed a large LOCA as the initiating event. The current version of BOIL provides continuous transitions for core collapse, grid plate failure, and the dropping of the core debris into the lower head of the reactor vessel; a number of user selected options are provided for these transitions. HEAD evaluates failure of the reactor vessel head considering meltthrough as well as the effects of pressure stress; the latter can have a significant effect in

small break and transient sequences. The HOTDROP subroutine describes the interaction of the core debris with water in the reactor cavity following vessel meltthrough, including such effects as debris fragmentation, heat transfer, and chemical reactions. The interaction of the core debris with concrete is described by the INTER code [Reference 8]; the latter was written at Sandia National Laboratories and has been adapted and integrated by BCL into MARCH. The FPLOSS routine describes the release of the radionuclides from the fuel and partitions the heat source between the groups of fission products. The MACE routine describes the containment temperature and pressure history taking into account nuclear heat generation, hydrogen burning, heat losses to structures, effects of containment safeguards, intercompartment flows, leakage to the outside, etc. MACE is continuously coupled to the other subroutines in MARCH. It may be noted that the MACE subroutine in MARCH provides the essential containment thermal-hydraulic input required in CORRAL, the fission product transport code to be discussed later.

5.3.1 Results of the MARCH Analyses

The results of the MARCH analyses of the key accident sequences are summarized in Table 5-2. As can be seen, not all the accident sequence-containment failure mode combinations were evaluated. However, a sufficient number of cases were evaluated in detail to develop an overall insight on expected phenomena in the sequences of interest. Some general observations on the MARCH results are given below. Further discussion of the MARCH calculations is given in Appendix C. The accidents initiated by pipe ruptures

were divided in the Systems Analysis Task into two categories according to the size of the initiating primary system break. A classification of this type was required because the probability of occurrence varies with the size of the break and also because the specific engineered safety features required to cope with the LOCA are a function of the size of the break. LOCAs due to breaks larger than 13.5 inches in diameter were classified as large (A) and those resulting from breaks smaller than 13.5 inches in diameter as small (S). Transients involving stuck-open safety/relief valves, such as sequence TPQI, were modeled in the MARCH calculations as small (5.5 inch diameter) breaks in the steam dome area of the reactor vessel. The transients with correctly functioning safety/relief valves were modeled assuming constant pressure boiloff through cycling relief valves.

The effect of break size or leakage rate on the accident timing for sequences involving no coolant makeup can be seen from the results in Table 5-2 for the AE, TPQE, and TQUV sequences. For the large LOCA, core uncovery occurs at one minute, for the open relief valve at 32 minutes, and for the transient at 75 minutes. Sequences involving failure of the decay heat removal system (Events I and W) develop very slowly. As seen in Table 5-2, core uncovery and melting does not start until elapsed times of 16-34 hours, depending on the assumptions regarding ECCS pump failure.

Comparison of the TQUV-γ and -δ sequences indicates that hydrogen burning can result in containment failure several hours earlier than would otherwise occur. Comparison of the TQW-δ and

AC-δ sequences shows the dependence on core power level of the effectiveness of the suppression pool as a heat sink. For the TQW sequence containment failure is delayed for 30 hours even though the decay heat removal systems are inoperative. For the AC case, overpressure occurs at 23 minutes because the core power level (30 percent) is much greater than the RHR capacity.

5.3.2 Containment Failure Modes

The consideration of the possibility of containment rupture due to steam explosions in the reactor vessel (α) is largely based on the analyses that were conducted for the Reactor Safety Study, with some modification to take into account subsequent experimental work. Based on a large body of experimental evidence resulting from work at ANL, Sandia, and others [References 3 and 4], the occurrence of steam explosions in the presence of a high ambient pressure is believed to be very unlikely. High primary system pressures during the core melting phase are predicted primarily for the transient (T) sequences in which the safety/relief valves reclose. In these situations the probability of α, containment failure due to a steam explosion in the reactor vessel, is taken as 0.0001. In the absence of high pressure, the α probability is the same as that used in the Reactor Safety Study, namely 0.01. The differences in design between Grand Gulf and the Reactor Safety Study reactors are not expected to have any appreciable influence on the effects of a steam explosion if it does take place.

Containment leakage (β) results from the failure to isolate, in the event of an accident, containment penetrations that

are normally open. None of the sequences involving containment isolation failure were found to be among the dominant ones in the Reactor Safety Study and the same situation is assumed to prevail for the Grand Gulf design. This is a result of the combination of low probability of these sequences together with relatively modest consequences associated with them. As a result of these considerations, no containment isolation failure sequences were explicitly evaluated during this study.

The potential for containment rupture due to hydrogen burning (γ) depends on a number of factors, namely:

a) composition of the atmosphere,

b) availability of an ignition source, and

c) incremental pressure rise associated with the burning.

MARCH analyses indicate that flammable compositions will generally be achieved towards the end of core meltdown and will persist thereafter. Frequently the conditions will be more conducive for hydrogen burning in the containment than in the drywell. This is a consequence of the lower partial pressure of steam in the containment as well as the tendency of much of the oxygen and hydrogen to be swept into the containment during the accident. There may, in fact, be periods during the course of the accident when the drywell atmosphere is inerted, either due to insufficient oxygen or due to a high partial pressure of steam. Such conditions tend to be only temporary, however.

The question of availability of an ignition source for hydrogen burning can have several aspects. The hydrogen generated during the core melting process will generally be at a very high

temperature. If the path from the core to the containment atmosphere is short, the hydrogen may be above the spontaneous ignition temperature upon release to the containment and no other ignition source will be required to produce burning assuming that adequate oxygen is available at the point of release. If, on the other hand, the hydrogen passes through a substantial length of piping before reaching the containment, it may be cooled to the point where an external ignition source would be required to produce burning. In transient-initiated accident sequences the hydrogen would be cooled by bubbling through the suppression pool before release to the containment. The dropping of the core debris onto the concrete in the reactor cavity appears to be a particularly likely time for the initiation of hydrogen burning. In experimental studies of large scale melt-concrete interactions, such as conducted at Sandia and the Germany company, Kernforschungszentrum Karlsruhe, hydrogen burning is generally observed to accompany these interactions. Some points of qualification regarding the application of these experimental observations to the analyses of specific accident sequences should be noted. The experiments were conducted in a normal atmosphere with an essentially unlimited supply of oxygen (air); this is clearly not the case in a closed containment where the quantity of air is limited and where the partial pressure of steam may be considerable. Also, in some of the meltdown accident sequences considered, there will be water in the reactor cavity at the time that the core debris are introduced; the effects of this water or the resulting steam on ignition behavior are unknown. For purposes of the MARCH analyses, ignition was assumed to occur

after head failure, provided the composition of the atmosphere was determined to be flammable.

The incremental pressure rise associated with hydrogen burning will depend on the composition of the atmosphere at the time of ignition and the extent of burning, among other factors. Should ignition take place when flammable compositions are first achieved and continue, only relatively modest pressure increases would result. If, however, the concentration of hydrogen is well into the flammable range before ignition, substantial pressure increases can result. Given the preceding assumption that ignition occurs at the time of vessel failure, the concentrations of hydrogen are usually quite high and substantial pressure increases are predicted. The question of the extent of burning involves considerations of both the fraction of the available hydrogen that is consumed as well as the total volume that is affected by the burning. For lean hydrogen-air mixtures, there is the possibility of incomplete combustion; for mixtures well into the flammable range, complete combustion can be expected. The extent of combustion can, however, be controlled by the availability of oxygen. The portion of the containment volume that experiences hydrogen burning is particularly significant in the context of the Grand Gulf containment design. If the entire containment volume undergoes a rapid burn, the resulting pressures would be well in excess of expected failure levels. If the burning is confined to the drywell volume, on the other hand, the resulting overall pressures would be modest. As indicated in the foregoing discussion, for the purposes of this study, the

most likely source of hydrogen ignition was taken to be the dropping of the hot core debris onto the concrete in the reactor cavity; this is not meant to preclude the existence of other sources of ignition, however. Under this assumption, the development of pressures sufficient to fail containment would imply the propagation of the burn from the drywell to the containment. The availability of alternate ignition sources within the containment volume could also lead to the same consequences, but the timing of the occurrence of the latter cannot be defined.

5.4 Fission Product Release Evaluation

The fission product release model used in the present analyses is the same as that used in the Reactor Safety Study. The model consists of four fission product release terms for each of seven classes of fission product species; additionally, a fraction of iodine, one of these species, can be specified as being converted to organic iodine. The release terms and classes of fission products are noted in the discussion below; the basis for and details of this model are given in Reference 2.

5.4.1 CORRAL Code

The CORRAL (Containment of Radionuclides Released After LOCA) code describes fission product transport and deposition in containment systems of water cooled reactors. CORRAL II (Reference 7), the version used here, is a revised and generalized version of the program written for the Reactor Safety Study (Reference 2). The containment is represented by up to fifteen individual compartments connected to each other in any combination

of series or parallel arrangements. Radionuclide release into the containment by any of four release mechanisms for each of eight groups of fission products can be specified. The four release mechanisms are: gap (cladding rupture) release, fuel melting, fission product vaporization, and steam explosion (oxidation) release. The eight groups of radionuclides considered are: noble gases, molecular iodine, organic iodine, cesium-rubidium, tellurium, barium-strontium, ruthenium, and lathanum. Radionuclides can be removed from the atmosphere by particle settling, deposition, spray removal, pool scrubbing, filters, etc. Input requirements for CORRAL include: description of the containment system, engineered safeguards parameters, timing of accident events, thermodynamic conditions as a function of time, intercompartment flows, leakage rates, and fission product release component fractions. The code uses this input to continuously compute changing properties and fission product removal rates as a function of time. These values are used in incremental solutions to the coupled set of differential equations to obtain the time dependent fission product concentrations and accumulations in each compartment of the containment. The principal output consists of cumulative fractional releases from containment with time for each of the fission product groups.

5.4.2 Grand Gulf Modeling

For the CORRAL as well as for the MARCH analyses, the Grand Gulf MARK III pressure suppression containment was modeled as a two compartment system. For the LOCA sequences, the fission products were released to the drywell atmosphere and transported

through the suppression pool into the containment volume according to the intercompartment flow rates as predicted by MARCH. For the transient-initiated sequences, the gap and melt fission product releases were released directly to the suppression pool via the safety/relief valve discharge headers; the vaporization releases which take place following reactor vessel failure went into the drywell. Since neither MARCH nor CORRAL contains models for the evaluation of fission product scrubbing by suppression pools, the appropriate decontamination factors must be provided as input. Constant decontamination factors of 100 for molecular iodine and particulates were utilized in conjunction with flows through condensing (subcooled) pools. No credit for fission product scrubbing was taken for flows through saturated and/or boiling pools. In the absence of condensation, fission product bearing vapor and/or gas bubbles would present relatively little opportunity for the fission products to contact the liquid, particularly if the bubbles are growing in volume as they rise through the pool. Also, no fission product scrubbing by the pool was considered following containment failure. The latter assumption could be overly conservative for situations where the pool is maintained subcooled. However, due to the uncertainties associated with the potential modes of containment failure, the potential for damage to the drywell-containment interface, possibility of displacement of pool water so as to uncover the vents, etc., this assumption is considered reasonable for purposes of this study. The suppression pool is assumed to have no effect on noble gases or organic iodine. The overall treatment of

fission product removal by the suppression pool in the present study is consistent with that used in the Reactor Safety Study.

5.4.3 Results of the CORRAL Analyses

The results of the CORRAL calculations are summarized in Table 5-3. The results of the specific CORRAL cases presented here were used to estimate the release fractions for other similar sequences that were not evaluated in detail. This is similar to the approach used in the Reactor Safety Study.

5.5 Summary and Discussion of Results

The combined results of the MARCH and CORRAL analyses of the Grand Gulf BWR key accident sequences are summarized in Table 5-4. Given here for each of the previously identified important accident sequences are applicable containment failure modes and the estimated release category for each accident sequence-failure mode combination. Also shown are the estimated probabilities of the various containment failure modes for each sequence. The BWR release categories assumed here are the same as those defined in the Reactor Safety Study. Only the four core melt categories are considered. It may be noted, however, that in many cases the specific fission product releases calculated in the present study did not correspond very closely to the previously defined release categories. This may suggest the need to reevaluate the definition of the Reactor Safety Study release categories and consider the establishment of alternate and perhaps more generally applicable categories, if the use of this concept is continued.

5.5.1 Assignment to Release Categories

From Table 5-4 it is seen that all the steam explosion (α) cases for Grand Gulf are estimated to fall into Release Category 1. The steam explosion cases are characterized by containment failure occurring near the end of the core melting phase and a large release of the ruthenium group of fission products resulting from air oxidation of the fuel. This is consistent with the results of the Reactor Safety Study.

While no detailed MARCH and CORRAL calculations of these cases were performed, the containment isolation (β) sequences would be expected to lead to BWR Category 4 releases. There could be significant variation in the actual magnitudes of release, depending on the nature of the isolation failures. For example, isolation failures that could bypass the suppression pool could lead to higher releases than those in which the fission products passed through the pool.

For sequences involving containment failure due to hydrogen burning (γ) the releases were found to correspond to BWR Category 3 under the assumptions of this study. It will be recalled that hydrogen burning was assumed to take place following reactor vessel failure. Thus, typically, the melt component of the fission product release would be reduced due to pool scrubbing prior to containment failure, while the subsequent vaporization release did not undergo pool scrubbing. Should the suppression pool be effective for fission product removal following containment failure, or if hydrogen burning were delayed significantly after the time of vessel failure, the radioactivity release to the environment would be reduced to BWR Category 4.

The magnitude of the releases associated with containment overpressure (δ) failures are sensitive to the timing of containment failure relative to core melting. Because of this, several accident sequences involving inadequate long term residual heat removal (e.g., TPQI, TQW, SI, AI, and others) were analyzed twice using different phenomenological assumptions.

One scenario is where the ECCS pumps fail during the residual heat removal phase due to elevated suppression pool water temperatures. The ECCS pumps are designed to operate up to 212°F and, therefore, might fail at the higher temperatures expected for certain accidents. In this case, core melt would occur prior to containment failure by overpressure. This is important because core melting in an initially intact containment results in smaller releases since airborne fission products will generally be reduced due to pool scrubbing and natural deposition processes. If containment failure occurs near the time of reactor vessel failure, the resulting radioactivity releases will correspond to BWR Release Category 3 releases. If the containment failure is delayed several hours after the start of the core debris/concrete interaction, the resulting releases would correspond to BWR Release Category 4. These delayed containment failures are due to the continued buildup of noncondensables from the decomposition of concrete and imply low suppression pool temperatures and effective fission product scrubbing.

A second scenario was analyzed where the ECCS pumps do not fail due to elevated suppression pool water temperatures. For this case, ECCS failure and subsequent core melt would be expected

after the overpressure containment failure. The containment blowdown after failure causes the suppression pool to flash and boil resulting in ECCS pump cavitation and core melt. When fission products are released into a failed containment, no credit was given to the suppression pool for fission product removal and BWR Release Category 2 releases are predicted.

Results for both of these scenarios are given for various sequences in Table 5-4. In the analysis of the dominant accident sequences presented in Chapter 6, only the results for the second scenario are used. Current information suggests that the ECCS pumps will not fail due to elevated suppression pool water temperatures during sequences involving inadequate residual heat removal.

5.5.2 Quantification of Containment Failure Modes

The quantification of the steam explosion probabilities was discussed previously. Basically, the reference steam explosion probabilities are unchanged from the results of the Reactor Safety Study. For core melting at high ambient (primary system) pressure, the probabilities of steam explosions failing containment have been reduced on the basis of the results of several experimental programs conducted since the time of the Reactor Safety Study.

The probability of containment isolation failure (β) was estimated to be approximately .007. It was assumed that the Mark III containment leakage paths would be no worse than those found at a large, dry PWR such as the Oconee reactor. Both have atmospheric containments with no constant monitoring system to detect containment leakage. Therefore, a .007 containment leakage

probability was assessed for Grand Gulf based on the value calculated for Oconee (Reference 9). From the Reactor Safety Study, it was expected that sequences involving containment isolation failure would not significantly contribute to the overall risk. Thus, further definition of the probability of containment isolation failure was not warranted.

The probability of containment failure due to hydrogen burning (γ) depends almost entirely on the occurrence of burning in the containment (wetwell) volume. It may be noted that the question of hydrogen burning is of concern primarily in those sequences in which core melting takes place in an initially intact containment. Burning in the containment could take place either due to propagation of burning from the drywell or from ignition sources in the containment itself. Hydrogen burning in the drywell is believed to be highly likely, with the time of vessel failure being perhaps the most obvious time for the initiation of burning. The potential for burning propagation from the drywell to the containment will depend in part on available leak paths between the two compartments. Ignition in the containment volume, independent of the events in the drywell, can conceivably occur at any time (given, of course, the existence of flammable compositions). MARCH calculations indicate that containment conditions favorable to hydrogen burning may exist for prolonged periods of time. Thus, the probability of ignition must be considered high. For the purpose of quantifying the

results of this study, the probability of hydrogen burning failing containment (γ) is estimated to be 0.5. This value is highly judgmental and subject to considerable uncertainty.

The probability of containment overpressure failure (δ) appears to be highly likely for core meltdown accidents if the other modes of containment failure are avoided. For the relatively low design pressure of the MARK III containment, the buildup of noncondensables generated during the course of core meltdown accidents will likely exceed the containment pressure capability. As was noted in an earlier discussion, the timing of the overpressure failure may vary with the accident sequences considered. For sequences involving loss of containment heat sink and no recovery, containment failure must be considered inevitable. This is reflected in the containment failure mode probabilities in Table 5-4. Generally speaking, however, the timing of the containment failure, and hence the time available for recovery, will depend on the pressure assumed to cause containment failure.

Table 5-1. Containment Event Tree Notation

Symbol	Letter	Meaning
CRVSE	α	Containment rupture due to a reactor vessel steam explosion
CL	β	Containment leakage
CR-B	γ	Containment rupture due to hydrogen burning
CR-OP	δ	Containment rupture by over-pressurization

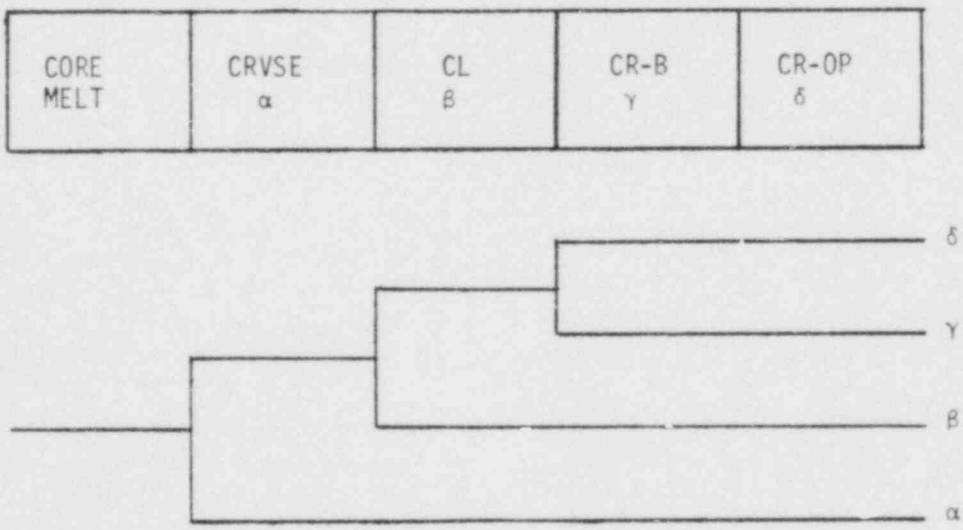


Figure 5-1. Containment Event Tree

Table 5-2. Summary of MARCH Accident Event Times[1]

Sequence	ECC Start	ECC Stop	Cont. Failure[2]	Core Uncovery	Core Melt Start	Core Melt End	Head Failure	Description
TPQI-δ[3][6]	1	779	1192	1055	1124	1192	1344	Stuck-open safety valve, no decay heat removal
TQW-δ[3]	1	980	1340	1186	1255	1326	1340	Transient, no decay heat removal
TQW-δ[4]	1	1800	1800	2039	2133	2220	2234	Transient, no decay heat removal
TQUV-δ	0	0	401	75	106	142	154	Transient, no ECC
TQUV-γ	0	0	154	75	106	142	154	Transient, no ECC
TPQE-δ	0	0	540	32	71	110	136	Open valve, no ECC
AE-[illegible]	0	0	252	1	13	54	78	Large LOCA, no ECC
TC-δ[5]	1	26	417	5	26	78	90	Transient, scram failure
TC-δ[4]	1	71	71	71	92	144	166	Transient, scram failure
AC-δ[4]	1	23	23	25	47	103	133	Large LOCA, scram failure

(1) Times are in minutes.
(2) For a containment failure pressure of 45 psia.
(3) Assuming ECC fails due to high suppression pool temperature (>212°F).
(4) Assuming ECC fails at time of containment overpressure failure. This assumption was used in the final analysis.
(5) Core uncovery and melt due to insufficient makeup; ECC stopped at start of melt.
(6) The anticipated containment failure time for TPQI sequences where the ECCS fails at the time of containment failure is 1652 minutes. This time was used in the recovery factor incorporated into TPQI cut sets in Chapter 6.

Table 5-3. Summary of CORRAL Results, Final Releases

Case	Fission Product Group							Estimated Release Category	Foot-notes
	Xe	I	Cs	Te	Ba	Ru	La		
TPQI-δ	1.0	0.57	0.52	0.31	0.058	0.030	0.0044	BWR 2	(1)
TQW-δ	1.0	0.21	0.58	0.55	0.063	0.044	0.0072	BWR 2	(1)
AC-δ	1.0	0.50	0.67	0.25	0.080	0.032	0.0039	BWR 2	(1)
TQUV-γ	1.0	0.033	0.17	0.49	0.014	0.030	0.0058	BWR 3	(2)
TQUV-δ	1.0	4.4-4	6.2-3	0.016	5.1-4	9.8-4	1.9-4	BWR 4	(3)
	WASH-1400 Release Categories								
----	1.0	0.4	0.4	0.7	0.05	0.5	0.005	BWR 1	
----	1.0	0.9	0.5	0.3	0.1	0.03	0.004	BWR 2	
----	1.0	0.1	0.1	0.3	0.01	0.02	0.003	BWR 3	
----	0.6	8.0-4	5.0-3	4.0-3	6.0-4	6.0-4	1.0-4	BWR 4	
----	1.0	1.0	1.0	1.0	0.11	0.08	0.013	Fission Product Source Term	

(1) No scrubbing of fission products assumed due to high suppression pool temperature.

(2) Containment failure due to hydrogen burn at head failure; gap and melt release scrubbed by pool; no fission product scrubbing by pool after containment failure.

(3) Cold suppression pool; containment failure delayed 4 hrs. after head melting; fission products scrubbed by pool.

Table 5-4. Accident Sequence Containment Failure Mode Probabilities And Release Categories

Sequence	Release Category 1	2	3	4
$AI^{(1)}$	$\alpha=0.01$		$\gamma+\delta=1$	$\beta=0.007$
$AI^{(2)}$	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
AE	$\alpha=0.01$		$\gamma+\delta^{(3)}=0.8$	$\delta=0.2$
$AC^{(1)}$	$\alpha=0.01$		$\gamma+\delta=1$	$\beta=0.007$
$AC^{(2)}$	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
ADI	$\alpha=0.01$	$\delta=1$		
ADE	$\alpha=0.01$	$\delta=1$		
ACD	$\alpha=0.01$	$\delta=1$		
$SI^{(1)}$	$\alpha=0.01$		$\gamma+\delta=1$	$\beta=0.007$
$SI^{(2)}$	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
$SC^{(1)}$	$\alpha=0.0001$		$\gamma+\delta=1$	$\beta=0.007$
$SC^{(2)}$	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
SE	$\alpha=0.01$		$\gamma+\delta^{(3)}=0.8$	$\delta=0.2$
SDI	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
SCD	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
SDE	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
$T_1PQI^{(1)}$	$\alpha=0.01$		$\gamma+\delta=1$	$\beta=0.007$
$T_1PQI^{(2)}$	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
T_1PQE	$\alpha=0.01$		$\gamma=0.5$	$\delta=0.5$
$T_{23}PQI^{(1)}$	$\alpha=0.01$		$\gamma+\delta=1$	$\beta=0.007$
$T_{23}PQI^{(2)}$	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
$T_{23}PQE$	$\alpha=0.01$		$\gamma=0.5$	$\delta=0.5$

Table 5-4. Accident Sequence Containment Failure Mode Probabilities And Release Categories (Continued)

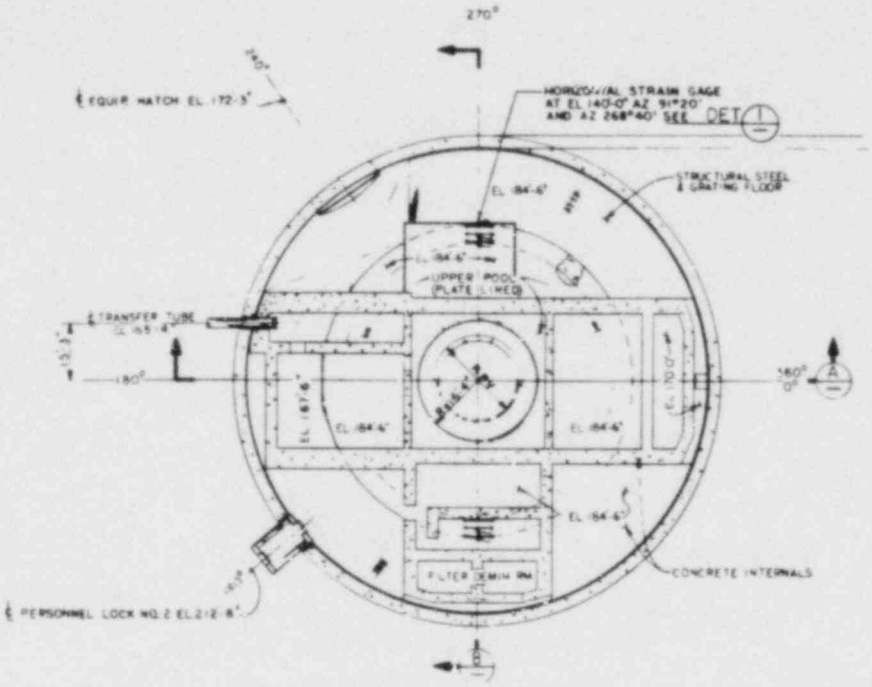
Sequence	Release Category 1	2	3	4
$T_1QW^{(1)}$	$\alpha=0.0001$		$\gamma+\delta=1$	$\beta=0.007$
$T_1QW^{(2)}$	$\alpha=0.0001$	$\delta=1$		$\beta=0.007$
T_1QUV	$\alpha=0.0001$		$\gamma=0.5$	$\delta=0.5$
$T_1C^{(4)}$	$\alpha=0.0001$		$\gamma+\delta=1$	$\beta=0.007$
$T_1C^{(2)}$	$\alpha=0.0001$	$\delta=1$		$\beta=0.007$
$T_1QUW^{(1)}$	$\alpha=0.01$		$\gamma+\delta=1$	$\beta=0.007$
$T_1QUW^{(2)}$	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
$T_{23}C^{(4)}$	$\alpha=0.0001$		$\gamma+\delta=1$	$\beta=0.007$
$T_{23}C^{(2)}$	$\alpha=0.0001$	$\delta=1$		$\beta=0.007$
$T_{23}QW^{(1)}$	$\alpha=0.0001$		$\gamma+\delta=1$	$\beta=0.007$
$T_{23}QW^{(2)}$	$\alpha=0.0001$	$\delta=1$		$\beta=0.007$
$T_{23}QUW^{(1)}$	$\alpha=0.01$		$\gamma+\delta=1$	$\beta=0.007$
$T_{23}QUW^{(2)}$	$\alpha=0.01$	$\delta=1$		$\beta=0.007$
$T_{23}QUV$	$\alpha=0.0001$		$\gamma=0.5$	$\delta=0.5$

(1) For ECCS failure due to high suppression pool temperature preceding containment failure.

(2) Assuming ECCS failure due to pump cavitation following containment failure. This scenario was used in the Chapter 6 analysis.

(3) Early overpressure failure resulting from interaction of core debris with water in reactor cavity.

(4) For core melting due to insufficient makeup.



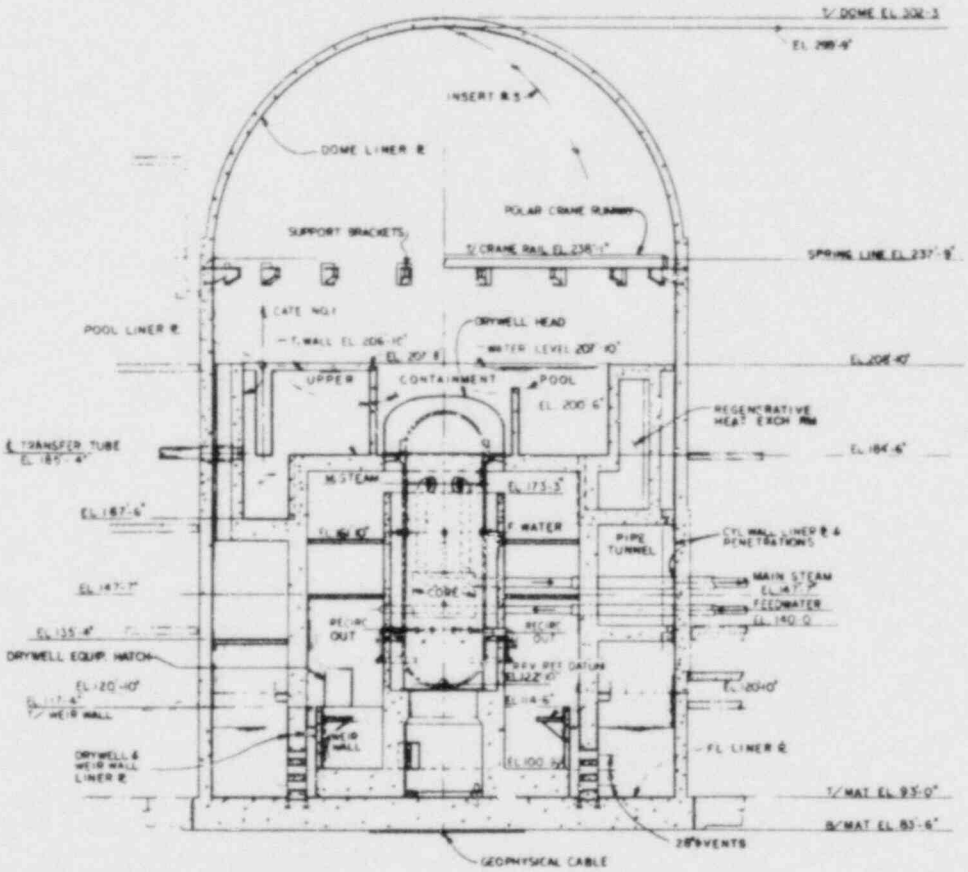


Figure 5-2. Grand Gulf Mark III Containment

6.0 RESULTS

Two of the main objectives of this study were to determine which accident sequences are the most significant contributors to the risk associated with the operation of the Grand Gulf plant and to compare the overall risk for this plant with the comparable RSS BWR. The most significant Grand Gulf accident sequences, or "dominant accident sequences," are discussed in detail in Section 6.1. These sequences were derived by considering both the results of the systems analysis task and accident process analysis task presented in Chapters 4 and 5, respectively. The overall risk of Grand Gulf is indirectly compared with Peach Bottom. This is done by comparing the frequency assessed for the four BWR core melt release categories. The comparison is presented in Section 6.2. In Section 6.3, appropriate conclusions and study limitations are given.

6.1 Grand Gulf Dominant Accident Sequences

The dominant accident sequences identified for the Grand Gulf plant are depicted in Figure 6-1. A key to the figure nomenclature is given in Table 6-1.

The solid lines on the histogram represent the release category frequencies. These were found by summing, for each release category, the point estimate frequencies of the dominant accident sequences and less important sequences not presented in the associated matrix of accident sequences vs. release categories. It should be noted that the dominant accident sequences presented in Figure 6-1 represent greater than 90 percent of the total release category frequency

for categories 1, 2, and 3, and greater than 80 percent for category 4. The dashed lines represent the release category frequencies after application of the RSS curve smoothing technique; that is, a probability of 0.1 was assigned to an accident sequence being in the adjacent release category, and a probability of 0.01 was assigned to an accident sequence being two release categories from the one in which it was placed, etc. The curve smoothing technique reflects the uncertainty associated with the categorization of each accident sequence. As can be noted from the figure, the effect of curve smoothing dominates the frequency estimates for release category 1.

The dominant accident sequences will now be discussed in the order they are displayed in Figure 6-1. For each sequence, several of the most probable cut sets are described. A more complete list of cut sets for each dominant sequence is given in Appendix D. Also, some containment failure modes are not discussed for certain sequences. This was done when sequences were not dominant in a particular category. The systems and cut set terms used to describe the accident sequences are discussed in Appendix B.

It should be noted that all significant double maintenance contributions have been removed from the dominant accident sequence frequencies. These contributions are from maintenance acts involving redundant systems which would violate technical specifications (e.g., simultaneous maintenance of the High Pressure Core Spray and Reactor Core Isolation Cooling System).

Sequence T_1PQI - α, δ:

This sequence is initiated by a loss of offsite power (T_1) followed by a safety/relief valve failing to reseat (P), a failure to restore the Power Conversion System (Q), and a failure of the Residual Heat Removal System to start removing decay heat from the suppression pool within 28 hours (I). Containment failure is predicted to occur from a steam explosion (α) or an overpressure due to gas generation (δ).

When a safety/relief valve fails to reseat and the Power Conversion System is unavailable, reactor decay heat will be deposited in the suppression pool throughout the accident. Failure of the RHRS to remove decay heat from the suppression pool will eventually result in containment overpressure. Decay heat can be removed by either RHRS loop (A or B) operating in the suppression pool cooling mode.

Recovery of the Power Conversion System after a T_1 initiator depends on the restoration of offsite power. This is reflected in the dominant cut sets below by the terms LOPNRE and LOPNRL which together represent nonrecovery of offsite power within approximately 28 hours.

Core melt for this sequence begins sometime after the containment failure at 28 hours. Since this sequence involves long-term failures, a recovery factor was incorporated into the cut sets to reflect restoration from test or maintenance of critical components or other possible corrective actions which could be undertaken to mitigate the accident.

The frequency of this sequence is estimated to be:

$$T_1PQI = 1.6 \times 10^{-6}$$

The dominant contributors, or cut sets, of this sequence are listed and described below.

Cut Set	Cut Set Frequency	Term Description
T_1*P*LOPNRE*LOPNRL*DIESEL1*DIESEL2*RECOVERY	1.2×10^{-7}	T_1 - A transient initiated by a loss of offsite power; $F(T_1) = .2$/R-yr P - Failure of a safety/relief valve to reseat; P(P) = .1 LOPNRE - Nonrecovery of off-site power within one half hour; P(LOPNRE) = .2 LOPNRL - Nonrecovery of off-site power within 28 hours given LOPNRE; P(LOPNRL) = .1 DIESEL2 - Failure of diesel generator #2 to provide emergency power; P(DIESEL2) = 3.6×10^{-2} DIESEL1 - Failure of diesel generator #1 to provide emergency power; P(DIESEL1) = 3.6×10^{-2} RECOVERY - failure to restore maintenance or test faults or take other corrective action within 28 hours; P(RECOVERY) = .23.
T_1*P*LOPNRE*LOPNRL*DIESEL2*VGA2*RECOVERY	7.9×10^{-8}	T_1, P, LOPNRE, LOPNRL, DIESEL2, RECOVERY, (discussed above)

Cut Set	Cut Set Frequency	Term Description
		VGA2 - Valve failure in the RHR heat exchanger bypass line, suppression pool return line, pump room cooling line, or seal cooling line (Train A); P(VGA2) = 2.4×10^{-2}
T_1*P*LOPNRE* LOPNRL*DIESEL1* VGB2*RECOVERY	7.9×10^{-8}	T_1, P, LOPNRE, LOPNRL, DIESEL1, RECOVERY (discussed above)
		VGB2 - Valve failure in the RHR heat exchanger bypass line, suppression pool cooling line, or seal cooling line (Train B); P(VGB2) = 2.4×10^{-2}
T_1*P*LOPNRE* LOPNRL*DIESEL2* SSA*RECOVERY	7.0×10^{-8}	T_1, P, LOPNRE, LOPNRL, DIESEL2, RECOVERY (discussed above)
		SSA - Hardware failure in Standby Service Water System loop A; P(SSA) = 2.1×10^{-2}
T_1*P*LOPNRE* LOPNRL*DIESEL1* SSB*RECOVERY	7.0×10^{-8}	T_1, P, LOPNRE, LOPNRL, DIESEL1, RECOVERY (discussed above)
		SSB - Hardware failure in Standby Service Water System loop B; P(SSB) = 2.1×10^{-2}

The most probable cut sets for this sequence are characterized by nonrecovery of offsite power, which causes the Power Conversion System to be unavailable, and combinations of diesel generator failures or hardware failures which cause the two residual heat removal trains to be unavailable.

The dominant containment failure mode probabilities and release category placements for sequence T_1PQI were assessed to be:

$P(\alpha) = .01$; Category 1

$P(\delta) = 1.0$; Category 2

Multiplying the sequence frequency with the containment failure mode probabilities gives the values presented in Figure 6-1.

Sequence $T_{23}PQI$ - α, δ:

This sequence is initiated by a T_{23} transient followed by a safety/relief valve failing to reseat (P), a failure of the Power Conversion System (Q), and a failure of the Residual Heat Removal System to remove decay heat from the suppression pool within 28 hours (I). Containment failure is predicted to occur from a steam explosion (α) or an overpressure due to gas generation (δ).

When a safety/relief valve fails to reseat and the Power Conversion System is unavailable, reactor decay heat will be deposited in the suppression pool throughout the accident. Failure of the RHRS to remove decay heat from the suppression pool will eventually result in containment overpressure. Decay heat can be removed by either RHRS loop (A or B) operating in the suppression pool cooling mode.

Failure of the Power Conversion System is represented by term Q in the sequence cut sets listed below. Term Q is defined as failure of the Power Conversion System to remove decay heat within approximately 28 hours.

Core melt for this sequence begins sometime after the containment failure at 28 hours. Since this sequence involves long-term

failures, a recovery factor was incorporated into the cut sets to reflect restoration from test or maintenance of critical components or other possible corrective actions which could be undertaken to mitigate the accident.

The frequency of this sequence is estimated to be:

$$T_{23}PQI = 3.7 \times 10^{-6}$$

The dominant contributors, or cut sets, of this sequence are listed and described below. Maintenance contributions which would violate technical specifications have been removed from the following cut set frequencies:

Cut Set	Cut Set Frequency	Term Description
T_{23}*P*Q*VGA2*VGB2*RECOVERY	5.0×10^{-7}	T_{23} - A transient other than a loss of offsite power which requires a reactor shutdown; $F(T_{23})$ = 7/R-yr P - Failure of a safety/relief valve to reseat; P(P) = .1 Q - Failure of the PCS to remove heat within about 28 hours. $P(Q) = 7.0 \times 10^{-3}$ VGB2 - Valve failure in the RHR heat exchanger bypass line, suppression pool return line, pump room cooling line, or seal cooling line (Train B); $P(VGB2) = 2.4 \times 10^{-2}$ VGA2 - Valve failure in the RHR heat exchanger bypass line, suppression pool return line, pump room cooling line, or seal cooling line (Train A); $P(VGA2) = 2.4 \times 10^{-2}$

Cut Set	Cut Set Frequency	Term Description
		RECOVERY - failure to restore maintenance or test faults or take other corrective action within 28 hours; P(RECOVERY) = .23.
T_{23}*P*Q*VGB2*SSA*RECOVERY	3.4×10^{-7}	T_{23}, P, Q, VGB2, RECOVERY (discussed above) SSA - Hardware failure in Standby Service Water System loop A; P(SSA) = 2.1×10^{-2}
T_{23}*P*Q*VGA2*SSB*RECOVERY	3.4×10^{-7}	T_{23}, P, Q, VGA2, RECOVERY (discussed above) SSB - Hardware failure in Standby Service Water System loop B; P(SSB) = 2.1×10^{-2}

The most probable cut sets for this sequence are characterized by unavailability of the Power Conversion System to remove decay heat long term and combinations of hardware failures in the Residual Heat Removal System or Standby Service Water System which prevent the suppression pool from being cooled.

The dominant containment failure mode probabilities and release category placements for sequence T_{23}PQI were assessed to be:

$P(\alpha) = .01$; Category 1

$P(\delta) = 1.0$; Category 2

Multiplying the sequence frequency with the containment failure mode probabilities gives the values presented in Figure 6-1.

Sequence $T_1PQE - \gamma, \delta$:

This sequence is initiated by a loss of offsite power (T_1) followed by a safety/relief valve failing to reseat (P), unavailability of the Power Conversion System (Q), and a failure of emergency core cooling (E). Containment failure is predicted to occur from an overpressure due to rapid hydrogen burning (γ) or an overpressure due to gas generation (δ).

Emergency core cooling can be achieved by the High Pressure Core Spray, the Reactor Core Isolation Cooling System, the Low Pressure Core Spray, or two of three Low Pressure Coolant Injection System trains. Successful low pressure injection requires manual Automatic Depressurization System actuation. It was assumed that system parameters do not reach the automatic ADS initiation setpoints. Failure to inject water into the core following a stuck open relief valve quickly leads to a core melt.

The Power Conversion System (PCS) will be interrupted shortly after a transient of this type and therefore must be recovered to provide coolant injection. The PCS will be interrupted when the Main Steam Isolation Valves (MSIVs) close (MSIV closure on low reactor water level or steam pressure is expected). PCS recovery will depend on: (1) the reopening of the MSIVs, (2) reestablishing the condenser vacuum, if needed, (3) restoration of offsite power (T_1 transients), and (4) switchover to the auxiliary steam supply for the Steam Jet Air Ejectors (which maintain condenser vacuum) when primary steam pressure drops below approximately 150 psia. Since core melt for this sequence begins at 71 minutes and some of the recovery actions take a long time to accomplish (.3 to 2 hours

for getting the MSIVs open according to utility information), no credit was given for the PCS for coolant injection for TPQE sequences.

The frequency of this sequence is estimated to be:

$$T_1PQE = 2.3 \times 10^{-7}$$

The dominant contributors, or cut sets, of this sequence are listed and described below.

Cut Set	Cut Set Frequency	Term Description
T_1*P*Q*H*R*OP	1.1×10^{-8} (see note)	T_1 - A transient initiated by a loss of offsite power; $F(T_1) = .2$/R-yr P - Failure of a safety/relief valve to reseat; $P(P) = .1$ Q - Failure of the PCS to provide makeup water; $P(Q) = 1.0$ H - Hardware failure of the High Pressure Core Spray; $P(H) = 2.1 \times 10^{-2}$ R - Hardware failure of the Reactor Core Isolation Cooling System; $P(R) = 5.1 \times 10^{-2}$ OP - Failure of the operator to manually initiate the Automatic Depressurization System; $P(OP) = 1.5 \times 10^{-3}$
T_1*P*Q*OP*R* LOPNRE*DIESEL3	1.1×10^{-8}	T_1, P, Q, R, OP (discussed above) LOPNRE - Failure to recover offsite power within about one half hour; P(LOPNRE) = .2

Cut Set	Cut Set Frequency	Term Description
		DIESEL3 - Failure of diesel generator #3 to supply emergency power; P(DIESEL3) = 3.6×10^{-2}
T_1*P*Q*LOPNRE* DIESEL1*DIESEL2* DIESEL3*R	9.5×10^{-9}	T_1, P, Q, DIESEL3, R, LOPNRE (discussed above)
		DIESEL2 - Failure of diesel generator #2 to provide emergency power; P(DIESEL2) = 3.6×10^{-2}
		DIESEL1 - Failure of diesel generator #1 to provide emergency power; P(DIESEL1) = 3.6×10^{-2}

Note: Double maintenance contributions (i.e., the HPCS and RCICS being simultaneously out for maintenance) have been removed from this cut set frequency.

The most probable cut sets for this sequence are characterized by hardware failure of the RCICS, hardware or power faults of the HPCS, and failure of the operator to depressure the reactor so that the low pressure injection systems can be available.

The dominant containment failure mode probabilities and release category placements for sequence T_1PQE were assessed to be:

$P(\gamma) = .5$; Category 3

$P(\delta) = .5$; Category 4

Multiplying the sequence frequency with the containment failure mode probabilities gives the values presented in Figure 6-1.

Sequence $T_{23}PQE - \gamma, \delta$:

This sequence is initiated by a T_{23} transient followed by a safety/relief valve failing to reseat (P), a failure of the Power Conversion System (Q), and a failure of emergency core cooling (E). Containment failure is predicted to occur from an overpressure due to rapid hydrogen burning (γ) or an overpressure due to gas generation (δ).

Emergency core cooling can be achieved by the High Pressure Core Spray, the Reactor Core Isolation Cooling System, the Low Pressure Core Spray, or two of three Low Pressure Coolant Injection System trains. Successful low pressure injection requires manual Automatic Depressurization System actuation. It was assumed that system parameters do not reach the automatic ADS setpoints. Failure to inject water into the core after a transient induced LOCA quickly leads to a core melt.

It has been assumed that the Power Conversion System (PCS) will be interrupted shortly after a transient involving a stuck-open relief valve and therefore must be recovered to provide coolant injection. The PCS will be interrupted when the Main Steam Isolation Valves (MSIVs) close (MSIV closure on low reactor water level or steam pressure is expected). PCS recovery will depend on: (1) the reopening of the MSIVs, (2) reestablishing the condenser vacuum, if needed, (3) restoration of offsite power (T_1 transients), and (4) switchover to the auxiliary steam supply for the Steam Jet Air Ejectors (which maintain condenser vacuum) when primary steam pressure drops below approximately 150 psia. Since core melt for this sequence begins at 71 minutes and some of the recovery actions

take a long time to accomplish (.3 to 2 hours for getting the MSIVs open according to utility information), no credit was given for the PCS for coolant injection for TPQE sequences.

The frequency of this sequence is estimated to be:

$$T_{23}PQE = 5.4 \times 10^{-7}$$

The dominant contributors, or cut sets, of this sequence are listed and described below.

Cut Set	Cut Set Frequency	Term Description
T_{23}*P*Q*H*R* OP	3.8×10^{-7} (see note)	T_{23} - A transient other than a loss of offsite power which requires a reactor shutdown; $F(T_{23}) = 7/R\text{-}yr$
		P - Failure of a safety/relief valve to reseat; P(P)=.1
		Q - Failure of the PCS to provide makeup water; P(Q) = 1.0.
		H - Hardware failure of the High Pressure Core Spray; $P(H) = 2.1 \times 10^{-2}$
		R - Hardware failure of the Reactor Core Isolation Cooling System; $P(R) = 5.1 \times 10^{-2}$
		OP - Failure of the operator to manually initiate the ADS; $P(OP) = 1.5 \times 10^{-3}$
T_{23}*P*Q*HACT*R* OP	6.4×10^{-8}	T_{23}, P, Q, R, OP (discussed above)
		HACT - Initiation circuit failure of the High Pressure Core Spray; $P(HACT) = 1.2 \times 10^{-3}$
T_{23}*P*Q*RACT*H* OP	2.6×10^{-8}	T_{23}, P, Q, H, OP (discussed above)

Cut Set	Cut Set Frequency	Term Description
		RACT - Initiation circuit failure of the Reactor Core Isolation Cooling System P(RACT) = 1.2×10^{-3}

Note: Double maintenance contributions (i.e., the HPCS and RCICS being simultaneously out for maintenance) have been removed from this cut set frequency.

The most probable cut sets for this sequence are characterized by hardware and initiation circuit failures of the RCICS and HPCS and failure of the operator to depressurize the reactor so that the low pressure injection systems can be available.

The dominant containment failure mode probabilities and release category placements for sequence $T_{23}PQE$ were assessed to be:

$P(\gamma) = .5$; Category 3

$P(\delta) = .5$; Category 4

Multiplying the sequence frequency with the containment failure mode probabilities gives the values presented in Figure 6-1.

Sequence SI - α, δ:

This sequence is initiated by a small LOCA (S) followed by a failure of the Residual Heat Removal System to remove decay heat from the suppression pool (I). Containment failure is predicted to occur from a steam explosion (α) or an overpressure due to gas generation (δ).

Throughout the LOCA, reactor decay heat will be deposited in the suppression pool. Failure of the RHRS to remove this heat will eventually result in containment overpressure and failure.

Decay heat can be removed by either RHRS loop (A or B) operating in the suppression pool cooling mode. No credit was given for component restoration from test or maintenance for this sequence.

No credit was given to the Power Conversion System for this accident sequence. It is assumed that high drywell pressures will cause the Main Steam Isolation Valves to be interlocked closed during much of the accident.

The frequency of this sequence is estimated to be:

$$SI = 4.6 \times 10^{-6}$$

The dominant contributors, or cut sets, of this sequence are listed and described below. Maintenance contributions which would violate technical specifications have been removed from the following cut set frequencies.

Cut Set	Cut Set Frequency	Term Description
S*VGA2*VGB2	6.2×10^{-7}	S - A small loss of coolant accident (less than one square foot); F(S) = 1.4×10^{-3}
		VGB2 - Valve failure in the RHR heat exchanger bypass line, suppression pool return line, pump room cooling line, or seal cooling line (Train B); P(VGB2) = 2.4×10^{-2}
		VGA2 - Valve failure in the RHR heat exchanger bypass line, suppression pool return line, pump room cooling line, or seal cooling line (Train A); P(VGA2) = 2.4×10^{-2}
S*SSA*VGB2	4.2×10^{-7}	S, VGB2 (discussed above)

Cut Set	Cut Set Frequency	Term Description
		SSA - Hardware failure in Standby Service Water System loop A; P(SSA) = 2.1×10^{-2}
S*SSB*VGA2	4.2×10^{-7}	S, VGA2 (discussed above)
		SSB - Hardware failure in Standby Service Water System loop B; P(SSB) = 2.1×10^{-2}

The most probable cut sets for this sequence are characterized by hardware failures in the Residual Heat Removal System or Standby Service Water System which cause a loss of suppression pool cooling.

The dominant containment failure mode probabilities and release category placements for sequence SI were assessed to be:

$P(\alpha) = .01$; Category 1

$P(\delta) = 1.0$; Category 2

Multiplying the sequence frequency with the containment failure mode probabilities gives the values presented in Figure 6-1.

Sequence $T_1QW - \delta$:

This sequence is initiated by a loss of offsite power (T_1) followed by the unavailability of the Power Conversion System (Q) and the Residual Heat Removal System (W) to remove decay heat from the containment within 30 hours. Containment failure is predicted to be from an overpressure due to gas generation (δ).

Intermittent safety/relief valve opening, RCICS turbine exhaust, and ADS operation will necessitate residual heat removal during

the late part of the accident. Residual heat removal can be accomplished by successful operation of the Power Conversion System or by either RHRS loop (A or B) operating in the suppression pool cooling mode or the steam condensing mode. The availability of the Power Conversion system depends on the restoration of offsite power within 30 hours.

Core melt for this sequence begins sometime after the containment failure at 30 hours. Since this sequence involves long-term failures, a recovery factor was incorporated into the cut sets to reflect restoration from test or maintenance of critical components or other possible corrective actions which could be undertaken to mitigate the accident.

The frequency of this sequence is estimated to be:

$$T_1QW = 6.2 \times 10^{-6}$$

The dominant contributors, or cut sets, of this sequence are listed and described below.

Cut Set	Cut Set Frequency	Term Description
T_1*LOPNRE* LOPNRL*DIESEL1* DIESEL2*RECOVERY	1.1×10^{-6}	T_1 - Loss of offsite power; $F(T_1) = .2$/R-yr.
		LOPNRE - Nonrecovery of offsite power within about one half hour; P(LOPNRE) = .2
		LOPNRL - Nonrecovery of offsite power within 30 hours given LOPNRE; P(LOPNRL) = .1

Cut Set	Cut Set Frequency	Term Description
		DIESEL2 - Failure of diesel generator #2 to provide emergency power; P(DIESEL2) = 3.6×10^{-2}
		DIESEL1 - Failure of diesel generator #1 to provide emergency power; P(DIESEL1) = 3.6×10^{-2}
		RECOVERY - Failure to restore maintenance or test faults or take other corrective actions within 30 hours; P(RECOVERY) = .21
T_1*LOPNRE* LOPNRL*SSA* DIESEL2*RECOVERY	6.4×10^{-7}	T_1, LOPNRE, LOPNRL, DIESEL2, RECOVERY (discussed above)
		SSA - Hardware failure in Standby Service Water loop A; P(SSA) = 2.1×10^{-2}
T_1*LOPNRE* LOPNRL*SSB* DIESEL1*RECOVERY	6.4×10^{-7}	T_1, LOPNRE, LOPNRL, DIESEL1, RECOVERY (discussed above)
		SSB - Hardware failure of Standby Service Water loop B; P(SSB) = 2.1×10^{-2}
T_1*LOPNRE* LOPNRL*VGB1* DIESEL1*RECOVERY	4.5×10^{-7}	T_1, LOPNRE, LOPNRL, DIESEL1, RECOVERY (discussed above)
		VGB1 - Failure of valves on the inlet or outlet piping of RHR heat exchanger B; P(VGB1) = 1.5×10^{-2}

Cut Set	Cut Set Frequency	Term Description
T_1*LOPNRE* LOPNRL*VGA1* DIESEL2*RECOVERY	4.5×10^{-7}	T_1, LOPNRE, LOPNRL, DIESEL2, RECOVERY (discussed above) VGA1 - Failure of valves on the inlet or outlet piping of RHR heat exchanger A; P(VGA1) = 1.5×10^{-2}

The most probable cut sets for this sequence are characterized by nonrecovery of offsite power, which causes unavailability of the Power Conversion System, and hardware and power faults of the Residual Heat Removal System and Standby Service Water System which cause a loss of all suppression pool cooling.

The dominant containment failure mode probability and release category placement for sequence T_1QW was assessed to be:

$$P(\delta) = 1.0 \; ; \qquad \text{Category 2}$$

Multiplying the sequence frequency with the containment failure mode probability gives the value listed in Figure 6-1.

Sequence $T_{23}QW - \delta$:

This sequence is initiated by a T_{23} transient followed by the unavailability of the Power Conversion System (Q) and Residual Heat Removal System (W) to remove decay heat from the containment within 30 hours. Containment failure is predicted to be from an overpressure due to gas generation (δ).

Intermittent safety/relief valve opening, RCICS turbine exhaust, and ADS operation will necessitate residual heat removal

during the late part of the accident. Residual heat removal can be accomplished by successful operation of the Power Conversion System or by either RHRS loop (A or B) operating in the suppression pool cooling mode or steam condensing mode.

Core melt for this sequence begins sometime after the containment failure at 30 hours. Since this sequence involves long-term failures, a recovery factor was incorporated into the cut sets to reflect restoration from test or maintenance of critical components or other possible corrective actions which could be undertaken to mitigate the accident.

The frequency of this sequence is estimated to be:

$$T_{23}QW = 1.2 \times 10^{-5}$$

The dominant contributors, or cut sets, of this sequence are listed and described below. Maintenance contributions which would violate technical specifications have been removed from the following cut set frequencies.

Cut Set	Cut Set Frequency	Term Description
T_{23}*Q*SSA*SSB* RECOVERY	3.2×10^{-6}	T_{23} - A transient other than a loss of offsite power which requires reactor shutdown; $F(T_{23}) = 7/R\text{-}yr$
		Q - Failure of the Power Conversion System to remove decay heat within 30 hours; $P(Q) = 7.0 \times 10^{-3}$
		SSA - Hardware failure in Standby Service Water System loop A; $P(SSA) = 2.1 \times 10^{-2}$

Cut Set	Cut Set Frequency	Term Description
		SSB - Hardware failure in Standby Service Water System loop B; P(SSB) = 2.1×10^{-2}
		RECOVERY - Failure to restore maintenance or test faults or take other corrective action within 30 hours P(RECOVERY) = .21
T_{23}*Q*SSA* VGB1*RECOVERY	1.9×10^{-6}	T_{23}, Q, SSA, RECOVERY (discussed above)
		VGB1 - Failure of valves on the inlet or outlet piping of RHR heat exchanger B; P(VGB1) = 1.5×10^{-2}
T_{23}*Q*SSB* VGA1*RECOVERY	1.9×10^{-6}	T_{23}, Q, SSB, RECOVERY (discussed above)
		VGA1 - Failure of valves on the inlet or outlet piping of RHR heat exchanger A; P(VGA1) = 1.5×10^{-2}
T_{23}*Q*VGA1* VGB1*RECOVERY	9.4×10^{-7}	T_{23}, Q, VGA1, VGB1, RECOVERY (discussed above)

The most probable cut sets of this sequence are characterized by hardware failures of the Standby Service Water System and Residual Heat Removal System which cause a loss of all suppression pool cooling.

The dominant containment failure mode probability and release category placement for sequence $T_{23}QW$ was assessed to be:

$$P(\delta) = 1.0 \quad ; \quad \text{Category 2}$$

Multiplying the sequence frequency with the containment failure mode probability gives the value presented in Figure 6-1.

Sequence $T_{23}C - \delta$:

This sequence is initiated by a T_{23} transient followed by a failure to achieve reactor subcriticality (C). Containment failure is predicted to occur from an overpressure due gas generation (δ).

Following the failure to scram, reactor power is expected to equilibrate at approximately 30 percent. The resulting heat rejection to the suppression pool is calculated to be greater than the residual heat removal capacity of the RHR system. This causes the containment to overpressurize and fail in about 71 minutes. Containment failure then leads to ECCS failure and core melt due to suppression pool boiling and subsequent pump cavitation.

The frequency of this sequence is estimated to be:

$$T_{23}C = 5.4 \times 10^{-6}$$

The dominant contributor, or cut set, of this sequence is listed and described below.

Cut Set	Cut Set Frequency	Term Description
$T_{23}*C$	5.4×10^{-6}	T_{23} - A transient other than a loss of offsite power which requires a reactor shutdown; $F(T_{23}) = 7/R\text{-}yr$
		C - Failure to achieve reactor subcriticality; $P(C) = 7.7 \times 10^{-7}$

The dominant containment failure mode probability and release category placement for sequence $T_{23}C$ was assessed to be:

$$P(\delta) = 1.0 \quad ; \quad \text{Category 2}$$

Multiplying the sequence frequency by the containment failure mode probability gives the value presented in Figure 6-1.

Sequence $T_1QUV - \gamma, \delta$:

This sequence is initiated by a loss of offsite power (T_1) followed by the unavailability of the Power Conversion System (Q) and failure of the high pressure systems (U) and low pressure injection systems (V) to provide emergency core cooling. Containment failure is predicted to occur from an overpressure due to rapid hydrogen burning (γ) or overpressure due to gas generation (δ).

Availability of the Power Conversion System is dependent on the recovery of offsite power within about one half hour.

Emergency core cooling can be achieved by the High Pressure Core Spray, the Reactor Core Isolation Cooling System, the Low Pressure Core Spray, or two of three Low Pressure Coolant Injection System trains. Successful low pressure injection requires manual Automatic Depressurization System actuation. It was assumed that system parameters do not reach the automatic ADS initiation setpoints. Core melt is expected to occur shortly after injection failure.

The frequency of this sequence is estimated to be:

$$T_1QUV = 1.5 \times 10^{-6}$$

The dominant contributors, or cut sets, of this sequence are listed and described below.

Cut Set	Cut Set Frequency	Term Description
T_1*LOPNRE*OP*R*DIESEL3	1.1×10^{-7}	T_1 - Loss of offsite power; $F(T_1) = .2$/R-yr. LOPNRE - Nonrecovery of offsite power within about one half hour; P(LOPNRE) = .2 OP - Failure of the operator to initiate the Automatic Depressurization System; P(OP) = 1.5×10^{-3} R - Hardware failure of the Reactor Core Isolation Cooling System; P(R) = 5.1×10^{-2} DIESEL3 - Failure of diesel generator #3 to provide emergency power; P(DIESEL3) = 3.6×10^{-2}
T_1*LOPNRE*R*DIESEL1*DIESEL2*DIESEL3	9.5×10^{-8}	T_1, LOPNRE, R, DIESEL3 (discussed above) DIESEL2 - Failure of diesel generator #2 to provide emergency power; P(DIESEL2) = 3.6×10^{-2} DIESEL1 - Failure of diesel generator #1 to provide emergency power; P(DIESEL1) = 3.6×10^{-2}
T_1*LOPNRE*OP*R*H	6.4×10^{-8}	T_1, LOPNRE, OP, R (discussed above) H - Hardware failure in the High Pressure Core Spray; P(H) = 2.1×10^{-2}

The most probable cut sets for this sequence are characterized by hardware failures of the RCICS, hardware and power faults of the HPCS, and the operator failing to depressure the reactor so the low pressure injection systems can be available.

The dominant containment failure mode probabilities and release category placements for sequence T_1QUV were assessed to be:

$$P(\gamma) = .5 \quad ; \quad \text{Category 3}$$

$$P(\delta) = .5 \quad ; \quad \text{Category 4}$$

Multiplying the sequence frequency by the containment failure mode probabilities gives the values presented in Figure 6-1.

6.2 Comparison With the Dominant Accident Sequences in the Reactor Safety Study

Two Peach Bottom sequences dominated the four BWR core melt release categories as shown in Figure 6-2. A short description of each is presented below.

TW - α, γ', γ: A transient (T) followed by a failure to remove decay heat from the containment within 27 hours using either the Residual Heat Removal or the Power Conversion System (W). Containment failure is predicted to occur from a steam explosion in the vessel (α), an overpressure with a direct release to the atmosphere (γ'), or overpressure with a release through the reactor building (γ).

TC - α, γ: A transient (T) followed by a failure to render the reactor subcritical (C). Containment failure is predicted to occur from a steam explosion in the vessel (α) or an overpressure with a release through the reactor building (γ).

These two Peach Bottom sequences dominate the four RSS core melt release categories for BWRs. All of the other Peach Bottom sequences were several orders of magnitude smaller.

The anticipated transient without scram sequence (TC) for Grand Gulf was slightly lower in frequency than that of Peach Bottom's. Both are dominant sequences. However, the TC sequence for Peach Bottom was placed in categories 1 and 3 and includes a steam explosion containment failure mode. The dominant sequence at Grand Gulf falls in category 2 and results in an overpressure containment failure mode due to gas generation. The reason for the TC sequence frequency difference between Grand Gulf and Peach Bottom was due to the fact that for T_1 initiators, logic circuit faults were removed from the Grand Gulf Reactor Protection System (RPS) unavailability. The RPS logic circuits are not required on loss of power since the system will trip due to the initiator.

The equivalent of the Peach Bottom TW sequence is the Grand Gulf sequence TQW. Both sequences represent a failure of the Power Conversion System and Residual Heat Removal System to remove decay heat from the containment after a transient and successful emergency core cooling. While the sequence frequencies of this accident are almost identical for Grand Gulf and Peach Bottom, the systems and components involved and parts of the analysis were quite different. The RHRS at Peach Bottom consists of two cooling trains, each with two pumps and two heat exchangers. The RHRS at Grand Gulf also consists of two trains but each only has a single pump and heat exchanger. Another difference between the two RHR systems is the steam condensing mode available at Grand Gulf. Main

steam can be routed through the RHR heat exchangers and condensed in this mode of operation. Refer to Figure B10-2. A steam condensing mode of residual heat removal is not available at Peach Bottom. In addition to this, a recovery factor was incorporated into every cut set of Grand Gulf's TQW sequence to reflect possible restoration from test or maintenance of critical components or other corrective actions which might be taken to mitigate the accident. In the analysis of Peach Bottom's TW sequence, the only credit given for restoration was to the High Pressure Service Water System which supplies water to the secondary sides of the RHR heat exchangers. Thus, the added restoration factor tended to compensate for the less reliable RHR system at Grand Gulf.

Several important sequences at Grand Gulf were not found to be dominant at Peach Bottom. One such sequence is TPQI which is comparable to the Peach Bottom TPW sequence. Each represents a transient (T) followed by a safety/relief valve sticking open (P) and a failure of all long-term residual heat removal (QI or W). In the analysis of these sequences, successful residual heat removal can be accomplished by either the Residual Heat Removal System (RHRS) drawing water from the suppression pool and cooling it in the RHR heat exchangers or the Power Conversion System condensing main steam in the condenser. Either of these systems can remove decay heat from the containment and thus prevent an overpressure containment failure mode and subsequent core melt.

As in the TQW sequence, a recovery factor was incorporated into all of the sequence TPQI cut sets. This recovery factor reflects possible restoration from test or maintenance of critical

components or corrective actions which might be taken to mitigate the accident.

Despite the inclusion of a recovery factor, the frequency of the TPQI sequence at Grand Gulf was calculated to be about four times higher than the comparable TPW sequence frequency for Peach Bottom. This is probably due to the fact that Grand Gulf's RHRS is slightly less redundant than Peach Bottom's system. No credit for the steam condensing mode of RHRS operation was given for TPQI or LOCA sequences in the Grand Gulf analysis due to the complexity of the system operation.

Another accident sequence which is dominant at Grand Gulf and not dominant at Peach Bottom is TPQE. The TPQE sequence is comparable to the Peach Bottom TPQUV sequence. Each represents a transient (T) followed by a safety/relief valve sticking open (P) and a loss of all emergency coolant injection (QE or QUV).

In the analysis of sequence TPQUV, successful coolant injection can be established by the Power Conversion System (PCS) drawing water from the Condensate Storage Tank. Event Q, for this sequence, represents failure of the PCS and its value ranges from .01 to .2 depending on the initiator.

For the Grand Gulf TPQE sequence, no credit has been given for the Power Conversion System during the early injection phase of the accident (Q = 1.0). It has been assumed that the Power Conversion System (PCS) will be interrupted shortly after a transient involving a stuck-open relief valve and therefore must be recovered to provide coolant injection. The PCS will be interrupted when the Main Steam Isolation Valves (MSIVs) close (MSIV closure on low reactor

water level or steam pressure is expected). PCS recovery will depend on: (1) the reopening of the MSIVs, (2) reestablishing the condenser vacuum, if needed, (3) restoration of offsite power (T_1 transients), and (4) switchover to the auxiliary steam supply to the Steam Jet Air Ejectors (which maintain condenser vacuum) when primary steam pressure drops below approximately 150 psia. Since core melt for this sequence begins at 71 minutes and some of the recovery actions take a long time to accomplish (.3 to 2 hours for getting the MISVs open according to utility information), no credit was given for the PCS for coolant injection for TPQE sequences.

Because of this different assumption on PCS availability, the TPQE sequence for Grand Gulf has a frequency more than an order of magnitude higher than that calculated for the comparable Peach Bottom sequence.

The SI sequence at Grand Gulf involves a small LOCA and loss of all long-term residual heat removal. The comparable sequences at Peach Bottom are SI and SJ and were not dominant. The Residual Heat Removal System at Grand Gulf is somewhat less redundant than Peach Bottom's. This caused the SI frequency for Grand Gulf to be approximately an order of magnitude higher than what was calculated for the similar Peach Bottom sequences. No recovery or steam condensing credit was given for this sequence.

The T_1QUV accident sequence at Grand Gulf involves a loss of offsite power followed by failures of the PCS and all high and low pressure injection systems. The comparable sequence at Peach Bottom, also labeled T_1QUV, was not dominant. The difference between the two sequences is that the Grand Gulf High Pressure Core

Spray System has an electric driven pump and the Peach Bottom system has a turbine driven pump. This dependency on offsite or emergency diesel AC power causes the Grand Gulf T_1QUV sequence frequency to to be a factor of five higher than the frequency of Peach Bottom's.

6.3 Conclusions, Limitations, and Current Issues

6.3.1 Conclusions

In general, the methods used to determine the core melt accident sequences for Peach Bottom in the RSS were found to be applicable in the analysis of the Grand Gulf reactor.

The dominant accident sequences identified in the Reactor Safety Study were also dominant at Grand Gulf. These were transient sequences involving failure of long-term heat removal and anticipated transients without scram. There were, however, several types of sequences which were dominant at Grand Gulf, but not at Peach Bottom. These include transients with a stuck-open relief valve and loss of long-term residual heat removal, transients with a stuck-open relief valve and loss of emergency coolant injection, small LOCAs with loss of long-term residual heat removal, and loss of offsite power transients with no emergency coolant injection. The reasons these sequences were dominant at Grand Gulf and not dominant at Peach Bottom were due to either plant design differences or differences in the assumptions made.

One assumption made that caused several accident sequence frequencies to be quite different from those at Peach Bottom was that the Power Conversion System would not be available after TPQE

sequences. It should be noted that this assumption could be applicable to Peach Bottom, and if it had not been made for Grand Gulf, the particular sequence frequencies would have been much closer.

An example of a design difference between Grand Gulf and Peach Bottom that caused an accident sequence frequency to be different is the type of high pressure core cooling pump used at each plant. Peach Bottom's High Pressure Coolant Injection System has a turbine driven pump and Grand Gulf's High Pressure Core Spray System utilizes an electric driven pump.

Containment failure from an overpressure due to rapid hydrogen burning was important for Category 3 sequences at Grand Gulf. The Category 3 sequences involving hydrogen burning contribute about 3 percent to the overall core melt frequency. Conversely, release Category 2 sequences involve containment failure due to overpressure caused by gas generation and contribute over 90 percent to the overall core melt frequency. The results of this study therefore suggests that core melt accident sequences involving hydrogen burning are not major contributors to risk at the Grand Gulf plant. This stems from the fact that for the most dominant accident sequences, the containment fails before core melting begins. Significant hydrogen is not expected to be generated until the core melt process begins. Hydrogen burning at Peach Bottom was not considered since its Mark I containment is inerted.

The overall core melt frequency assessed for Grand Gulf was found to be very close to that calculated for Peach Bottom (3.7×10^{-5} vs. 2.9×10^{-5} per reactor year, respectively).

6.3.2 Limitations

The following limitations were identified in the RSSMAP program.

The Grand Gulf Final Safety Analysis Report and limited discussions with plant personnel were the primary sources of information utilized in this study. Since the Grand Gulf plant was under construction while this study was being done, no technical specifications or procedures were available during the analysis. A more rigorous analysis would require additional information. This upgraded information base should include as built piping and instrumentation diagrams, plant procedures, and direct contacts with the plant personnel and designers for purposes of answering technical questions.

The Reactor Core Isolation Cooling System was assumed to be capable of providing successful coolant injection for the whole spectrum of small LOCAs (less than 13.5 inches equivalent diameter). The LOCA success criteria was determined using the best available information from the FSAR and the utility. It is acknowledged that this assumption on the RCICS capability may be nonconservative. Credit for the RCICS was given to LOCAs of only up to 2 inches in the Reactor Safety Study. Calculations show, however, that not giving credit for the RCICS for LOCAs 2 inches to 13.5 inches in diameter would change the Release Category 3 total by 10%, the Category 4 total by 2%, and the overall core melt frequency by less than 1%. It is recommended that future studies incorporate more detailed success criteria into their analyses which look at more break sizes, including liquid and steam breaks, and a larger variety of transient initiators.

The majority of the data base utilized in this study was compiled as part of the RSS. Parts of this data base were developed from generic industry data. Several of the RSS numbers used directly affected the dominant accident sequence frequencies and can swing those frequencies orders of magnitude depending on the assumptions made. Examples are the numbers used for the availability and recovery of the Power Conversion System given different transients. A more rigorous study should review and update the RSS data and use plant specific data whenever possible.

This study attempted to identify human errors which could degrade or lead to failure of the safety systems responding to a LOCA or transient. These human errors were of two basic types, (1) those errors occurring during routine operation, such as inadvertently leaving valves in the wrong position, and (2) errors which occur during the course of an accident such as an operator failing to manually initiate the Automatic Depressurization System when needed. In order to assess operator errors during the course of an accident, the analyst must be aware of the plant parameter indications which the operator is relying upon to make decisions in the control room (e.g., at TMI the operator terminated the high pressure injection system because of a high pressurizer level indication). To gain these types of insights, it is recommended that future, more complete analyses perform detailed calculations of plant system dynamics associated with each accident sequence and thoroughly review operating and emergency procedures.

The Mark III containment used at Grand Gulf is much different than the one used at Peach Bottom. It is of a new design and questions exist regarding its response to various conditions. Assumptions and estimates have been made in this study regarding suppression pool heatup, hydrogen burning, and primary containment leakage. For example, a plant specific primary containment leakage probability was not calculated. It was assumed that the Mark III containment leakage paths would be no worse than those found at the Oconee PWR. Both plants have atmospheric containments with no constant monitoring system to detect containment leakage. Therefore, a .007 containment leakage probability was assessed for Grand Gulf based on Oconee's number (reference 9). None of the sequences involving containment isolation failure were found to be among the dominant ones in the analysis; however, due to the predominance of overpressure containment failure mode sequences. A more rigorous analysis should include a detailed analysis of the Mark III containment.

6.3.3 Current Issues

Several problems and issues concerning reactor safety have arisen since Three Mile Island which have not been explicitly incorporated into this analysis. These current issues are discussed briefly below and the potential impact on this study is given.

A partial failure to scram occurred at Browns Ferry Unit 3 in 1980. The apparent cause of this event was found to be water accumulation in the scram discharge volume (SDV) prior to the attempted scram. This particular failure was not included

in the analysis of the Grand Gulf Reactor Protection System. The SDV design at Grand Gulf is, however, much different than the one at Browns Ferry and is expected to be less susceptible to a Browns Ferry type scram failure.

A potential accident which was identified after the Browns Ferry incident is a LOCA caused by a pipe break in a BWR Control Rod Hydraulic Supply System outboard of one of the scram valves. The Probabilistic Analysis Staff (now part of the Division of Risk Analysis in the Office of Research) of the NRC has determined that while current BWR scram systems do violate isolation valve requirements, this type of BWR scram system LOCA is not a major contributor to risk (Reference 10). For this reason, the Grand Gulf analysis was not updated to include this type of accident.

Another potential area of concern which has received attention within the NRC recently is the probability of BWR recirculation pump seal failures. Documentation exists (Reference 11) which suggests that the probability of seal leaks of 50 gpm or greater could be as high as .01 as an initiating event. This is an order of magnitude higher than the small LOCA frequency in the RSS and RSSMAP. Such seal leaks were not included in the Grand Gulf LOCA definitions and, if included, would have the effect of increasing the frequencies of all small (S) LOCA sequences.

Several accident scenarios involving failure of DC power which have been identified recently may be applicable to Grand Gulf. One scenario involves total DC power failure due to battery depletion during station blackout conditions. Another

scenario involves immediate DC power loss following a loss of offsite power due to a common mode failure of the station batteries (Reference 12). Both of these accidents would affect the operation of the RCICS and diesel generators and affect possible recovery actions. The probability of occurrence of these scenarios is dependent on the AC and DC power system configurations, accident loads on these systems, and operator procedures. The overall effect of these DC power accidents, given they are applicable to Grand Gulf, would be to increase the frequencies of the T_1 accident sequences.

Finally, there have been a number of proposed design changes which, if eventually incorporated into the Grand Gulf design, could significantly change the identified dominant accident sequences and frequencies. A few of these are: hydrogen control devices, containment venting, automatic restart of the RCICS and LPCIS, and ATWS 3A implementations which would increase reactor shutdown reliability. These potential design changes have not been incorporated into the Grand Gulf analysis because information on their potential use was not available at the time of completion of this analysis.

Table 6-1. Symbols Used in Figure 6-1

Initiating Events

T_1 - A loss of offsite power transient.

T_{23} - Any other transient which requires an emergency reactor shutdown.

S - A small LOCA (the break area is less than one square foot).

System, Component, or Functional Failures

C - Failure to render the reactor subcritical.

E - Failure of the Emergency Core Cooling System.

I - Failure of residual heat removal systems after a LOCA (including transient induced LOCAs).

P - Failure of a safety/relief valve to reseat.

Q - Failure of the Power Conversion System.

U - Failure of the High Pressure Core Spray and Reactor Core Isolation Cooling System.

V - Failure of the low pressure ECCS systems to provide core flow.

W - Failure of the residual heat removal systems after a transient.

Table 6-1 (continued)

Containment Failure Modes[1]

α - Containment failure due to a steam explosion.

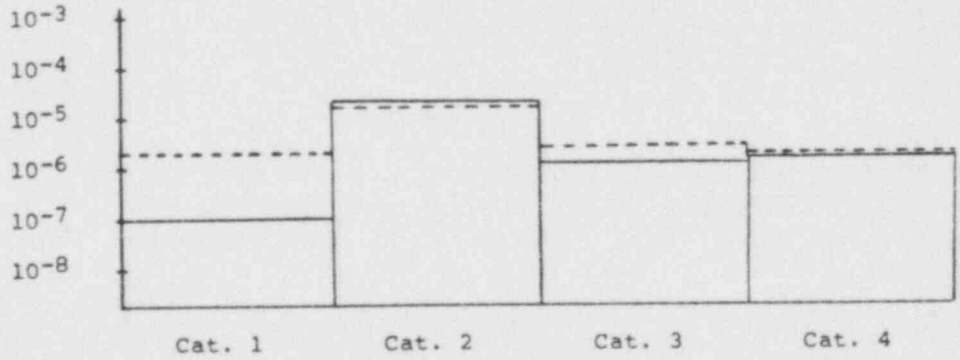
γ - Containment failure due to an overpressure caused by rapid hydrogen burning.

δ - Containment failure due to an overpressure caused by gas generation.

(1) The symbols used for the Grand Gulf containment failure modes are somewhat different than those used in the RSS.

DOMINANT ACCIDENT SEQUENCES	BWR Core Melt Release Categories			
	1	2	3	4
T_1PQI	$\alpha 1.6 \times 10^{-8}$	$\delta 1.6 \times 10^{-6}$		
$T_{23}PQI$	$\alpha 3.7 \times 10^{-8}$	$\delta 3.7 \times 10^{-6}$		
T_1PQE			$\gamma 1.2 \times 10^{-7}$	$\delta 1.2 \times 10^{-7}$
$T_{23}PQE$			$\gamma 2.7 \times 10^{-7}$	$\delta 2.7 \times 10^{-7}$
SI	$\alpha 4.6 \times 10^{-8}$	$\delta 4.6 \times 10^{-6}$		
T_1QW		$\delta 6.2 \times 10^{-6}$		
$T_{23}QW$		$\delta 1.2 \times 10^{-5}$		
$T_{23}C$		$\delta 5.4 \times 10^{-6}$		
T_1QUV			$\gamma 7.5 \times 10^{-7}$	$\delta 7.5 \times 10^{-7}$
CATEGORY[1] TOTAL	1.1×10^{-7}	3.4×10^{-5}	1.2×10^{-6}	1.4×10^{-6}

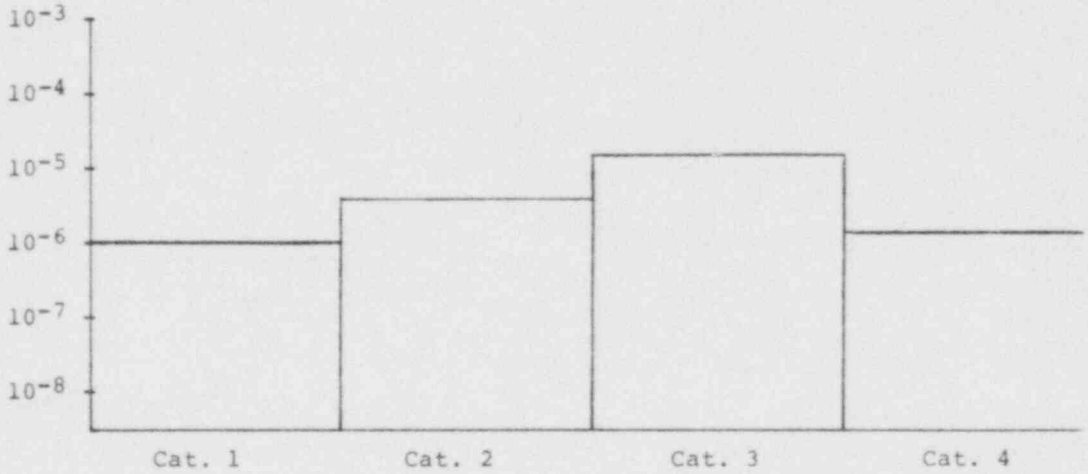
[1] This is an unsmoothed total which includes the contribution from all the nondominant sequences not shown.



(The solid lines show the category totals shown above. The dotted lines show the results after application of the RSS 'smoothing' technique.)

Figure 6-1. Grand Gulf Dominant Core Melt Accident Sequences

	Core	Melt	Release	Categories
Dominant Accident Sequences	1	2	3	4
TW	α 2.0×10^{-7}	γ' 3.0×10^{-6}	γ 1.0×10^{-5}	
TC	α 1.0×10^{-7}		γ 1.0×10^{-5}	
Category Total	1.0×10^{-6}	6.0×10^{-6}	2.0×10^{-5}	2.0×10^{-6}



NOTE: The probabilities for each release category are the summations of values of the dominant accident sequences by Monte Carlo simulation plus a 10% contribution from the adjacent release category probability. Category 4 is totally dominated by sequences in other categories due to this smoothing.

Figure 6-2. Peach Bottom Dominant Core Melt Accident Sequences

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APPENDIX A1

LOCA EVENT TREE - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf LOCA event tree is displayed in Figure A1-1. For comparison, the Peach Bottom LOCA event trees are shown in Figures A2-1, 3, and 4. A discussion of the functions that the Grand Gulf systems perform following a LOCA is presented in Section 2.1. The Grand Gulf LOCA event tree is explained in detail in Section 2.2. In Section 3, a comparison of the Grand Gulf and Peach Bottom LOCA event trees is made.

2.0 GRAND GULF LOCA EVENT TREE

2.1 Event Tree Functions

There are four basic functions which engineered safety features perform following a LOCA. These are to:

1) render the reactor subcritical,
2) provide emergency core cooling,
3) prevent containment overpressurization and
4) prevent radioactive material from escaping the containment environment.

Immediately following a LOCA, it is important to stop the fission process in the core. This function is performed by the Reactor Protection System (RPS) and involves the simultaneous insertion of all reactor control rods into the core. In the event of a recirculation line break, the most demanding break in terms of ECCS performance requirements, the reactor will initially shut down due to coolant voiding in the core. However, to prevent a power surge when cold unborated ECCS water enters the reactor, it is necessary for the control rods to be inserted.

Four Grand Gulf systems can be used to provide emergency core cooling after an accident. These systems are the High Pressure Core Spray (HPCS), Low Pressure Core Spray (LPCS), Reactor Core Isolation Cooling System (RCICS), and the Low Pressure Coolant Injection System (LPCIS). These systems deliver water to the core to prevent excessive fuel cladding temperatures and possible core damage. For small breaks, the Automatic Depressurization System functions to lower system pressure to a level at which the LPCS and LPCIS can operate. For large breaks it is assumed the vessel will depressurize through the break.

The Reactor Core Isolation Cooling System (RCICS) is not normally considered part of the ECCS, but was considered in the RSS for some loss-of-coolant accidents. Therefore, credit was given to the RCICS at Grand Gulf for small (S) LOCAs even though it was not included in the plant response analysis done by the vendor.

The Reactor Core Isolation Cooling System was assumed to be capable of providing successful coolant injection for the whole spectrum of small LOCAs (less than 13.5 inches equivalent diameter). The LOCA success criteria was determined using the best available information from the FSAR and the utility. It is acknowledged that this assumption on the RCICS capability may be nonconservative. Credit for the RCICS was given to LOCAs of only up to 2 inches in the Reactor Safety Study. Calculations show, however, that not giving credit for the RCICS for LOCAs 2 inches to 13.5 inches in diameter would change the Release Category 3 accident sequence

frequency total by 10%, the Category 4 total by 2%, and the overall core melt frequency by less than 1%.

No credit was given to the Power Conversion System (PCS) at Grand Gulf for emergency coolant injection or residual heat removal after loss-of-coolant accidents. The PCS will initially be lost after a LOCA due to Main Steam Isolation Valve closure on low water level or low steam pressure. Recovery of the PCS was deemed to be improbable due to the many manual actions which must be performed and due to the fact that the MSIVs will be interlocked shut on high drywell pressure which is expected throughout most LOCA sequences.

Throughout a LOCA, steam will be ejected into the drywell. It is the function of the Vapor Suppression System (VSS) to limit the resulting pressure transient in the drywell by condensing steam in the suppression pool. Steam from a LOCA could, if not quenched, pressurize the containment to levels exceeding its structural integrity. As a LOCA progresses, more and more energy will be deposited into the suppression pool. This will eventually cause the suppression pool to heat up which in turn could cause primary containment overpressurization. The Residual Heat Removal System (RHRS), in conjunction with the Standby Service Water System (SSWS), is used to remove heat from the suppression pool on a longterm basis.

The consequences of a containment rupture can be minimized if the amount of radioactive material in the containment atmosphere is kept at a minimum. The VSS is designed to meet that goal. Radioactive steam will condense as it passes through the horizontal

vents in the suppression pool. The containment spray system can also remove radioactive particles in the containment and therefore provides an additional means of removing radioactivity from the containment atmosphere.

A summary of the systems required to perform ESF functions during a LOCA is given in Table A1-1.

2.2 Event Tree Definitions and Tree Development

The Grand Gulf LOCA event tree is shown in Figure A1-1. The systems which perform the four functions described in Section 2.1 make up the event tree headings. Dependencies between these systems dictate the event tree structure. A single LOCA event tree is an adequate representation for the entire spectrum of break sizes, since the tree structure and tree headings are identical for all breaks. However, some of the tree heading definitions do differ. A discussion of the heading definitions and tree structure follows.

2.2.1 Events A and S - Breaks in the Reactor Coolant System (RCS)

The LOCA initiating events are due to random ruptures of the RCS, which fall in the following break size ranges:

A LOCA equivalent diameter > 13.5 inches

S LOCA equivalent diameter < 13.5 inches

The large LOCA initiating event is a random rupture of a reactor coolant system pressure boundary pipe creating an opening greater than 1.0 square foot. This size break will depressurize the system without relief valves, HPCS, or ADS assistance.

The Small LOCA initiating event is a random rupture less than 1.0 square foot. This LOCA requires system depressurization before low pressure emergency cooling systems can operate.

These LOCA size definitions reflect the ECCS ability to adequately maintain water inventory in the reactor vessel as discussed in Section 2.2.4. The LOCA break sizes were chosen based on discussions with utility and General Electric personnel.

In addition to random ruptures, LOCAs can be transient induced. This latter type is caused by the failure of an RCS relief valve to reclose after being demanded in response to a transient. This LOCA would fall in the 'S' LOCA break size range and is described in Appendix A2.

2.2.2 Event C - Reactor Protection System (RPS)

Reactor shutdown after a LOCA is accomplished by the Reactor Protection System inserting all the control rods into the core. The RPS is automatically initiated if certain monitored variables exceed their setpoints, e.g., high drywell pressure or low reactor vessel water level. No credit is given for the Standby Liquid Control System for LOCAs since it is a manually initiated system. Therefore, the value used in the LOCA sequence analysis for Event C is the unavailability calculated in Appendix B1 for the RPS. For LOCAs, this value was found to be 7.7×10^{-6}.

Failure of the RPS is defined as the failures of more than two adjacent control rods to insert to make the reactor subcritical prior to reflooding the core with ECCS water. As in the RSS, it has

been assumed that at 100°C, more than two adjacent rods not inserted will give a K_{eff} greater than 1.0.

RPS failure was placed immediately following the initiating event because its failure alone will result in the reactor remaining at significant power levels which eventually lead to a core melt. The RPS was treated as an independent system and its unavailability is estimated in Appendix B1.

2.2.3 Event D - Vapor Suppression System (VSS)

The Vapor Suppression System is designed to condense steam released from a LOCA break. As gases and steam are released, they are swept through horizontal vents into the suppression pool and scrubbed by the water in the wetwell, thus capturing much of the radioactivity released and reducing the overall containment pressure. The containment sprays were included in the VSS analysis since, given small drywell bypass leakage, they can prevent the containment from overpressurizing.

Failure of the VSS is defined as the failure of the suppression pool and containment sprays to condense an adequate quantity of steam to lower the pressure to a value which does not cause the primary containment to fail structurally.

This event was placed after the RPS event because its failure could cause the containment to rupture and increases the probability of failure of the emergency core cooling systems. The equations and unavailabilities used to model this system are described in Appendix B4.

2.2.4 Event E - Emergency Coolant Injection (ECI)

A number of systems operate in different combinations to prevent core damage for the various break sizes. These systems are the High Pressure Core Spray (HPCS), the Reactor Core Isolation Cooling System (RCICS), Low Pressure Core Spray (LPCS), Low Pressure Coolant Injection System (LPCIS), and the Automatic Depressurization System (ADS).

As in the RSS, it is assumed that actuation of the ADS is required for successful low pressure emergency core cooling after small and transient induced LOCAs despite depressurization effects of the pipe break or stuck-open relief valve.

The Grand Gulf FSAR states that successful core cooling for small line breaks can be accomplished by the HPCS or depressurization with ADS bank A or ADS bank B and low-pressure core cooling with the LPCS or any two LPCIS pumps. Similarly, for large breaks, the LPCS, HPCS, or three LPCIS pumps can achieve successful core cooling.

The Reactor Core Isolation Cooling System was considered in the analysis of small LOCAs at Grand Gulf even though it was not included in the plant response analysis done by the vendor. As in the RSS, the RCICS is considered redundant to the HPCS and available for emergency core cooling after small LOCAs.

Emergency coolant injection requirements are different for the two LOCA break sizes. In the analysis, transient induced LOCAs are treated as small LOCAs. These success requirements are:

For A LOCAs: HPCS
or
LPCS
or
3 of 3 LPCI loops

For S LOCAs: HPCS
or
RCICS
or
ADS and LPCS
or
ADS and 2 of 3 LPCI loops

Using the above success definitions, failure criteria can be established for each LOCA size. These are:

For A LOCAs: HPCS and LPCS and 1 of 3 LPCI loops

and

For S LOCAs: HPCS and RCICS and ADS
or
HPCS and RCICS and LPCS and 2 of 3 LPCI loops

The above system failures (HPCS, LPCS, etc.) represent the inability of the system to deliver water to the reactor vessel and can result from hardware, maintenance, or human errors. Refer to Appendix B. ECI must continue after a LOCA until the core has been reflooded, at which time any one of the above systems is sufficient to maintain water inventory in the core.

2.2.5 Event I - Residual Heat Removal (RHR)

Once the core has been reflooded, the coolant injection requirements diminish and the need for residual heat removal increases. The suppression pool water heats up after a LOCA and will overpressurize the containment if not cooled. Successful residual heat removal depends on three systems: the Suppression Pool Makeup System (SPMS), Residual Heat Removal System (RHRS), and the Standby Service Water System (SSWS).

In order for the RHR heat exchangers to safely remove decay heat from the suppression pool on a longterm basis, the bulk of water in the upper containment pool must be delivered to the suppression pool by the SPMS dump lines. This added water also ensures adequate long term vent coverage for all break sizes.

In addition to this, successful RHR depends on either RHRS loop A or B operating in the suppression pool cooling mode. This means that one flowpath from the suppression pool through a heat exchanger and back to the suppression pool must be established. The steam condensing mode of the RHRS was not considered for LOCAs. This is due to the fact that successful operation of the steam condensing mode requires RCICS operation and the RCICS will not be available long term due to low steam pressures. One final requirement is that the SSWS supplies cooling water to the shell side of the operating heat exchanger. A Boolean representation of RHR failure is therefore:

RHR failure = SPMS + [RHR Loop A + SSWS Loop A]
*[RHR Loop B + SSWS Loop B] .

The Boolean equations used to model the SPMS, RHRS, and SSWS are found in Appendices B11, B10, and B12, respectively.

Since the success or failure of the RHRS cannot delay or prevent containment failure or core melt given failure of all emergency core cooling, no choice is given for Event I given occurrence of Event E. According to analyses performed by Battelle Columbus Laboratories, given successful core cooling, the Grand Gulf containment will fail in approximately 28 hours without

suppression pool cooling. The containment failure is predicted to occur from an overpressure caused by gas generation.

For transient induced LOCA sequences involving long-term heat removal failure (Event I), a nonrecovery term was added to every cut set. Containment failure and subsequent core melt is expected to occur in 28 hours following residual heat removal failure. It is assumed that an attempt will be made to restore or repair any components necessary for residual heat removal during this period. The probability that repairs are not com pleted within 28 hours, given a mean repair time of 19 hours, is conservatively estimated as in the RSS by an exponential repair distribution.

$$P(\text{RHRS not repaired}) = \exp(-28/19) = .23$$

This nonrecovery factor was incorporated into all transient induced LOCA sequences involving failure of residual heat removal.

3.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM LOCA EVENT TREES

The RSS constructed three LOCA trees representing plant response to three different break size ranges for the Peach Bottom reactor (see Figures A1-2, 3, 4). Due to substantial differences in the plant systems' response to varying LOCA sizes, a single LOCA tree was not an adequate representation of the plant response and thus, three trees were created. For the Grand Gulf reactor, as discussed previously, one tree was an adequate representation. Some of the event definitions change, however, depending on which initiating LOCA size is being considered.

The Peach Bottom LOCA trees all include an Event B, electric power. The Grand Gulf tree does not include this event. Instead, electric power was incorporated directly into the Boolean equations developed for each system. In this way, partial electric power failures have been explicitly included in the analysis. Incorporating the electric power event into the system equations also simplifies the LOCA event tree.

The Peach Bottom large LOCA event tree had an Event F, ECF or Emergency Cooling Functionability. In large LOCAs, substantial blowdown forces can occur which have the potential to damage portions of the core or RCS in ways that can affect the ability of the ECCS to adequately cool the core. For this reason, the ECF event was added after Event E, ECI. ECF was not included in the small LOCA trees since the forces involved are much smaller and the chance of failure considered negligibly small. However, the RSS finally concluded that the large LOCA event with or without ECF probability values included would contribute less than 15 percent to the total core melt frequency over the entire release spectrum. For this reason, ECF was not included in the Grand Gulf analysis.

A containment leakage event (CL) was included on the Peach Bottom LOCA trees to show that failure or success of the containment isolation systems will affect the timing of possible ECCS pump failures. If containment leakage is less than a certain amount, the ECCS pumps are expected to operate until the primary containment fails due to overpressure. If containment leakage is greater than a certain amount, then the ECCS pumps are assumed

to fail earlier due to cavitation caused by a loss of net positive suction head. A containment leakage event was not included on Grand Gulf's LOCA tree because the ECCS pumps at Grand Gulf are rated to 212°F and would therefore not be expected to fail from primary containment leakage. Leakage would cause the primary containment atmosphere to remain at around atmospheric pressure which would keep the suppression pool water at 212°F.

Drywell leakage at Grand Gulf is included in the vapor suppression system analysis. Excess drywell leakage would cause steam to bypass the suppression pool and quickly overpressurize the containment. Refer to Appendix B4. This vapor suppression system failure mode was not significant at Peach Bottom. The containment sprays at Grand Gulf were included in the vapor suppression analysis. Given small drywell bypass leakage, the sprays can prevent the containment from overpressurizing. Peach Bottom does have drywell and wetwell sprays; however, no credit was given to them in the RSS.

The last three events on the Peach Bottom LOCA trees are the Core Spray Recirculation System (CSRS), Low Pressure Cooling Recirculation System (LPCRS), and the High Pressure Service Water System (HPSWS). The events describe failure of core cooling systems in the recirculation mode and failure of the service water systems to remove decay and sensible heat from the wetwell and pump compartments. These three events have been combined into Event I, Residual Heat Removal, on the Grand Gulf tree since no "new" accident sequences, in terms of consequences, are created by splitting out RHR and cooling water failures. The

systems represented by Event I are the Suppression Pool Makeup System, Residual Heat Removal System, and Standby Service Water System which perform the same functions as the CSRS, LPCRS, and HPSWS.

Finally, transient induced LOCAs were treated as special small LOCA initiators for the Grand Gulf event tree. Sequences which developed into transient induced LOCAs with unavailability of the Power Conversion System were transfered from the transient tree (refer to Appendix A2) to the LOCA event tree and were analyzed as small LOCAs. Transient induced LOCAs at Peach Bottom were developed completely on the transient event tree.

Table A1-1. Alternate Equipment Success Combinations for Functions Incorporated into the Grand Gulf LOCA Event Tree

LOCA Size	Reactor Subcriticality	Emergency Core Cooling (1)	Early Containment Overpressure Protection	Late Containment Overpressure Protection (Residual Heat Removal)	Post Accident Radioactivity Removal
Greater than 13.5 inches "A" LOCA	Reactor Protection System (RPS) Required	High Pressure Core Spray or Low Pressure Core Spray or 3 of 3 Low Pressure Coolant Injection System Trains	Vapor Suppression System (VSS)	Suppression Pool Makeup System (SPMS) and Residual Heat Removal train A and Standy Service Water (SSWS) train A in suppression pool cooling mode or SPMS and RHR train B and SSWS train B in suppression pool cooling mode	Vapor Suppression System (VSS)
Less than 13.5 inches "S" LOCA		Reactor Core Isolation Cooling System or High Pressure Core Spray or the Automatic Depressurization System (ADS) and Low Pressure Core Spray or ADS and 2 of 3 Low Pressure Coolant Injection System trains			

(1) No credit was given for the Power Conversion System after LOCAs (except transient induced LOCAs) since the Main Steam Isolation Valves will be interlocked closed due to high drywell pressure.

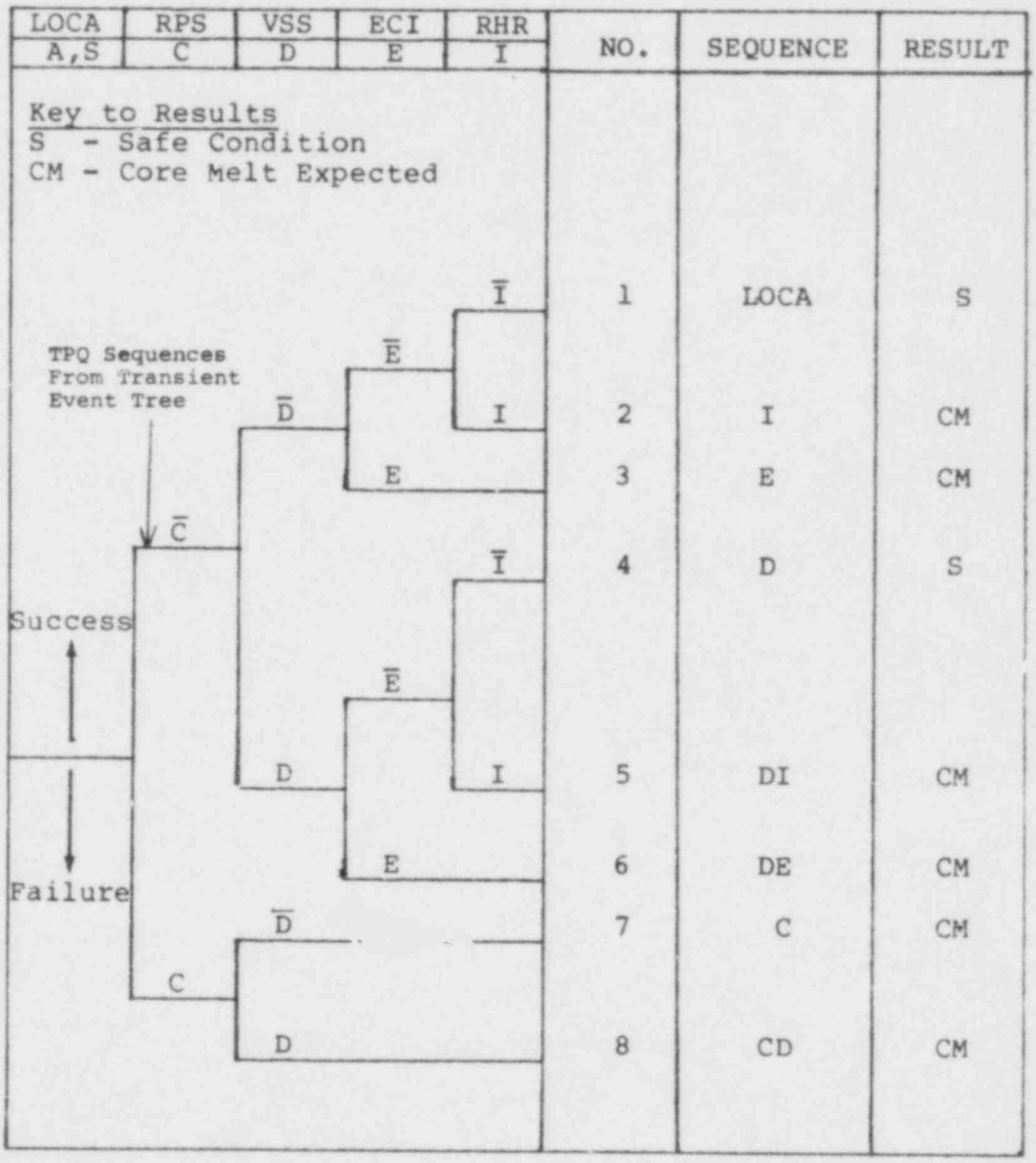
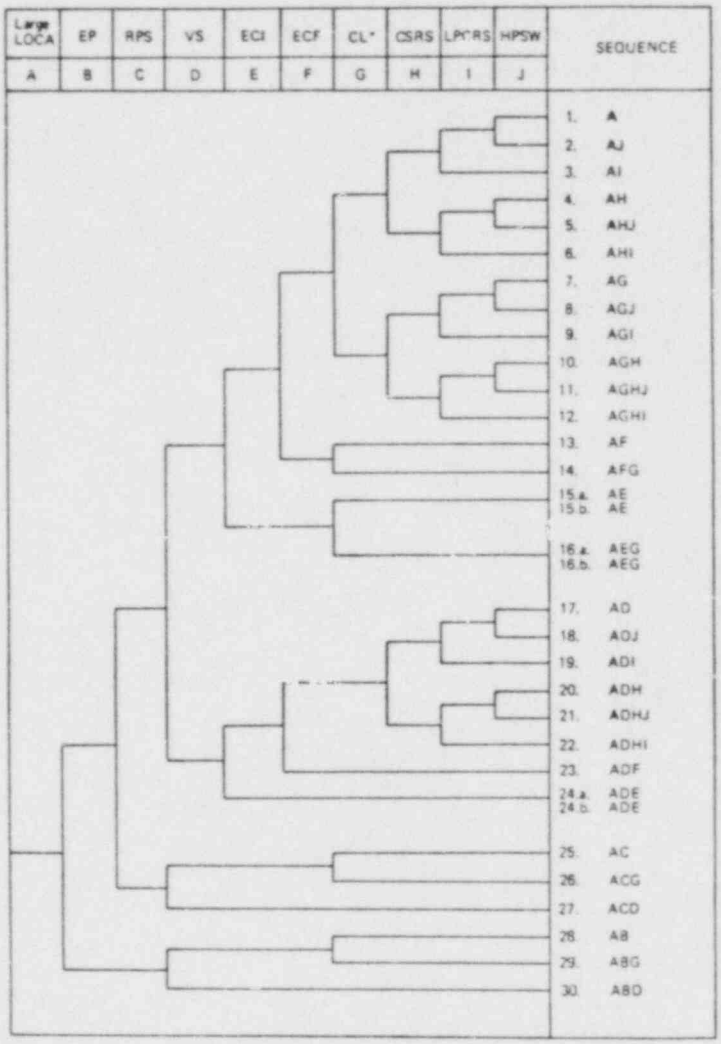
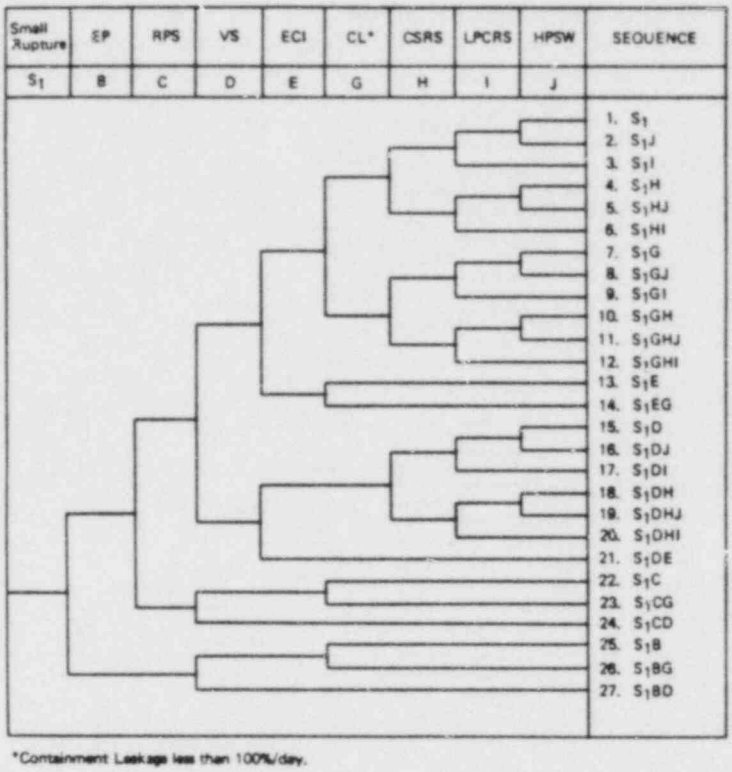


Figure A1-1. Grand Gulf LOCA Event Tree



*leakage less than 100%/day

Figure A1-2. Peach Bottom Large LOCA Event Tree



*Containment Leakage less than 100%/day.

Figure A1-3. Peach Bottom Small LOCA (S_1) Event Tree

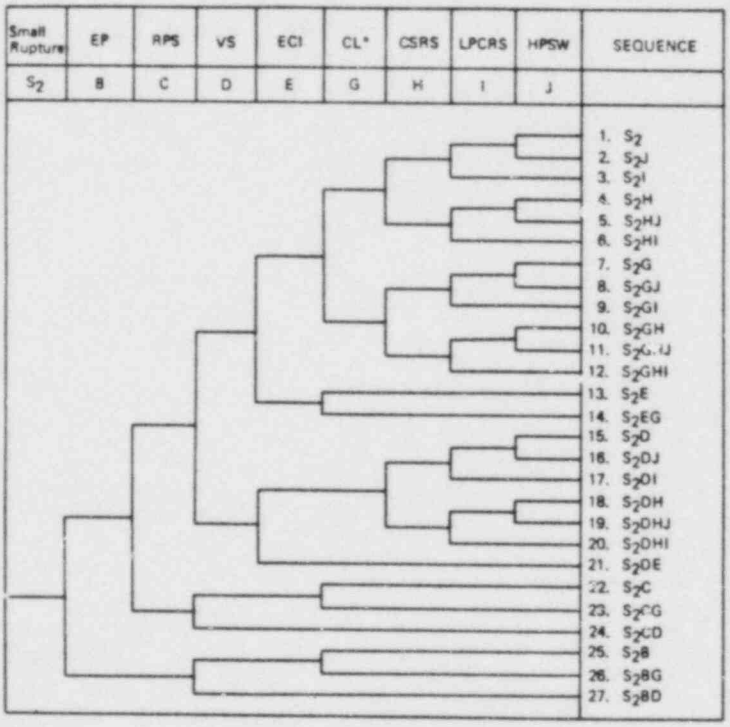


Figure A1-4. Peach Bottom Small LOCA (S_2) Event Tree

APPENDIX A2

TRANSIENT EVENT TREE - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf transient event tree is intended to apply to all anticipated transients requiring reactor shutdowns from power operation that are not a result of a large or small LOCA. The tree shows in a logical manner those combinations of systems operation that will adequately cool the core and those combinations that will result in core melting.

The Grand Gulf transient event tree is displayed in Figure A2-1. For comparison, the Peach Bottom transient event tree is shown in Figure A2-2. A discussion of the functions of the Grand Gulf plant systems perform following a transient is discussed in Section 2.1. The Grand Gulf transient event tree is explained in detail in Section 2.2. Following, in Section 3, a comparison of the Grand Gulf and Peach Bottom transient event trees is made.

2.0 GRAND GULF TRANSIENT EVENT TREE

2.1 Event Tree Functions

The functions that must be performed following a transient to preclude core damage are:

a. The reactor must be made subcritical;

b. The reactor coolant pressure must be limited to a value that will not cause the failure of the reactor coolant pressure boundary;

c. An adequate coolant inventory must be maintained within the reactor vessel; and

d. The shutdown core heat energy must be transferred to the environment.

Following a transient, it is important to immediately stop the fission process in the core. This function is automatically provided by the Reactor Protection System (RPS) which simultaneously inserts all control rods into the core. This function can also be provided by a recirculation pump trip and certain operator actions.

The pressure limiting function is performed by the safety valves and the safety/relief valves. These valves must open when RCS pressures rise high enough and close properly when RCS pressures decrease. Since the safety/relief valves discharge below the surface of the suppression pool, vapor suppression and radioactivity removal are assumed to be accomplished in a transient sequence until the reactor vessel head fails.

Several systems are used to provide emergency core cooling after a transient. These are the Power Conversion System (PCS), the High Pressure Core Spray (HPCS), the Reactor Core Isolation Cooling System (RCICS), the Low Pressure Core Spray (LPCS), and the Low Pressure Coolant Injection System (LPCIS). These systems deliver water to the core to prevent excessive fuel cladding temperatures and possible core damage. The Automatic Depressurization System (ADS) is needed for emergency LPCS and LPCI operation since they are low pressure systems.

The Power Conversion System and the Residual Heat Removal System (RHRS) working with the Standby Service Water System (SSWS) are available to transfer heat from the reactor to the environment. Failure of these systems to remove decay heat will eventually cause the primary containment to overpressurize.

A summary of the systems required to perform ESF functions during transients is given in Table A2-1.

2.2 Event Tree Definitions and Tree Development

The Grand Gulf transient event tree is displayed in Figure A2-1. The systems which perform the four functions make up the event tree headings. Dependencies between these systems dictate the event tree structure. A single transient event tree was deemed to be an adequate representation for all transient initiating events considered. A discussion of the heading definitions and tree structure follows.

2.2.1 Events T_1 and T_{23} - Anticipated Transients Requiring a Rapid Reactor Shutdown (AT)

Two different transients were chosen to represent a spectrum of transient initiators at Grand Gulf. These were designated:

T_1 - Reactor shutdown initiated by a loss of offsite power occurring at a frequency of .2 per reactor year.

T_{23} - Reactor shutdowns initiated by a loss of the power conversion system caused by other than a loss of offsite power and reactor shutdowns initiated by other causes in which the power conversion system is initially available. The frequency of this transient is 7 per reactor year.

It is clearly seen that the T_{23} transient initiator is a combination of the RSS T_2 and T_3 transients. The T_2 and T_3 transients can be combined at Grand Gulf since the transient event tree structure and event probabilities are the same for both initiators.

2.2.2 Event C - Reactor Subcriticality (RS)

Reactor subcriticality can be accomplished after a transient in one of two ways, either by the Reactor Protection System (RPS), or by the combination of a recirculation pump trip and certain operator actions to shut down the reactor. The RPS is automatically initiated if certain monitored variables exceed their setpoints and will cause all control rods to be inserted into the core. The unavailability of the RPS is discussed in Appendix B1. The failure of the recirculation pump trip and the operator actions to render the reactor subcritical is controlled by the probability that the operator will fail to manually initiate the Standby Liquid Control System or manually initiate insertion of the control rods. Based on the analysis done in the RSS, this probability was assessed to be 10^{-1}. Therefore, the value used in the transient sequence analysis for Event C is 10^{-1} times the calculated RPS unavailability given in Appendix B1. This gives values of 7.7×10^{-7} for T_{23} transients and 5.8×10^{-7} for T_1 transients.

The Mississippi Power & Light Company has committed itself to make certain design changes in the Reactor Protection System and the Standby Liquid Control System (SLCS) sometime after Grand Gulf Unit 1 starts up. One of the changes will make the SLCS an automatic system independent of any operator action. Implementation

of an automatic SLCS would greatly reduce the probability of anticipated transients without scram. However, since the SLCS will be a manually initiated system at startup and for some undetermined time after startup, it was decided not to give credit for future SLCS changes.

RS failure was placed immediately following the initiating event because its failure alone will result in the reactor remaining at significant power levels eventually leading to a core melt.

2.2.3 Event M - Safety/Relief Valves Open (S/R VO)

This event represents the failure of the safety/relief valves to open to limit reactor coolant pressure following the initiating transient. This event is independent of all others, and, as in the RSS, the probability of such an event was assessed to be negligible. As in the RSS, it was assumed that at least one safety/relief valve is demanded each time there is an initiating transient.

2.2.4 Event P - Safety/Relief Valves Reclose (S/R VR)

The safety/relief valves that open as a result of a transient must reclose to prevent discharge of an excessive quantity of reactor coolant to the suppression pool. For success, all of the safety/relief valves must reclose. As in the RSS, the failure probability of this event has been estimated to be 1.0×10^{-1}.

The RSS safety/relief valve failure to reclose probability was calculated using operating plant data. SRVs in operating plants have usually been three-stage Target Rock valves. Newer plants, such as Grand Gulf, will employ SRVs significantly different from

the Target Rock valves and, according to General Electric, will have failure to reclose probabilities of approximately .02. It was decided, however, for this study to use the RSS value since no operational data for the new valves is as yet available.

2.2.5 Event Q - Power Conversion System (PCS)

The Power Conversion System is designed to maintain the water inventory in the reactor vessel and to reject fission product decay heat to the environment. Successful operation of the PCS is defined as one complete condensate-feedwater path being operable to deliver water from the condenser hotwell to the reactor vessel. In addition to this, the main steam isolation valves must be open and the Condenser Circulating Water System and the steam jet air ejectors must be operating.

Failure of the PCS was considered for two cases: failure during the early injection phase of an accident and failure during the long-term residual heat removal phase.

As in the RSS, it is assumed that emergency coolant injection must begin within about one-half hour after the initiating transient in order to prevent a core melt. Therefore, for sequences where all ECCS injection fails (TQUV or TPQE), event Q was defined as failure of the PCS to supply makeup water within about one-half hour. RSS values of 1.0×10^{-2} for T_{23} initiators and 2.0×10^{-1} (Boolean term LOPNRE) for T_1 initiators were used for the event Q unavailabilities for TQUV sequences.

It has been assumed that the Power Conversion System will be interrupted shortly after a sequence involving a stuck-open relief valve and loss of all coolant injection (TPQE) and therefore must be recovered to provide coolant

injection. The PCS will be interrupted when the Main Steam Isolation Valves (MSIVs) close (MSIV closure on low reactor water level or steam pressure is expected). PCS recovery will depend on: (1) the reopening of the MSIVs, (2) reestablishing the condenser vacuum, if needed, (3) restoration of offsite power (T_1 transients), and (4) switchover to the auxiliary steam supply for the Steam Jet Air Ejectors (which maintain condensor vacuum) when primary steam pressure drops below approximately 150 psia. Since core melt for this sequence begins at 71 minutes and some of the recovery actions take a long time to accomplish (.3 to 2 hours for getting the MSIVs open according to utility information), no credit was given for the PCS (the probability of Q = 1.0) for TPQE sequences.

If emergency coolant injection succeeds after a transient, then residual heat must be removed from the containment within about 30 hours to prevent core melt. For sequences where ECCS injection succeeds and residual heat removal fails (TQW, TQUW, and TPQI), event Q was defined as failure of the PCS to remove decay heat from the containment in the specified time. RSS values of 7.0×10^{-3} for T_{23} initiators and 2.0×10^{-2} (Boolean terms LOPNRE*LOPNRL) for T_1 initiators were used for the event Q unavailabilities for this case.

The RSS unavailabilities used for event Q for T_{23} initiators were derived by considering the probability of failing to recover the PCS if it is already in a failed state and the probability of PCS failure given that it was initially operating.

The unavailabilities for event Q for T_1 sequences are dependent on the recovery of offsite power. For the case where injection

fails and the safety/relief valves reclose (T_1QUV), offsite power must be restored in about one-half hour for the PCS to successfully terminate the accident. Given that early injection succeeds, offsite power must be restored in about 30 hours for the PCS to successfully terminate the accident. Boolean terms representing nonrecovery of offsite power were therefore used to incorporate the electric power dependency shared by the PCS and other systems into the analysis. These two Boolean terms used to define event Q for T_1 sequences are:

Q = LOPNRE (1/2 hour case, T_1QUV sequences) ,

and

Q = LOPNRE*LOPNRL (30 hour case, T_1QW, T_1QUW, and T_1PQI sequences)

and appear in other system equations.

Since the PCS provides for both injection and long-term heat removal, successful PCS operation after a transient leads to a safe condition on the event tree.

The event tree failure path after the occurrence of events P and Q was not developed further on the transient event tree. A stuck-open safety/relief valve was judged to constitute a small LOCA. Sequences involving a stuck-open relief valve and failure of the Power Conversion System were therefore transferred to and continued on the Grand Gulf LOCA event tree and analyzed as a small (S) LOCA.

2.2.6 Event U - High Pressure Core Spray or Reactor Core Isolation Cooling (HPCS or RCICS)

Successful operation of either the High Pressure Core Spray (HPCS) or the Reactor Core Isolation Cooling System (RCICS)

will maintain an adequate coolant inventory in the reactor vessel. For success, operation of either of these systems must be initiated within about 30 minutes of the initiating event. System unavailabilities for the HPCS and RCICS are calculated in Appendices B5 and B6, respectively.

A Boolean representation of event U is therefore:

$$U = HPCS*RCICS \quad .$$

Successful long term operation of either the HPCS or RCICS is assumed to depressurize the reactor vessel. Therefore, given success of event U, the Automatic Depressurization System is not needed to reduce system pressure to the point where the low pressure systems may operate.

2.2.7 Event V - Low Pressure Emergency Core Cooling Systems (LP ECCS)

Successful operation of the low pressure ECCS to maintain an adequate water inventory in the reactor vessel requires both of the following:

a. That the operator activates the Automatic Depressurization System (ADS) to reduce the reactor system pressure to values at which low pressure ECCS systems can operate.

b. That the Low Pressure Core Spray (LPCS) or two of three Low Pressure Coolant Injection (LPCI) loops operate within a half hour after the initiating event.

Using the above criteria, a failure definition can be established for the low pressure ECCS. This, in Boolean form, is:

$$\text{LP ECCS} = \text{ADS} + \text{LPCS}*(\text{LPCIA}*\text{LPCIB} + \text{LPCIA}*\text{LPCIC} + \text{LPCIB}*\text{LPCIC}),$$

where LPCIA represents LPCI train A, etc.
The above system failures (ADS, LPCS, etc.) represent the inability of the systems to perform as required and includes hardware, maintenance, and human failures. Refer to Appendix B. Choices for event V are given only after event U failure, since successful high pressure injection precludes the necessity for low pressure injection.

2.2.8 Event W - Residual Heat Removal (RHR)

Choices for event W are given after successful high or low pressure injection (sequences $TQ\overline{U}$ and $TQU\overline{V}$). The Residual Heat Removal System is needed to remove decay heat from the containment within 30 hours for these sequences. This is due to the fact that intermittent safety/relief valve operation, RCIC turbine exhaust, and/or ADS actuation will release enough heat to the suppression pool to cause the containment to overpressurize and possibly fail. No choice is given for event W after the success of the PCS (sequence $T\overline{Q}$) since decay heat will be removed by the condenser.

The RHRS has two heat removal trains (A and B); only one of which is required to operate for RHR success. Each train can operate in two modes. In the suppression pool cooling mode, water is circulated from the suppression pool, through the RHR heat

exchangers, and back to the suppression pool. The Standby Service Water System (SSWS) is required in this mode to deliver cooling water to the secondary sides of the RHR heat exchangers. In the steam condensing mode, steam, driven by the RCICS, is condensed in the RHR heat exchangers and heat is removed by the SSWS. RHRS failure is therefore the inability of both RHR trains to remove heat by one of the two heat removal modes. In Boolean terms,

W = (RHRA + SSWA)*(RHRB + SSWB)*(RCICS + (SCA + SSWA)*(SCB + SSWB)).

The terms RHRA and RHRB represent RHRS suppression pool cooling mode failure of trains A and B. The terms SCA and SCB represent RHRS steam condensing mode failure of trains A and B. The terms SSWA and SSWB represent SSWS failure of trains A and B.

For transient sequences involving event W, an additional non-recovery term was added. Containment failure and subsequent core melt is expected to occur in 30 hours following residual heat removal failure according to Battelle Columbus Laboratories. Containment failure is predicted to occur from an overpressure caused by gas generation. It is assumed that an attempt will be made to restore or repair any components necessary for residual heat removal during this period. The probability that repairs are not completed within 30 hours given that the mean repair time is 19 hours is conservatively estimated by an expotential repair distribution,

$$P(\text{RHRS not repaired}) = \exp(-30/19) = .21$$

This nonrecovery factor was incorporated into all transient sequences involving Event W, failure of residual heat removal.

3.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM TRANSIENT EVENT TREES

As in the RSS for Peach Bottom, a single transient event tree was decided to be adequate to represent transient events at Grand Gulf. Some of the event definitions change, however, depending on the transient being considered.

The Peach Bottom and Grand Gulf transient event trees are very similar in structure. The only differences are in how the case of a stuck open relief valve is handled and how the feedwater/power conversion systems are treated.

In the RSS, sequences involving a stuck open relief valve (event P) were developed and quantified on the transient event tree. These sequences are treated as special events on the Grand Gulf transient tree. All transient induced LOCAs which include failure of the Power Conversion System start on the transient event tree and transfer to the LOCA tree after events P and Q. Once on the LOCA tree, the sequences are analyzed as small (S) LOCAs.

Finally, in the RSS, loss of feedwater and the Power Conversion System were treated as two different events. Event Q, for Peach Bottom, represented failure of feedwater injection drawing water from the condensate storage tank. Event W represented failure of the Residual Heat Removal Systems and the Power Conversion System to reject decay heat to the environment. For Grand Gulf, it was decided that successful feedwater injection implies successful condenser operation since it is likely that a fault that would

trip one would trip the other. Therefore, event Q on the Grand Gulf transient event tree was defined to be the failure of the PCS (feedwater and condensate) and event W was defined as RHRS failure. Since PCS operation provides for both injection and residual heat removal, sequences where the PCS is successful (event Q) lead to non-core melt conditions. The occurrence of event Q is defined as the failure of the PCS to reject decay heat to the environment in the required time (one half hour when ECCS injection fails and about 30 hours when ECCS injection succeeds).

Table A2-1. Alternate Equipment Success Combinations for Functions Incorporated into the Grand Gulf Transient Event Tree

Reactor Subcriticality	Reactor Coolant System Over-pressure Protection	Emergency Core Cooling	Residual Heat Removal
Control rods inserted into the core by the Reactor Protection System. or Recirculation pump trip and operator actions to manually shut down the reactor.	Safety/relief valves open when demanded and then reclose.	Power Conversion System or High Pressure Core Spray or Reactor Core Isolation Cooling System or Automatic Depressurization System (ADS) and Low Pressure Core Spray or ADS and 2 of 3 Low Pressure Coolant Injection System Trains	Power Conversion System or Residual Heat Removal (RHR) train A and Standby Service Water System (SSWS) train A in suppression pool cooling mode or RHR train A and SSWS train A in steam condensing mode or RHR train B and SSWS train B in suppression pool cooling mode or RHR train B and SSWS train B in steam condensing mode

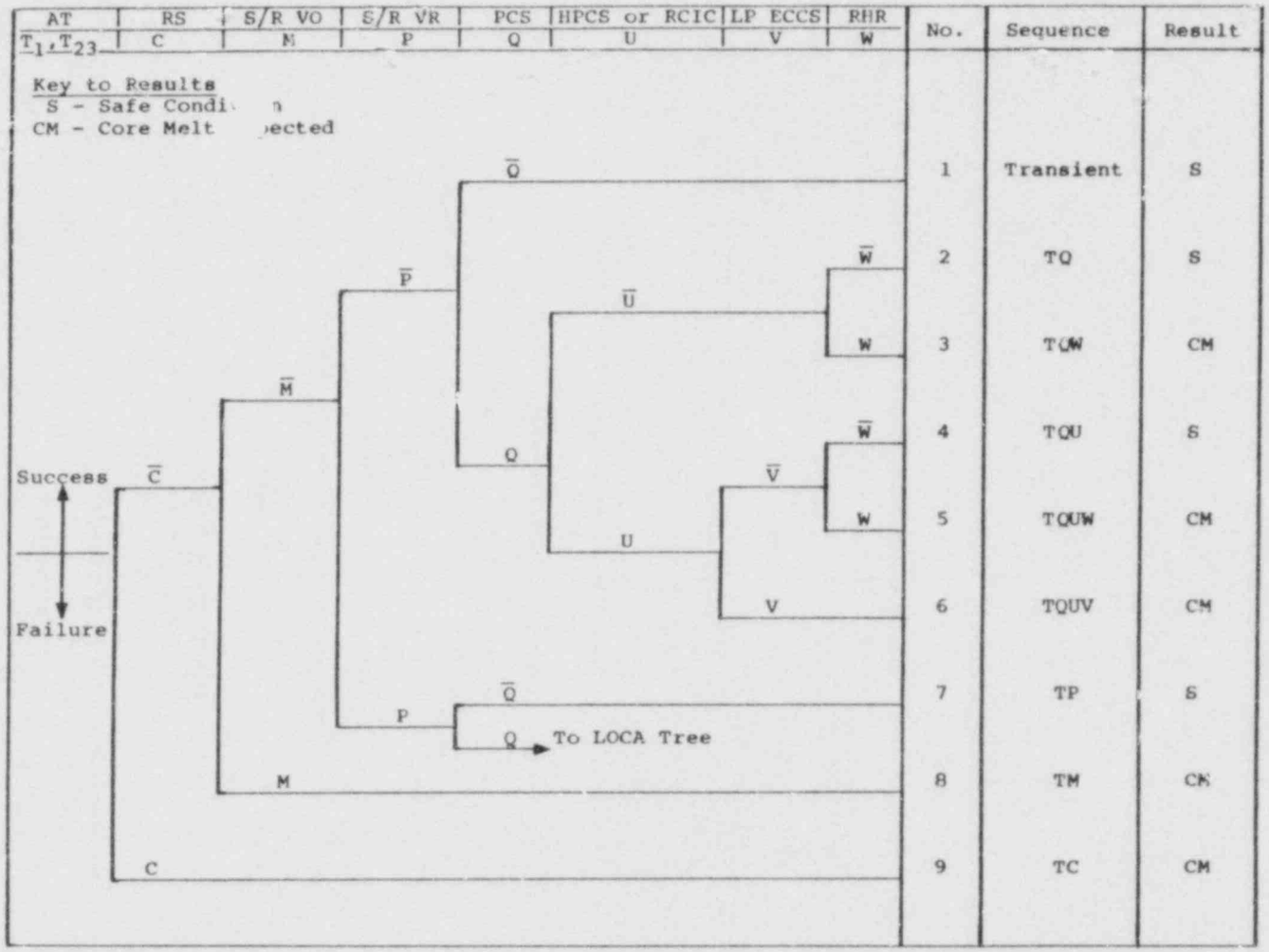

Figure A2-1. Grand Gulf Transient Event Tree

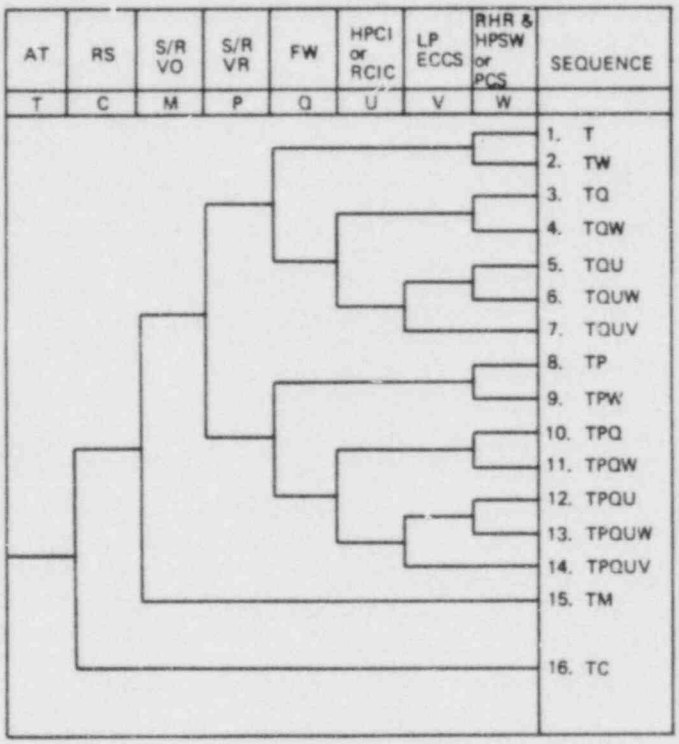

Figure A2-2. Peach Bottom Transient Event Tree.

APPENDIX B1

SURVEY AND ANALYSIS

REACTOR PROTECTION SYSTEM (RPS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf Reactor Protection System (RPS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The RPS designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report, respectively. A comparison of the two reactor protection systems is given in Section 4. RPS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a determination of the RPS unavailability used in the Grand Gulf sequence analyses.

2.0 GRAND GULF RPS DESCRIPTION

The RPS consists of the Reactor Protection Logic System (RPLS) and the Control Rod System (CRS).

2.1 Reactor Protection Logic System Description

The RPLS initiates a rapid, automatic reactor shutdown (scram) if the monitored plant variables exceed pre-established limits. The system is arranged as two separately powered trip systems and has a one-out-of-two twice logic scheme. The RPLS overrides all operator actions and process controls and is based on a fail-safe design; loss of AC power will result in trip initiation.

The RPLS includes the motor-generator power supplies, sensors, relays, bypass circuitry, and switches that cause rapid insertion of control rods (scram) to shut down the reactor. The system consists of two separate trip systems (A and B), each powered by its own motor generator set (120 VAC). Alternate power is available

to either RPLS bus. Each trip system has two logics arranged as shown in Figure B1-1.

Four independent sensor trip channels monitor the following process variables: Neutron Monitoring System, Reactor Pressure, Reactor Vessel Low Water Level, Turbine Stop Valve, Turbine Control Valve, Main Steam Line Isolation Valves, Scram Discharge Volume, Drywell Pressure, Main Steam Line Radiation Monitors, and Reactor Vessel High Water Level.

There are four trip logic divisions; A, B, C and D. Trip logic divisions A and C (trip system A) actuator output signals are connected to one pilot scram valve solenoid while divisions B and D (trip system B) are connected to the other pilot scram valve solenoid. Both solenoids, normally energized, must be deenergized in order for a scram to occur.

Each logic division receives input signals from at least one channel for each monitored variable. Four channels for each monitored variable are required, one for each of its four automatic or manual logics.

Channel and logic relays are fast-response, high-reliability relays. All relays are selected so that the continuous load will not exceed 50 percent of the continuous duty rating. The system response time, from the opening of a sensor contact up to and including the opening of the trip actuator contacts, is less than 50 milliseconds.

Each logic provides two inputs into each of the actuator logics of one trip-system. Either of the two logics can produce a trip-system trip. The actuator logics of both trip systems

must be tripped in order to produce a scram. Thus, the overall logic is termed one-out-of two taken twice.

Four scram buttons, one for each division logic (A1, A2, B1 and B2), are arranged in two groups (A1-B1 and A2-B2). The manual scram logic is the same as the automatic scram logic.

Scram reset is possible through the use of four redundant reset switches. Each switch is used to momentarily bypass the seal-in contacts of the final actuators of this reactor shutdown system. If a single channel is tripped, the reset is accomplished immediately upon operation of the reset switch. If a scram condition is present, manual reset is prohibited for a 10 second period to allow the control rods to insert completely. Actuation of all four switches is required to reset, following a scram and 10 second time delay.

2.2 Control Rod System Description

The CRS consists of the control rods and the Control Rod Drive (CRD) system. The CRS inserts the negative reactivity necessary to shut down when a scram is initiated by the RPLS. Each control rod is controlled individually by a hydraulic control unit (HCU). When a scram signal is received, high pressure water stored in an accumulator in the HCU or reactor pressure forces its control rod into the core. Each of the 193 control rods consists of a sheathed cruciform array of stainless steel, boron-carbide powder filled tubes. A velocity limiter, protecting against a rod drop accident, is located in the bottom assembly of each control rod.

The CRD for each rod consists of locking piston control rod driver mechanism (drive), which positions the control rod in the

core, is a double-acting, mechanically latched, hydraulic cylinder using water as its operating fluid (Figure B1-2). The individual drives, mounted on the bottom head of the vessel are capable of inserting or withdrawing a control rod at a slow, controlled rate, as well as providing rapid insertion when required. A mechanism on the drive locks the control rod at a 6-inch increment of stroke over the length of the core. A coupling spud at the top end of the drive index tube is locked into the base of the control rod by the rod's weight.

Each drive has an internal ballcheck valve which can allow reactor pressure to be admitted under the drive piston. If the reactor pressure is above 600 psi, this valve ensures rod insertion in the event the accumulator is not charged or the inlet scram valve fails to open. The drive holds its control rod in distinct latch positions until the hydraulic system actuates movement to new position.

The CRD hydraulic system (Figure B1-3), consisting of pumps, filters, valves, and piping, supplies and controls the pressure and flow to and from the drives through hydraulic control units (HCU). The water discharged from the drives during a scram flows through the HCUs to the scram discharge volume. A check valve in each HCU prevents reverse flow from the discharge volume to the drive.

The scram discharge volume consists of two headers which are connected to the HCUs. One header receives flow from 96 HCUs, and the other header receives flow from 97 HCUs. Flow entering the scram discharge volume headers drains to an instrument volume.

The header piping is sized to receive all the water discharged by the drives during a scram, independent of the instrument volume. Six liquid-level switches activated by transmitters connected to the instrument volume, monitor the volume for abnormal water level. They are set at three different levels. At the lowest level, a switch actuates to inducate that the volume is not completely empty during post-scram draining or to indicate that the volume starts to fill through leakage accumulation at other times during reactor operation. At the second level, one switch produces a rod withdrawal block to prevent further withdrawal of any control rod, when leakage accumulates to half the capacity of the instrument volume. The remaining four switches are interconnected with the trip channels of the reactor trip system and will initiate a reactor scram should water accumulation fill the instrument volume.

Each HCU furnishes pressurized water, on signal, to a drive unit. A HCU consists of manual, pneumatic, and electrical valves, an accumulator; related piping, electrical connections, filters, and instrumentation. Each HCU has two pilot scram valves and two scram valves. The pilot scram valves, solenoid operated (RPLS), control the air supply to the scram valves for each control rod. One of the pilot scram valves for each rod is controlled by actuator logic A, the other by actuator logic B. With either pilot scram valve energized, air pressure holds the scram valves closed. The scram valves control the supply and discharge paths for control rod drive water.

The accumulator, a hydraulic cylinder with a free floating piston, stores sufficient energy to fully insert a control rod at any vessel pressure.

Two DC solenoid operated backup scram valves provide a second means of controlling the air supply to the scram valves for all control rods. These valves can insert any withdrawn rods regardless of the action of the pilot valves.

2.3 System Operation

During normal operation all sensor and trip contacts essential to safety are closed; channels, logics, and actuators are energized.

When conditions exist such that any of the various monitored process variables have exceeded predetermined specifications (Table B1-1), the associated channel sensors will open.

When a channel sensor trip operates, its relay deenergizes its actuators which deenergizes the scram pilot valve solenoid associated with that trip system logic. In the same manner, the other pilot scram valve must also be deenergized in order for a scram to occur. With both pilot solenoids deenergized, the scram valves open, allowing instrument air to be bled from them. This permits accumulator pressure to be admitted under the drive piston, and the area over the drive piston is vented to the scram discharge volume. This upward force gives the rod a high initial acceleration, providing a large force to overcome friction.

When trip systems A and B are both tripped, the normally deenergized backup scram valves are energized, these valves vent the air supply for the scram valves, thus, initiating insertion of

any withdrawn control rods. To manually initiate a scram, two of the scram buttons, one from each trip system, must be depressed.

During normal plant operation, the scram discharge volume is empty and vented to atmosphere through its open vent and drain valve. When a scram occurs, upon a signal from the safety circuit, these vent and drain valves are closed to conserve reactor water. During a scram, the scram discharge volume partly fills with water discharged from above the drive pistons. After scram is completed, the control rod drive seal leakage from the reactor continues to flow into the scram discharge volume until the discharge volume pressure equals the reactor vessel pressure. When the initial scram signal is cleared from the RPLS, the scram discharge volume signal is overridden, and the scram discharge volume is drained and returned to atmospheric pressure.

The RPS can be tested during reactor operation by five separate tests, including: (1) manual scram test - verifies the ability to deenergize all eight groups of scram pilot valve solenoids by using the manual scram push button switches; (2) actuator test - verifies the ability of each logic to deenergize the actuator logics associated with the parent trip system; (3) calibration of neutron monitoring system; (4) single rod scram test - verifies the capability of each rod to scram; (5) application of a test signal to each PRLS channel - verifies that a logic trip will result, and that the channel circuitry is independent.

3.0 PEACH BOTTOM RPS DESCRIPTION

The RPS consists of two subsystems: the Reactor Protection Control Rod System (RPCRS) and the Reactor Protection Logic System

(RPLS). The RPCRS, comprised of 185 control rods, associated drive units, and hydraulic control modules, provides for the rapid insertion of the control rods when a trip system exists. The RPLS, comprised of two independent trip systems, A and B, senses improper operating conditions and removes power from the control rod drives, thus initiating a reactor trip. A trip is the operating function which consists of the simultaneous insertion of all control rods to shut down the reactor. The control rods of the RPCRS are arranged with each rod having its own rod drive unit (hydraulic actuator) and hydraulic control module. A schematic of the control rod hydraulic system is shown in Figure B1-4. The trip pilot valves normally energized, are deenergized by a trip of the RPLS. The deenergized pilot valves open the trip valves and direct stored water from the trip accumulator (1500 psi) to the insert port of the control rod drive, thus resulting in rapid insertion of the control rods into the reactor core.

The air pressure in the trip pilot valve air header is controlled by the back-up trip valves. A RPLS trip deenergizes the K13 and K14 contactors, thus energizing the back-up trip valves. They shut off the instrument air supply and allow the pressurized air in the trip pilot valve which fails to return to the deenergized position when tripped.

The hydraulic control modules are located in two locations-within the reactor building, each location on opposite sides of the reactor corresponding to the division of the rods. The water expelled from each bank of control rod drive units during a trip is discharged into separate headers located above the control

modules. During operation, water in each of the two headers drains to a trip instrument volume through a 2-inch drain line and from the volume through a normally open drain valve (CV3-13-33) to the radwaste storage tank. The trip instrument volume, a tank 12 inches in diameter and 10 feet high, is instrumented to provide an early alarm and later an automatic reactor trip if water accumulates in the volume to greater than predetermined levels. During a trip the drain valve CV3-13-33 and vent valves CV3-13-32A and CV3-13-32B are closed to prevent possible water flow from the withdrawal ports of the control rod drive units when the drive units have been stroked to the full insert position. After the trip system has been reset, the drain valve and the vent valves are opened to drain the water collected in the trip header and the trip instrument volume.

If the accumulator pressure drops below reactor pressure before complete insertion, a check valve in the control rod drive base flange will open, permitting pressurized reactor water to enter the insert port of the drive unit. This will provide sufficient force to complete the control rod insertion.

The reactor trip function, whether manual or automatic, is initiated by the RPLS. A manual reactor trip can be initiated by two manual trip push button switches located in the control room. An automatic reactor trip may be initiated by either a sensed rise in drywell pressure or a decrease in reactor water level. A third reactor trip may occur when the main steam line isolation valves (MSIV) start to close due to a further reduction in reactor water level. The high drywell pressure sensors actuate at 2.0 psig.

The reactor water level reactor trip sensors actuate when the water level recedes from 555 inches to 540 inches above vessel zero. When the water level drops to 492 inches above vessel zero, other sensors initiate the closure of the MSIVs. Limit switches on the MSIVs initiate a reactor trip.

Each independent trip system (A and B) of the RPLS is comprised of three channels (two automatic and one manual).

The sensor and logic channels, of the RPLS, detect operating variables exceeding set limits and logically validate the signals. The RPLS is a failsafe system; i.e., the system is deenergized when a reactor trip is commanded. The sensor and logic channels provide the electrical path to energize the twelve trip contactors. Both an A channel and a B channel must be tripped to initiate a reactor trip. When the trip contactors are deenergized, electrical power is removed from all trip pilot valves, thus opening the trip valves. The back-up trip valves are energized by the application of 125 VDC by the contacts of K13 and K14 which close when the contactors are deenergized.

4.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM RPS

Both systems, each consisting of a control rod system and a logic system, are designed to automatically shut down the reactor immediately at the onset of abnormal plant operating conditions.

The RPLS, essentially the same for each plant, is arranged as two separately powered trip systems and has a one-out-of-two twice locic scheme. Two manual scram switches are provided for each Grand Gulf trip system, while Peach Bottom incorporates one manual scram switch for each trip system. An important CRS failure identified

in the RSS involved plugging of the instrument volume drain valve and then having enough water accumulation in the instrument volume to prevent a successful scram. Water accumulation could occur from leakage past valves in the hydraulic control units or from annual control rod insertion tests. Faults of this type accounted for 2.9×10^{-7} of the Peach Bottom RPS unavailability.

The Grand Gulf system has redundant water level sensors in the instrument volume which will trip the reactor before water accumulation could possibly cause a scram failure. Water accumulation is also alarmed in the control room. For these reasons, scram failure by this method is expected to be negligible at Grand Gulf.

The principal contributors to the RPS unavailability for both Grand Gulf and Peach Bottom are mechanical failures of three adjacent rods to enter the core and a common mode failure arising from miscalibration of RPS sensor switches. The point estimate unavailability for the Reactor Protection System at Peach Bottom is 1.3×10^{-5} and was obtained by Monte Carlo simulation. The estimate for Grand Gulf's system is 7.7×10^{-6} for LOCAs and T_{23} transients and 5.8×10^{-6} for T_1 transients.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

The Grand Gulf RPS is an independent system having no commonalities with the other analyzed systems. The RPS contributes only to Event C, which is failure to render the reactor subcritical on both the LOCA and transient event trees. For LOCAs, failure of the RPS alone was assumed to cause a scram failure. As in the RSS, no credit was given for possible operator actions after a LOCA.

For transients, however, credit was given for certain operator actions which would shut down the reactor. Manual initiation of the Standby Liquid Control System and manual insertion of the control rods is included in addition to the RPS calculation in the overall analysis of Event C for transients. Refer to Appendix A2 for more details.

Failure of the RPS is defined as failure of the RPLS or CRS to cause control rod insertion after a transient or LOCA. Failure of the RPLS and CRS was included in the Event C analysis for LOCAs and T_{23} transients. For T_1 transients, only the failure of the CRS was considered since the RPLS trips on a loss of offsite power.

5.2 Determination of RPS Unavailability

The RPLS and the CRS were analyzed separately and then combined to produce a point estimate unavailability of the RPS.

The point estimate for the unavailability of the Grand Gulf RPLS is calculated to be:

$$Q_{\text{Double Failures}} = \text{(negligible)}$$

$$+\ Q_{\text{Common Mode}} = 1.9 \times 10^{-6}$$

$$Q_{\text{RPLS, Grand Gulf}} = 1.9 \times 10^{-6}$$

The operation of the RPLS is considered to be successful if the system provides a trip command to the CRS when any of the monitored plant variables exceed their preestablished limits. The RPLS, with a one-out-of-two twice logic scheme, must receive a signal from both trip systems, A and B, in order to provide a trip command (deenergize the scram solenoids).

Double failures, which reflect the inability of either trip system to provide a signal to the RPLS, include: (1) Electrical short to trip system A power bus by both channel A1 and A2 contactor solenoid windings; and (2) Electrical short to trip system B power bus by both channel B1 and B2 contactor solenoid windings.

From the RSS, the probability that any channel (A1, A2, B1, or B2) contactor solenoid winding will short is:

$$Q_{A1} = Q_{A2} = Q_{B1} = Q_{B2} = 3.6 \times 10^{-6}$$

Therefore, the double failure contribution, Q_D, to RPLS failure is estimated to be:

$$Q_D = A_{A1}Q_{A2} + Q_{B1}Q_{B2}$$

$$= (3.6 \times 10^{-6})^2 + (3.6 \times 10^{-6})^2$$

$$= 2.6 \times 10^{-11} \text{ (negligible)}$$

Common mode failure, resulting from human errors in test and calibration of sensor switches, is the principal contributor to the RPLS failure. The RSS BWR, with a logic system similar to that of Grand Gulf, had a common mode failure probability value of 1.9×10^{-6}. The RSS estimate for common mode failure was judged applicable to Grand Gulf. Thus,

$$Q_{CM} = 1.9 \times 10^{-6}$$

No single failures, triple failures, or test and maintenance procedures contributed to the RPLS failure probability.

The operation of the CRS is considered to be successful if the system inserts the control rods which are necessary to shut down the reactor when a scram is initiated by the RPLS. The RPLS deenergizes and opens the inlet and outlet scram valves in each HCU. With these valves open, accumulator pressure is admitted under the drive piston, and the area over the drive piston is vented to the scram discharge volume. Failure of the CRS is conservatively defined as the failure of any three or more adjacent control rods to be inserted on a reactor trip.

The principal contributor to the CRS failure is the failure of any three adjacent rods to insert (triple failures). The Grand Gulf CRS (193 rods) triple failure contribution, as derived for the similar BWR CRS (185 rods) in the RSS, is:

$$Q_{Triples} = 5.8 \times 10^{-6}$$

This value was used as the Grand Gulf CRS failure probability since no other failures were found to contribute significantly.

Combining the unavailabilities calculated for the RPLS and CRS result in the Grand Gulf RPS unavailability used in the sequence analysis for LOCAs and T_{23} transients.

$$Q_{RPLS,\ Grand\ Gulf} = 1.9 \times 10^{-6}$$

$$+ \quad Q_{CRS,\ Grand\ Gulf} = 5.8 \times 10^{-6}$$

$$Q_{RPS,\ Grand\ Gulf} = 7.7 \times 10^{-6} \text{ (LOCAs and } T_{23}\text{)}.$$

The RPS unavailability used for T_1 transients reflects only CRS failure since the RPS trips on a loss of offsite power. Therefore,

$$Q_{RPS,\ Grand\ Gulf} = 5.8 \times 10^{-6}\ (T_1).$$

Table B1-1. Reactor Protection System Instrumentation Specifications for Grand Gulf

Scram Function	Instrument	Trip Setting	Normal Range	Accuracy	Transient
Reactor vessel high pressure	Pressure transmitter	1065 ±11 psig	935 to 1025 psig	Repeatable within ±10 psig	150 psi/sec
Drywell high pressure	Pressure transmitter	2.0 ±0.05 psig	-2 to +2 psig	Repeatable within ±0.05 psig	20 psi/sec
Reactor vessel low water level	Level transmitter (3)	543.3 inches above vessel zero	15 to 41.5 inches above trip setting	Repeatable within ±1.5 inches	7 in/sec
Scram discharge volume high water level	Level transmitter	54 ±2 gallons	Empty	Repeatable within alarm and trip setting tolerance	Negligible
Turbine stop valve closure	Pressure transmitter	40 psig	165 psig	±2 psig	(2)
Turbine control valve fast closure	Pressure transmitter	41 psig	42-70 psig	±1 psig	N/A
Main steam line isolation valve closure	Position switch	Before 10% valve closure	Fully open to fully closed	N/A	N/A
Neutron monitoring system	See subsection 7.6.1.5				
Main steam line high radiation	Gamma detector	6x normal	(1)	(1)	(1)
Reactor vessel high water level	Level transmitter (3)	587.9 inches above vessel zero	3.1 to 29.6 inches below trip setting	Repeatable within ±1.5 inches	7 in/sec

Bypass Function	Instrument	Trip Setting	Normal Range	Accuracy	Transient
Discharge volume high water level trip bypass	N/A	Bypass switch in bypass and mode switch in shutdown or refuel	N/A	N/A	N/A
Turbine stop valve and control valve fast closure trip bypass	Pressure transmitter	Turbine first-stage pressure <30% power	0 to 100% power	Repeatable within ±20 psig	N/A
Main steam line isolation valve trip bypass	N/A	Mode Switch in shutdown, refuel, or startup	N/A	N/A	N/A

(1) See Process Monitoring System (IED)
(2) Trip fluid pressure decreases from normal to 42 psig before the stop valve begins to close.
(3) A common level transmitter is used for both high and low reactor vessel trips - separate trip units monitor the common level signal.

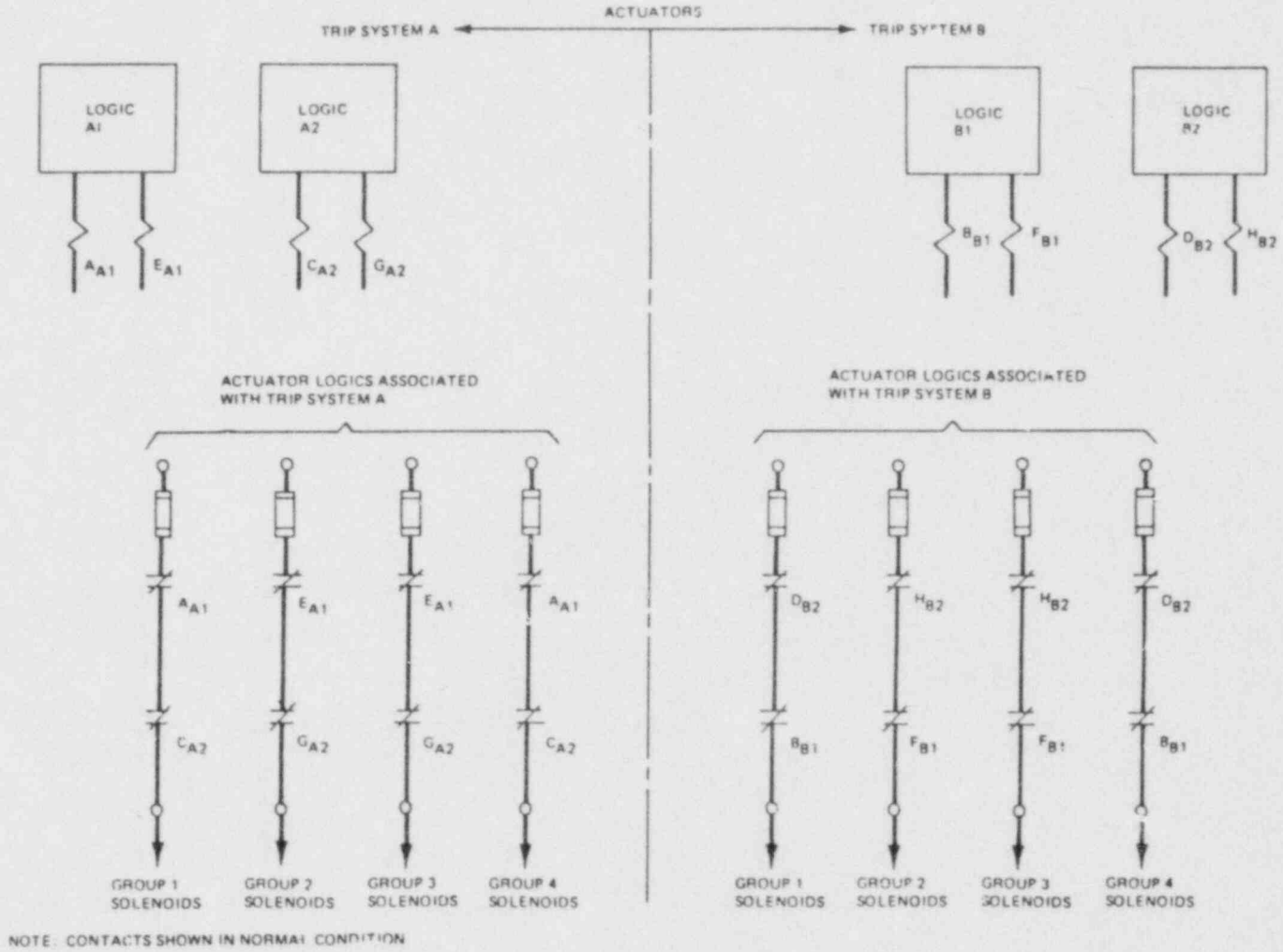

Figure B1-1. Actuators and Actuator Logics - Grand Gulf

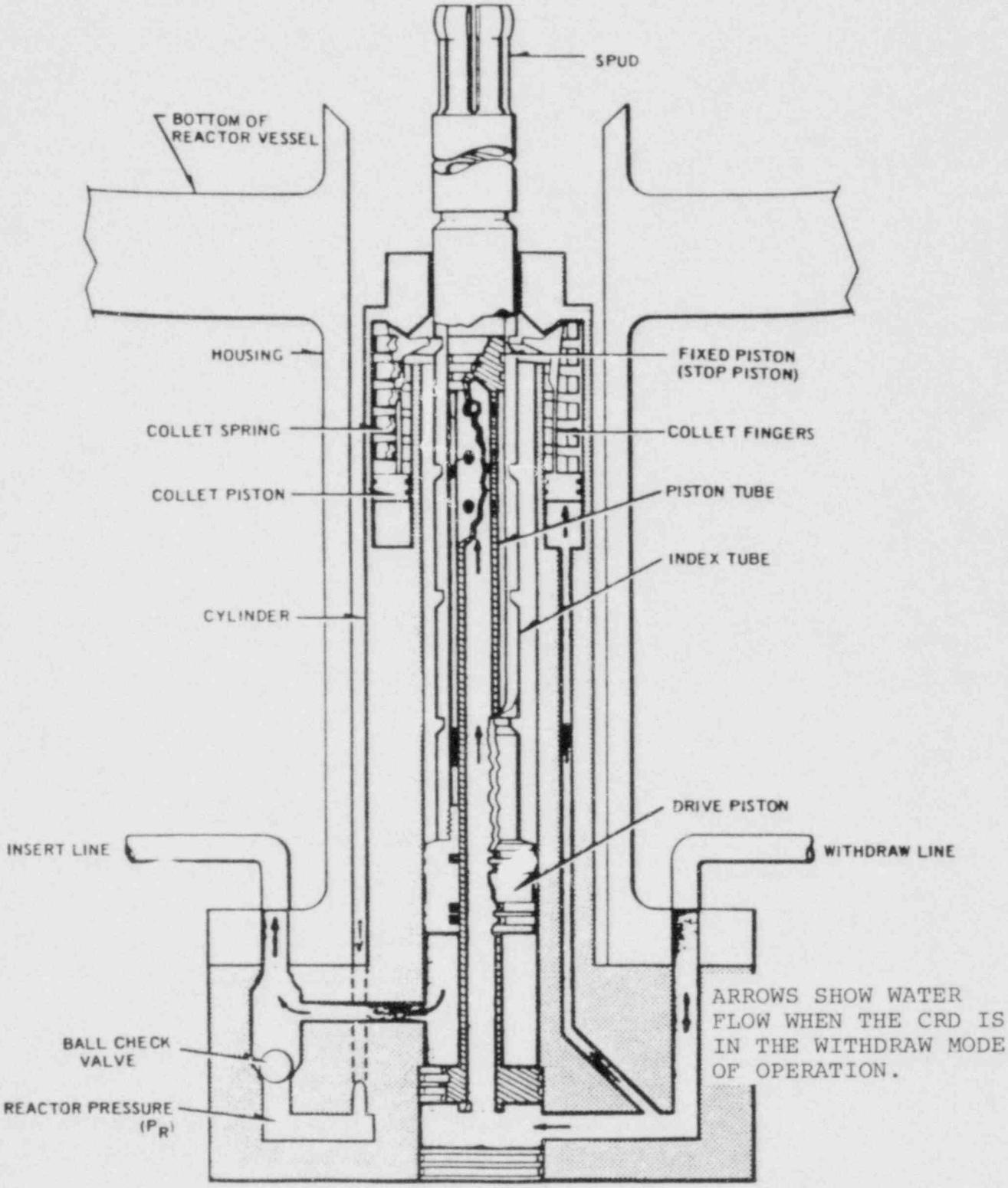

Figure B1-2. Control Rod Drive Unit - Grand Gulf

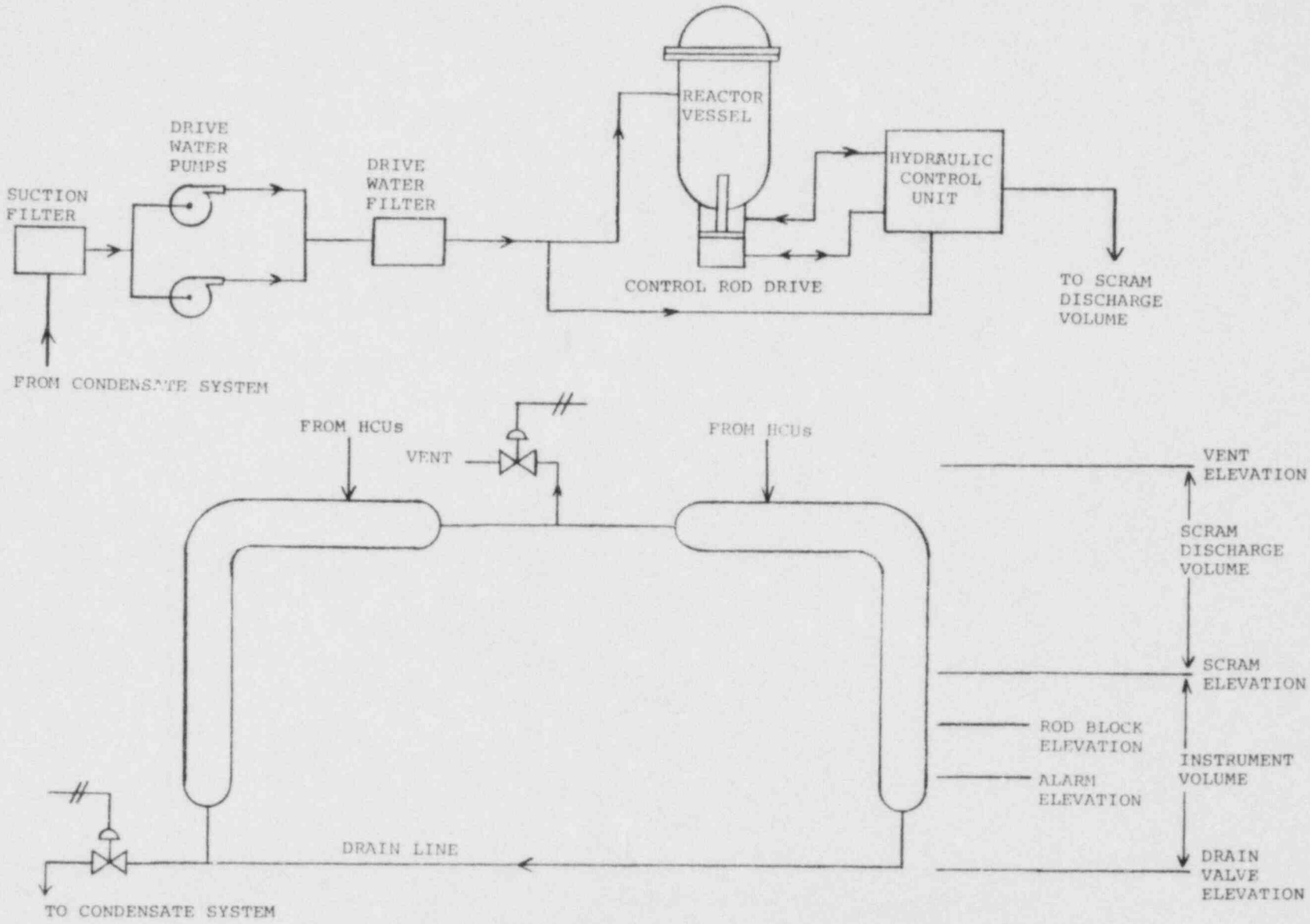

Figure B1-3. Grand Gulf Control Rod Hydraulic System

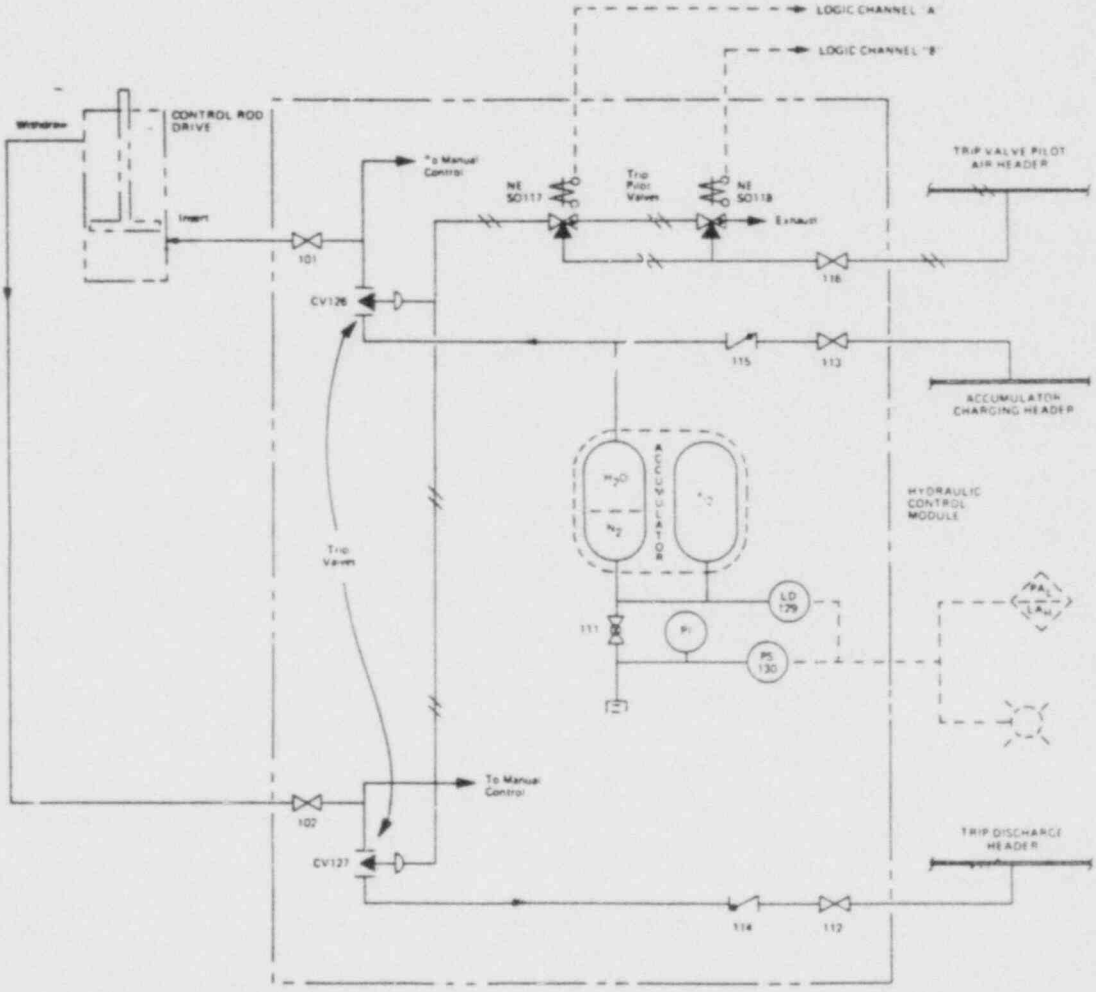

Figure B1-4. Reactor Protection System Control Rod Drive Hydraulic Schematic - Peach Bottom

APPENDIX B2

SURVEY AND ANALYSIS

EMERGENCY AC POWER SYSTEM (EPS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf Emergency AC Power System (EPS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The EPS designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report respectively. A comparison of the two emergency power systems is given in Section 4. EPS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate EPS failures into the Grand Gulf accident sequences.

2.0 GRAND GULF EPS DESCRIPTION

2.1 System Description

The Grand Gulf EPS includes the sources of, and feedpath arrangements for, AC power to mitigate the effects of transients and accidents. The EPS is designed to ensure continuous operability of the 4160 volt ESF buses and orderly control of the reactor following a LOCA and/or loss of offsite power. (See Figure B2-1.)

The following power sources are available to supply AC power:

a) Two 500 KV circuits from the 500 KV switchyard

b) One 115 KV offsite circuit

c) Six standby diesel generators (three per unit).

The preferred switching order to the 4160 volt ESF buses is (1) the 500 KV transmission network through unit service transformers #11 and #21 to ESF transformers #11 and #21 respectively, (2) the 115 KV transmission network to ESF transformer #12, and (3) the emergency diesel generators directly to the 4160 volt ESF buses.

The 500 KV switchyard includes three 500 KV overhead lines. The switchyard employs a breaker-and-a-half configuration with power provided to the ESF buses through two 500 KV/34.5 KV unit service transformers (#11 and #21) and two 34.5 KV/4.16 KV ESF transformers (#11 and #21). The offsite 500 KV power sources include (1) the Franklin 500 KV substation, (2) the Baxter Wilson 500 KV substation, and (3) the Ray Braswell 500 KV substation.

The 115 KV system consists of an overhead 115 KV line from the Port Gibson substation terminated near the plant site to an underground 115 KV cable. The 115 KV cable feeds a 115 KV/4.16 KV ESF transformer (#12).

Provisions are included for monitoring each phase of the normal 4.16 KV power supply and initiating transfer of the loads to an alternate source if the voltage in any phase falls below 70% of the nominal value. Return of the normal supply to 90% of its nominal value will initiate re-transfer following a pre-determined time delay. The purpose of the delay is to avoid re-transfer to an unstable power supply. The transfer switch receives its power from the source to which the load is being transferred.

The DC requirements for the switchyard relay and control systems are provided by two independent sets of 125 volt batteries. Each of these DC systems is supported by its own charger which has its own redundant AC power supplies.

The onsite AC power system consists of six diesel generator sets and auxiliaries required to start each diesel and to connect each generator to its bus. Diesel generators 11, 12, and 13 are dedicated to unit 1 and diesel generator 21, 22, and 23 are dedicated to unit 2.

The onsite power source of each engineered safety feature bus is the diesel generator connected exclusively to the bus. The continuous service rating of the diesel generators is 7000 KW at 4.16 KV on an 8800 hour base with 110% (7700 KW) overload permissible for 2 hours out of 24 hours.

Fuel oil is supplied directly to each diesel engine from a 550 gallon day tank. Two redundant 100% capacity fuel oil pumps, one driven by the diesel engine and the other driven by a DC motor, deliver the fuel from the day tank to the engine manifolds. The day tank permits diesel generator operation for 1-1/4 hours to 2 hours depending on load division. A 75,000 gallon fuel oil storage tank is provided for each diesel generator. Fuel oil is automatically transferred from the storage tank to the day tank via a transfer pump when then level in the day tank drops below a prescribed limit. The tank capacity is sufficient to operate the diesel while supplying maximum post-LOCA load demands for a duration of 7 days.

A diesel generator will automatically shut down in the event of (a) engine overspeed, (b) low lube oil pressure, (c) high crank case pressure, (d) generator differential, and (e) generator ground overcurrent. In addition, provisions are included for monitoring other important diesel generator characteristics such as water jacket and lube oil level and temperature, pump speed, generator frequency, etc. Departure from pre-set limits will be annunciated in the control room and/or locally.

The ESF loads of each unit are divided into three load divisions (I, II, III), each fed from an independent 4.16 KV ESF bus. Each

load division in each unit can be supplied from any one of the three ESF transformers. Each ESF bus feeds its associated 480 volt load center buses through 4.16 KV/480 V transformers. The load center buses provide power for motor control centers and other 480 volt safety loads. An independent DC system, supplying power for the control of the AC power system, is provided for each load division.

The major ESF loads for each load division are as follows:

DIVISION	BUS	LOAD (kilowatts)
I	15AA	1 LPCS Pump Motor - 1735 1 RHR Pump Motor - 890 1 Control Rod Drive Pump Motor - 360 1 Standby Service Water Pump Motor - 720
II	16AB	2 RHR Pump Motor - 890 each 1 Control Rod Drive Pump Motor - 360 1 Standby Service Water Pump Motor - 720 1 Instrument Air Compressor Motor - 300
III	17AC	1 HPCS Pump Motor - 2780

A 120 VAC Essential Instrument Power System is provided for each load division via 480V/120V transformers. The system consists of redundant distribution panels fed through transformers connected to separate ESF motor control centers. There are no bus ties or interconnections between distribution panels of different safety divisions.

A 120 VAC power system consisting of two high-inertia, AC, motor-generator (MG) sets is provided to supply power to the logic which

operates the RPS. Each MG set supplies control power to independent trip systems of the nuclear steam supply shutoff system, power range monitoring system, parts of process radiation monitoring system, and reactor protection trip system. The MG sets constitute the primary source of power to the RPS. An alternate source of 120 VAC power for the RPS is a non-essential instrument transformer. The two motor generators are supplied from two 480 volt motor control centers fed from the Division I and II buses. The status of both motor-generator sets and the instrument buses is monitored in the control room. The RPS power system is classified as non-essential because failure of the power supply causes a reactor scram. However, the power feeds to independent divisions are physically separated and feed four redundant buses.

Load shedding and load sequencing on ESF Divisions I and II is employed during a LOCA and/or a loss of offsite power. The load shedding and sequencing is performed by redundant circuit panels (one per division). The load sequencing logic controls the permissive and starting signals to motor feeder breakers so as to positively prevent an overburden on any power source by automatic load application.

2.2 System Operation

During normal plant operation, with all three ESF transformers available, each load division in each unit is supplied from a separate winding of each two-winding ESF transformer. When less than three ESF transformers are available, the six load groups (three per unit) are distributed among the remaining ESF transformers to maximize the remaining ESF capacity.

Diesel generator sets 11, 12 and 13, start automatically on loss of offsite power, low water level in the reactor, or high drywell pressure. Undervoltage bistables are used to start the diesel engines in the event of a drop in bus voltage below pre-set values for a predetermined period of time. Four low-water level switches and four drywell high-pressure switches initiate diesel start under accident conditions. One-out-of-two-twice logic is used for generating the start logic as shown in Figure B1-5.

The transfer of the diesel generators to their associated ESF buses is automatic in the event of loss of all offsite power. The diesel generator breaker is closed when the required generator voltage and frequency have been established ($\leq$ 10 seconds), after the breakers connecting the buses to the offsite sources are open and all bus loads except the ESF 480 volt load center feeders are tripped. The same signal that initiates the breaker tripping also causes all loads to be stripped from the ESF bus, except for the ESF 480 volt load center feeders. The required loads are then sequentially applied via control and timing circuits after closing of the diesel generator breaker.

The existence of the LOCA condition is signaled by redundant one-out-of-two twice sensor circuits originating in NSSS equipment. This is the same signal, isolated, which initiates the ESF and emergency core cooling provisions.

The first action after receipt of the LOCA signal removes all loads from the ESF buses at the highest (4,160 volts) voltage level except the feeders to the 480 volt load centers. At the load center level, all feeders are tripped except those supplying power to motor control centers (MCCs) which supply ESF system valve motors and

protection equipment such as RPS motor-generator sets. This ensures maximum retention of plant protection systems and minimizes delay in placing the ECCS in the proper lineup for core cooling.

The timing sequence for ECCS is the same regardless of whether the ESF buses are energized from offsite or onsite power. This makes the LOCA sequencing a function solely of when ESF bus voltage becomes available without memory of past conditions or knowledge of the present power source. When the necessary and sufficient condition of bus voltage is obtained, the sequencing logic applies the ECCS/ESF loads.

Should the bus voltage (offsite source) be lost during post-accident operation, shedding and searching for an alternate power source will occur as described below. Once voltage is restored, the LOCA sequencing procedure will repeat itself with respect to starting motor loads. Since system reset is not a function of the presence or absence of bus voltage, no change to valve positions will occur. Therefore, the restarting duty will be less severe because no MCC valve power will be required.

Redundant bus undervoltage bistables set to actuate upon experiencing 70 percent voltage, will signal loss of the preferred power to the ESF buses. When this signal is initiated in the sequencing panel, it will automatically trip and inhibit all incoming and motor feeder breakers except those to load centers and motor control centers previously defined in the LOCA description. If an alternate offsite power source can be located, this source is connected to the bus after a time delay of 2 seconds which permits the residual voltage to decay on any motor previously running.

Upon loss of preferred power the diesel generators are automatically started. If an offsite source is available and utilized, the diesel will be manually stopped by the operator. If no offsite source is available the diesel will be automatically connected to the ESF bus via the load sequencing logic.

3.0 PEACH BOTTOM EPS DESCRIPTION

The Peach Bottom EPS provides reactor protection power for safe shutdown and ESF power to mitigate the effects of transients and accidents. In contrast, the BOP system provides power to those loads which, nominally, have no safety implications but which are required for continuous plant operation and for general purposes.

The major constituents of the total electrical power distribution system are shown in Figure B2-2, and a more detailed version is shown in Figures B2-3 and B2-4. The Unit 3 main generator is included in both figures to show its relationship with the emergency power system of Unit 2. However, except for the following components which are common to both units, the emergency power system for Unit 3 has been omitted because it has no effect on the emergency power system of Unit 2:

a. The diesel generators;

b. The emergency cooling tower load centers;

c. The Unit 3 DC system (some of the Unit 2 DC emergency loads are fed from the Unit 3 DC system).

During normal operation the Unit 2 main generator provides power to the 500 KV South Substation through the main transformer which raises the generated voltage from 22 to 500 KV. The Unit 2 main

generator also provides power to the 13.2 KV BOP system through the unit auxiliary transformer which lowers the generated voltage from 22 to 13.2 KV. In no case does the output of the Unit 2 main generator serve directly the emergency power system. In contrast, under certain conditions as described later, the BOP loads are served from the offsite power sources, the preferred source of power for the emergency power system.

During startup, hot standby, or shutdown operations, both the BOP system and the emergency power system are fed from 230 KV switchyard and/or the 500 KV switchyard. The common feeds during these modes of operation follow. If the 230 KV system supplies all the power, startup transformer 00X03 lowers the voltage from 230 to 13.2 KV and feeds startup transformer switchgear 00A03. This switchgear in turn distributes power to the BOP system via two separate circuits and to the emergency power system via a third circuit. If the 500 KV system supplies all the power, the tertiary windings on the 500/230/13.8 KV auto-transformer at the North Substation feeds the 13.8/13.8 KV startup and regulating transformer 00X05. This transformer serves directly startup-regulating transformer switchgear 00A04, from where BOP power is obtained via two separate circuits, and emergency power via a third circuit. If both the 230 and 500 KV systems provide the power, the feeds are essentially as described above, except that each provides power for one-half the BOP and emergency power systems.

Offsite power for the emergency power system is distributed via two startup buses (00A03A and 00A04). These buses in turn provide power to two 4 KV buses (00A19) and (00A20) via two emergency auxiliary

transformers (0AX04 and BX04) which lower the voltage from 13.2 to 4.16 KV. Each of these buses (00A19 and 00A20) in turn feed two of the four emergency auxiliary switchgear buses (20A15, 20A16, 20A17 and 20A18). Under normal conditions, the emergency power system is served from two offsite sources, each capable of supplying the total emergency requirements of both units.

In the event of a LOCA, the sequences that follow would normally occur. The turbine-generator would trip, and 500 KV breakers 215 and 225 would open. In addition, breakers 0101 and 0214 (on 13.2 KV buses 20A01 and 20A02) would open, thereby causing the loss of all BOP loads; however, upon such loss these loads would be automatically transferred to the offsite power system as described for the shutdown case. The LOCA would generate an ESF signal which would activate the ESF systems. Normally, the ESF systems would be powered from the offiste sources. The ESF signal would also start the diesel generators, and if offsite power is lost the diesel generators would serve the ESF loads. If offsite power is lost coincident with, or during the course of a LOCA, power will not be available for the BOP loads.

Two offsite power sources are provided, each capable of serving all the emergency power requirements of both units. One originates at the 230 KV substation that serves the Nottingham-Graceton transmission lines and interfaces with the emergency power distribution system at 4.16 KV bus 00A19. The other originates at the 500 KV North Substation and interfaces with the emergency power distribution system at 4.16 KV bus 00A20. Under normal conditions, each offsite source serves half the emergency power system requirements and acts as an alternate source of offsite power for the other. These two

sources are normally aligned to serve two divisions of the emergency power distribution system (Division I and Division II). The major components of the offsite power system are aligned to these divisions as follows:

Division I

230 KV Bus (Nottingham-Graceton Trans. Lines)

Startup Transformer 00X03

Startup Transformer Switchgear 00A03

Emer. Aux. Transformer 0AX04

4.16 KV Bus 00A19

Division II

500 KV North Substation (500/230/13.8 Auto-transformer)

Startup Transformer 00X05

Startup Transformer Switchgear 00A04

Emergency Aux. Transformer

4.16 KV Bus 00A20

The onsite AC power system consists of four diesel generator sets, 0AG12, 0BG12, 0CG12 and 0DG12, and auxiliaries required to start each diesel and to connect each generator to its bus. Each diesel is rated 3100 KW, and is capable of assuming full load within thirteen seconds of loss of offsite power. Each diesel generator is aligned to serve a specific 4.16 KV bus on Unit 2 and a companion bus on Unit 3.

Each diesel generator can be started manually (locally or at the control room) or automatically. The manual starts are usually for test purposes only. In contrast, the automatic starts represent an emergency condition, i.e., either a LOCA-related signal or low voltage on the 4.16 KV emergency buses.

Fuel oil is supplied directly to each diesel engine from a 550 gallon day tank. The day tank permits full load operation for approximately three hours. Makeup fuel is automatically transferred to the day tanks, as required, from four storage tanks via separate transfer pumps. The combined fuel oil storage capacity permits full load operation of all the diesels for at least seven days.

Loading of each generator is accomplished through a series of timed circuit breakers. These circuit breakers maintain adequate voltage levels by sequentially starting the ESF loads. The loading sequence during a LOCA and a coincident loss of offsite power requires approximately thirty seconds after the first load is energized.

Protective devices for the diesel generator sets are of two types: 1) those related to mechanical troubles, 2) those related to electrical problems. Most protective devices normally associated with impending mechanical failures of the diesel engine are bypassed whenever the diesels are started in an automatic (emergency) mode. Protective devices so bypassed are annunciated in the control room, and include jacket coolant high temperature, jacket coolant low pressure, lube oil high temperature, and lube oil low pressure. The only mechanical protective device that is not bypassed and that will trip a diesel engine is the engine overspeed device. The electrical protective relays that trip the generator circuit breaker are: generator differential overcurrent; 4.16 KV bus differential overcurrent; generator phase overcurrent; generator ground neutral overcurrent; and antimotoring. In addition, other protective relays and devices are provided to annunciate abnormal generator conditions at the control room such as generator field ground current, generator

loss of field, and generator bearing high temperature. Standby and operating data are annunciated or indicated in the control room to provide continuous information regarding the performance of the diesel generator units.

The emergency AC power distribution system consists of four 4160V AC buses: four 480V AC load centers, fourteen 480V motor control centers, and four 120/208V AC panels. These buses are arranged to form four redundant but not completely independent channels; ZA, ZB, ZC and ZD. These four channels are paired to form two redundant and electrically independent divisions, Division I and Division II.

Buses 20A15, 20A16, 20A17 and 20A18 (4160 volt) are the sources of AC power to channels ZA, ZB, ZC and ZD, respectively. If one of these buses is lost, all AC power to its associated channel is also lost. Because of the importance of continuity of services to these buses, each is provided with three sources of power: two from the offsite power source, of which one is the normal source and the other is the alternate source which assumes the load if the former fails; and an onsite source which assumes the load if both offsite sources fail. In other words, if the normal offsite source fails, the affected bus is automatically transferred to the alternate offsite source, and if both offsite sources fail, the onsite source (the diesel generator) automatically provides power to the bus within thirteen seconds of loss of offsite power. Each 4160 volt bus is rated at 1200 amperes continuous and serves directly the ESF motors that are rated at 250HP and above and distributes AC power to the lower rated ESF loads via a distribution transformer and a 480 volt load center. Control power for the circuit breakers is obtained from 125 volt DC panels.

The 480 volt load center buses are energized from 4160 volt buses via 4160/480 volt load center transformers, respectively. These buses are the main sources of power for the 480 volt channels. Thus, if any 480 volt load center is lost, all 480 volt power to its associated channel is also lost. Each bus is equipped with a 480/120 volt control transformer which feeds an integral 120 volt control bus for each load center. These buses do not serve any ESF motors directly, but they do serve the 480 volt motor control centers which serve the ESF motors rated below 250 HP.

The emergency power distribution system includes fourteen motor control centers which are energized by the 480 volt load centers as indicated above. The motor control centers serve directly the ESF motors that are much smaller than those served by the 4160 volt buses, including auxiliary components associated with the larger loads served that may cause a runaway condition. In addition, the diesel engine system is provided with detectors which indicate abnormal conditions such as low lube oil pressure, low coolant water pressure, high coolant water pressure, and high lube oil temperature. Ground detection devices are also provided for the DC system; however, since the first ground does not affect the operability of the DC system, a ground alarm only is actuated.

The trip settings of the relays are coordinated to minimize the effects of any failure on the overall emergency power system. The relays are set so that the breaker that feeds a faulted circuit would be the first to trip, thereby confining the loss of power to the affected feeder. Indicating devices such as indicating lights, alarms, and annunciators are also provided. Thus, if the automatic

protective device should fail, the operator may be able to take appropriate action by using the manual control devices located in the control room or at the breaker panels.

4.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM EPS

The major Grand Gulf and Peach Bottom Design characteristics are summarized below for comparison:

Grand Gulf EPS	Peach Bottom EPS
. three diesel generators/unit	. two diesel generators/unit
- no inter-unit bus ties	- with inter-unit bus ties
. load sequencing	. load sequencing
. three load divisions/unit	. two divisions/unit
- one diesel/load division - one division for HPCS - two divisions for remaining redundant ESF	- one diesel/load division (HPCIS is steam driven)
. three independent 125 VDC power supplies/unit	. four 125 VDC supplies serving unit 2 and unit 3
- one supply/load division - one battery/supply - two battery chargers/battery	- one battery/supply - one battery charger/battery - inter-unit bus ties
. three independent 120 VAC channels/unit	. four 120 VAC channels serving unit 2 and unit 3
- no inter-unit bus ties	- inter-unit bus ties

The significant difference between Grand Gulf and Peach Bottom was the dedicated HPCS load division employed by Grand Gulf.

Peach Bottom and Grand Gulf's EPS unavailabilities were both dominated by the diesel generators failing to start when needed. The probability of a total loss of electricity at LOCA for Peach Bottom was calculated in the RSS to be 1.0×10^{-6}/reactor year. A similar calculation for total loss of electric power for Grand Gulf yields

2.5×10^{-7}, which includes failure of all three EPS divisions given LOP at the beginning of a LOCA.

5.0 GRAND GULF MODEL DESCRIPTION

5.1 Event Tree Interrelationships

The principal function of the emergency power system is to provide ESF system power to mitigate the effects of transients and LOCAs when offsite power is not available.

The Grand Gulf EPS was not modelled as a single event tree event since it was explicitly included in the Boolean models developed for each power dependent system. Failure of an EPS division is defined as failure of the associated diesel to provide power when offsite power is lost. Loss of offsite power is the initiating event for the T_1 accident sequences. Offsite power can also be lost during a LOCA since the power grid might become unstable after load rejection. Offsite power is assumed available during T_{23} accident sequences. Nonrecovery of offsite power is incorporated into T_1 sequences with the Boolean terms LOPNRE (nonrecovery in 30 minutes) and LOPNRL (nonrecovery within about 30 hours given LOPNRE).

5.2 Grand Gulf EPS Model Description

5.2.1 EPS Boolean Equations

Three Boolean equations were developed for the EPS; one for each A.C. division (I, II, or III). These equations are:

$$EPS1 = BATA + SSWA + DIESEL1 + V1 \quad ,$$

$$EPS2 = BATB + SSWB + DIESEL2 + V2 \quad ,$$

and

$$EPS3 = BATC + SSWC + DIESEL3 + V3 \quad .$$

Table B2-1 lists definitions of each term in the previous equations. Refer to Figure B2-1 for a simplified diagram of Grand Gulf's EPS.

Table B2-2 lists fault identifiers that label specific failures that contribute to the system unavailability.

Inspection and testing of the 500 KV, 115 KV, and 34.5 KV breakers, disconnects, and the transmission line protective relaying are done on a routine basis, without removing the service and ESF transformers from service. Routine maintenance on power circuit breakers is performed to verify that all design criteria for operation are not exceeded. Calibration checks of the protective relaying in the switchyard will be performed on a routine interval of not more than 2 years.

Periodic testing will be performed on the onsite power system from the sensing elements through the driven equipment to assure that the equipment is functioning in accordance with design requirements. The drawout feature of protective relays permits replacement relays to be installed while the relay that was removed is bench tested and calibrated. Startup of the diesel generator is accomplished by simulation of a LOCA or loss of preferred power. A key-locked mode switch permits testing only a single generator set at a time.

The maintenance contribution to EPS division unavailability is from the diesel generator and standby service water motor-operated valves on the inlet to the diesel jacket water coolers serving EPS divisions 1 and 2. Typical mean outage time for MOVs is 19 hours, 21 hours for diesels. The average maintenance interval used in the Reactor Safety Study is 4.5 months, which corresponds to a frequency of .22 acts per month. Therefore:

$$Q_{mov\ maintenance} = \frac{19}{720} \times .22 = 5.8 \times 10^{-3}$$

and

$$Q_{diesel\ maintenance} = \frac{21}{720} \times .22$$

$$= 6.4 \times 10^{-3}$$

The only human error associated with EPS division failure was the failure to return valves F023A, F023B, F185A, F185B, F186A, or F186B to normal condition (open) after maintenance. Inadvertent closure of these valves will block cooling flow through the diesel generator jacket water coolers. The diesels can run only three minutes without jacket cooling according to the Grand Gulf FSAR, so these valve positioning errors could cause EPS division failure.

For a manual valve that is closed during maintenance, the steady state probability that it will be found closed during a given month (unavailability) is estimated in the RSS by the conditional probability.

Q = p(undetected/left closed) p(left closed/maint.) p(maint.)

where, p(undetected/left closed) = 1/3, is the estimated probability that the valve misalignment is not detected during walk-around plant inspections, p(left closed/maint.) = 10^{-2} is the basic human error of leaving the valve closed, and p(maint.) = 0.22 is the probability that maintenance took place the previous month, given a mean maintenance interval of 4.5 months. Therefore,

$$Q_{MV\ left\ open} = (.33)(.01)(.22) = 7.3 \times 10^{-4} \quad .$$

No common mode failure was attributed to the Grand Gulf EPS. The EPS divisions are separated electrically and physically, thus making negligible any chance of division interaction.

5.2.2 EPS Unavailability

Using the Boolean equations given in the last section and the term unavailabilities given in Table B2-1, an independent EPS point estimate unavailability can be calculated. These are found to be:

$$EPS1 = 6.7 \times 10^{-2}$$

$$EPS2 = 6.7 \times 10^{-2},$$

and

$$EPS3 = 5.5 \times 10^{-2} \quad .$$

In the Grand Gulf sequence analyses the Boolean equations for each EPS division were incorporated into the equations for each system that required A.C. power.

The dominant failure contributors can be easily identified in Table B2-3. It shows that diesel failures make up about 50% of the total point estimate unavailability for an EPS division.

Failures of the Standby Service Water System also contribute significantly in EPS division unavailability. Terms SSWA, SSWB, and SSWC and contribute about 30% to the total loop failures unavailability.

Table B2-1 Boolean Equation Term Definition

Boolean Term	Term Definition	Term Unavailability
DIESEL1	Diesel Generator 1 Fails	3.6×10^{-2}
DIESEL2	Diesel Generator 2 Fails	3.6×10^{-2}
DIESEL3	Diesel Generator 3 Fails	3.6×10^{-2}
**V1	Standby Service Water Valves F018A-A + F023A	8.0×10^{-3}
**V2	Standby Service Water Valves F018B-B + F023B	8.0×10^{-3}
**V3	Standby Service Water Valves F185A + F185B + F186A + F186B	3.3×10^{-3}
*BATA	Battery A Fails on Demand	1×10^{-3}
*BATB	Battery B Fails on Demand	1×10^{-3}
*BATC	Battery C Fails on Demand	1×10^{-3}
**SSWA	Standby Service Water Loop A Fails	2.2×10^{-2}
**SSWB	Standby Service Water Loop B Fails	2.2×10^{-2}
**SSWC	Standby Service Water Loop C Fails	1.5×10^{-2}

*Refer to Appendix B3

**Refer to Appendix B12. EPS contributions to SSWS loop failure have been removed.

Table B2-2. Component Unavailabilities

Component Description	Fault Identifiers	Failure Contributions	Q/Component
Diesel Generator	DIESEL1		
	DIESEL2	Start Failure	3.0×10^{-2}
	DIESEL3	Maintenance	6.4×10^{-3}
		Q Total	3.6×10^{-2}
Motor Operated Valve (Normally Closed)		Control Circuit	3.0×10^{-4}
	F018A-A	Hardware	1.0×10^{-3}
	F018B-B	Plugged	1.0×10^{-4}
		Maintenance	5.8×10^{-3}
		Q Total	7.2×10^{-3}
Manual Valve (Normally Open)	F023A		
	F023B		
	F185A		
	F185B		
	F186A	Operator Error	7.3×10^{-4}
	F186B	Plugged	1.0×10^{-4}
		Q Total	8.3×10^{-4}

Table B2-3 Quantitative Ranking of Boolean Equation Terms

For EPS1,

DIESEL1	=	3.6×10^{-2}
SSWA	=	2.2×10^{-2}
V1	=	8.0×10^{-3}
BATA	=	1.0×10^{-3}
		6.7×10^{-2}

For EPS2,

DIESEL2	=	3.6×10^{-2}
SSWB	=	2.2×10^{-2}
V2	=	8.0×10^{-3}
BATB	=	1.0×10^{-3}
		6.7×10^{-2}

For EPS3,

DIESEL3	=	3.6×10^{-2}
SSWC	=	1.5×10^{-2}
V3	=	3.3×10^{-3}
BATC	=	1.0×10^{-3}
		5.5×10^{-2}

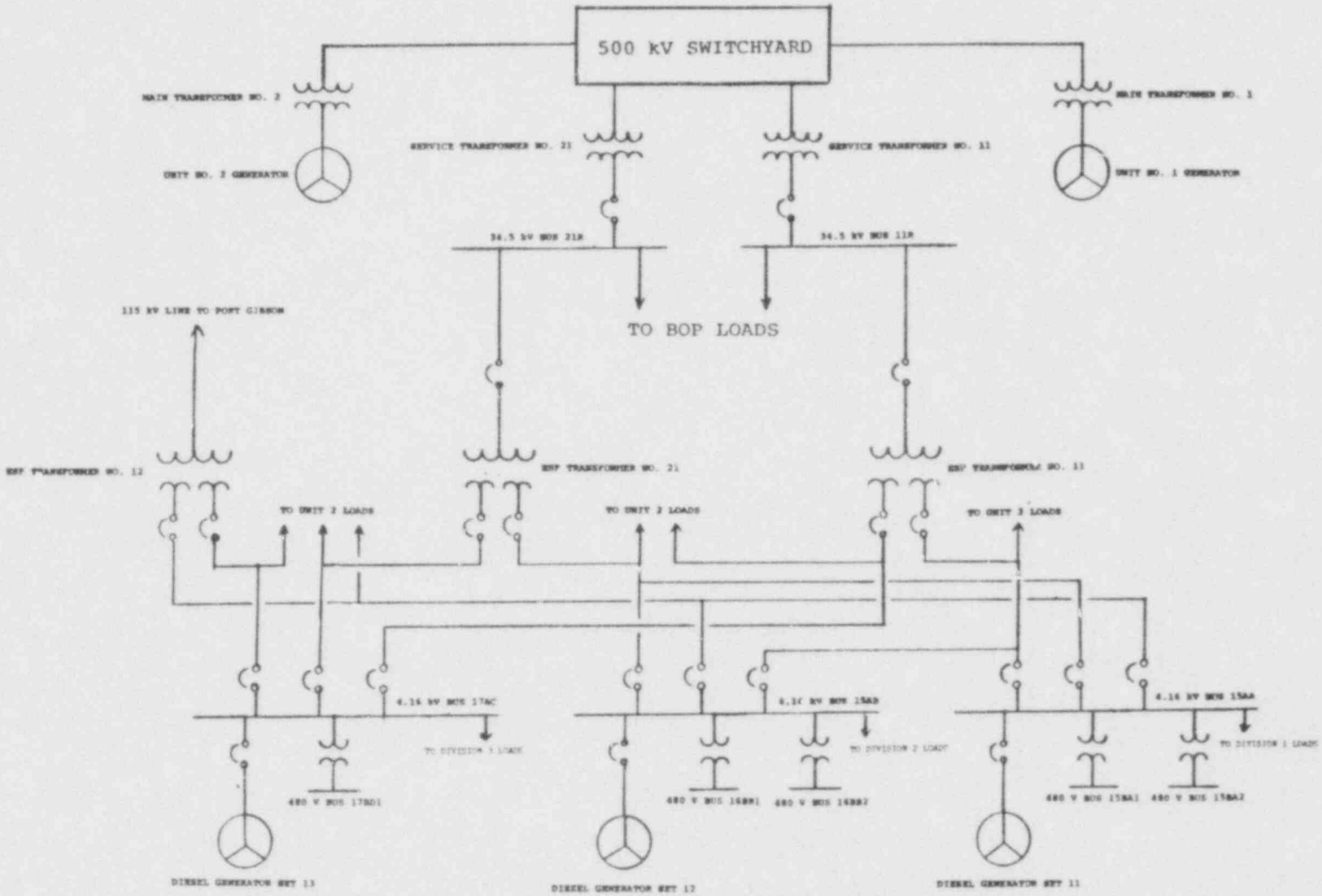

Figure B2-1. Grand Gulf A.C. Power System

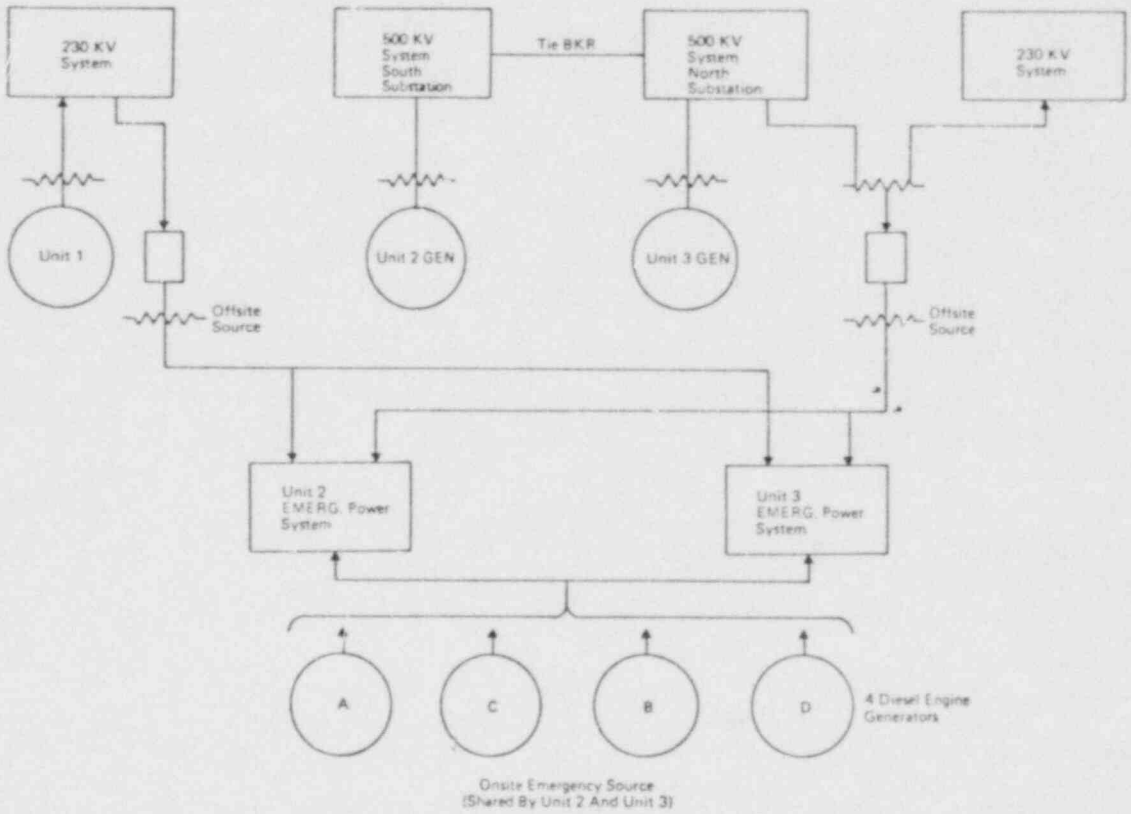

Figure B2-2. Peach Bottom Emergency Power System Simplified Schematic

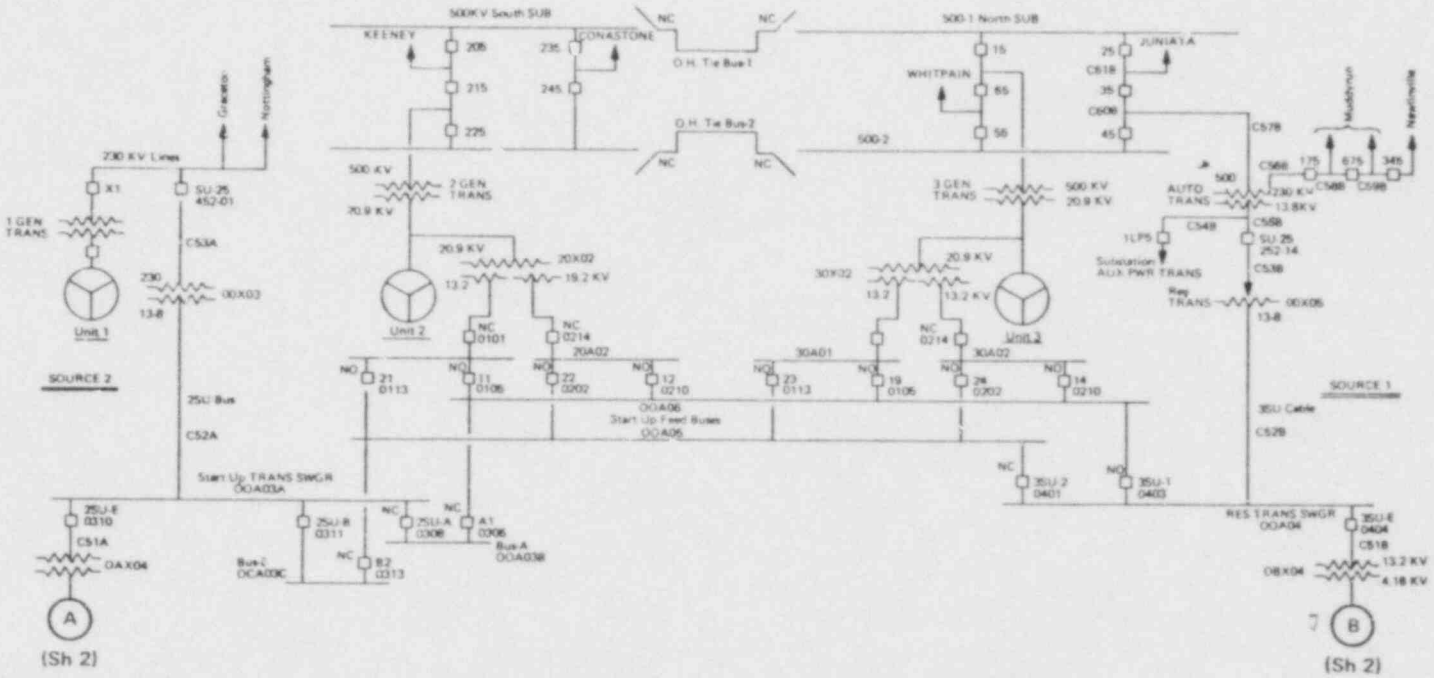

Figure B2-3. Peach Bottom A.C. Power Bus Schematic

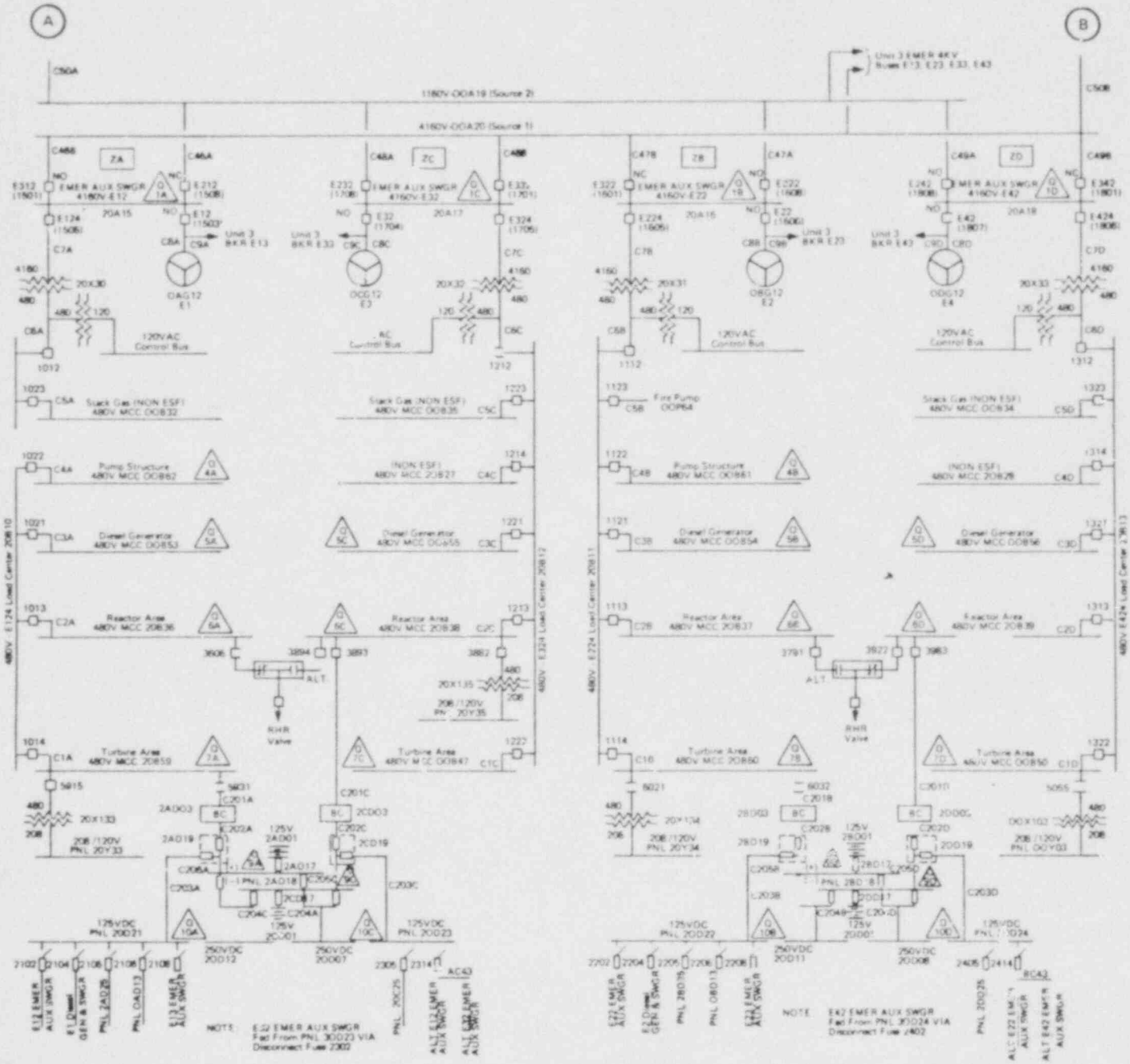

Figure B2-3 (Cont.). Peach Bottom A.C. Power Bus Schematic

APPENDIX B3

SURVEY AND ANALYSIS

DC POWER SYSTEM (DCPS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf DC Power System (DCPS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The DCPS designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report, respectively. A comparison of the two DC power systems is given in Section 4. DCPS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate DCPS failures into the Grand Gulf accident sequences and a point estimate of the DCPS unavailability assuming independence from all other Grand Gulf systems.

2.0 GRAND GULF DCPS DESCRIPTION

2.1 System Description

The Grand Gulf DCPS consists of the following DC power supplies:

a) Station DC Power Supply - Includes three 125 VDC systems for supplying the Engineered Safety Feature (ESF) DC loads and two 125 VDC systems and one 250 VDC system for supplying the balance of plant (BOP) DC loads.

b) Radial Well DC Power Supply - Includes two 125 VDC systems for supplying the radial well DC power requirements.

c) Switchyard DC Power Supply - Includes two 125 VDC systems for supplying the switchyard relay and control systems and two 48 VDC systems for supplying the power line carrier and communications facilities.

d) Turbine Control DC Power Supply - Includes two 24 VDC systems for supplying the main turbine electro-hydraulic control system.

The station DC power supply consists of five independent 125 volt and one 250 volt DC system. Three of the 125 VDC systems, designated as A, B and C, supply DC power to the ESF load divisions. The remaining two 125 VDC systems and the 250 VDC systems, designated as D, E and F, supply DC power to the BOP systems.

Each of the 125 VDC systems (A, B, C, D and E) has a 125 volt battery, two (redundant) battery chargers, and a distribution panel. The BOP 125 VDC systems D and E are connected together in series to form the 250 VDC system. DC systems A and B supply the ESF buses for load divisions I and II and DC system C supplies load division III (HPCS). The schematic diagram for the ESF DC systems A, B and C is shown in Figure B3-1.

The ESF batteries A and B are each rated at 2030 ampere-hours at an 8 hour rate or 2160 amperes for 1 minute. ESF battery C is rated at 100 ampere-hours at an 8 hour rate or 150 amperes for 1 minute. BOP batteries D and E are rated at 2175 ampere-hours at an 8 hour rate or 2400 amperes for 1 minute.

Battery 1A3 feeds into a direct-current load center designated as 11DA. Two battery chargers, 1A4 and 1A5, are fed from the 480 volt engineered safety features load center buses, 15BA1 and 15BA2, which are supplied by a diesel generator if the offsite power source is unavailable. The 125 volt DC system A is formed at the bus of load center 11DA, and the power is fed into a distribution panel to serve various loads. System B is similar to system A, with the load center designated as 11DB, battery 1B3, battery charger 1B4 and 1B5, and 480 volt load centers 16BB1 and 16BB2.

The 125 volt DC system C bus, 11DC, is in a distribution panel, with a battery, two battery chargers, and the loads connected to the bus through molded case circuit breakers. One battery charger gets its supply from the 480 volt ESF MCC 17BD1 and the other charger is fed from a BOP MCC.

The radial well DC power supply, designated as system G, consists of two independent 125 volt batteries each served by two (redundant) battery chargers and is shared by units 1 and 2. Each battery is rated at 100 ampere hours for delivering the required DC power to the equipment in the radial well switchgear house.

The switchyard DC power supply includes a 125 VDC system and a 48 VDC system. The 125 VDC system consists of two independent 125 volt batteries, each served by a battery charger, for supplying DC power for the switchyard relay and control systems. The 48 VDC system consists of two independent 48 volt batteries, each served by a battery charger, and supplies DC power for the communications facilities and the power line carrier. Both the 125 VDC system and the 48 VDC system and shared by units 1 and 2.

The turbine control DC power supply includes two 24 VDC systems for supplying DC power for the main turbine electro-hydraulic control system. Each 24 VDC system consists of two 24 volt batteries each served by a battery charger. The turbine control power supply is essential for normal operation of the turbine but performs no safety function. Each 125 VDC ESF bus is monitored in the control room by a voltmeter.

2.2 System Operation

During normal plant operation the DC power requirements for the ESF and BOP systems are supplied by the battery chargers which maintain the batteries at full charge and are fed from associated AC buses; 480 VAC or 120 VAC. In the event of an accident; i.e., loss of preferred AC power (offsite) or LOCA, the non-essential loads are shed and the essential ESF DC loads are supplied by the diesel generators through the battery chargers. If a diesel generator fails, the associated battery will supply all electrical loads required until AC power is restored for the operation of the battery chargers. Upon restoration of AC power (offsite or onsite) the battery chargers automatically resume supplying the required DC power while recharging the batteries.

3.0 PEACH BOTTOM DCPS DESCRIPTION

The onsite DC power system consists of four 125 V lead-calcium batteries and necessary auxiliaries. Each battery contains 58 cells and has a discharge rating of 190 amperes for eight hours to 1.81 volts per cell (approximately 100 volts per battery). Each battery is provided with a charging unit that receives its primary power from a separate 480 volt emergency motor control center. Under normal conditions, these chargers provide all the DC power required by the loads and maintain the batteries in a floating charge state. It is only upon loss of these chargers or high load conditions that the batteries provide significant DC power requirements.

The four batteries are paired and connected in series to provide two separate 250 volt DC sources in addition to the four 125 volt DC such as that required to control the 13.2 kV and 4.16 kV circuit breakers, control relays, annunciators, and power for exit lighting.

The 250 volt sources provide power for the larger DC loads such as pumps and motor operated valves.

The following DC system abnormalities are annunciated in the control room:

a) 125 volt distribution panel undervoltage;

b) 250 volt distribution panel undervoltage;

c) Battery charger undervoltage;

d) System ground faults.

Unit 3 has a duplicate 250/125 volt DC system that provides power for some of the emergency equipment associated with Unit 2 (e.g., DC control power for diesel generators OCG12 and ODG12). Therefore, the 250/125 volt DC system on unit 3 will be required during the course of a LOCA on Unit 2. The schematic of the DCPS and the unit 2 and 3 interconnections are shown in Figures B3-2 and B3-3, respectively.

The 250 VDC emergency power distribution system includes four 250 volt DC panels, 20D07, 20D08, 20D11 and 20D12. However, since the loads served by panels 20D07 and 20D08 are not safety related, they are not discussed further. Each panel (20D11 and 20D12) is served from a separate bus that places two of the four 125 volt batteries in series to obtain the required 250 volts. The loads served from these two panels are DC motors required to drive pumps or valves. Panel 20D11 serves the auxiliary loads associated with HPCI, such as LPCIS pumps and shutdown cooling valves; HPCI inboard and outboard isolation valves, HPCI loop valve; HPCI suppression pool valves; HPCI pump turbine steam isolation valves. Panel 20D12 serves the auxiliary loads associated with the reactor core

isolation cooling system (RCICS), such as RCIC loop isolation valves; RCIC loop valve; RCIC suppression pool isolation valve; RCIC cooling valve; RCIC turbine trip throttle valve.

The 125 VDC emergency power distribution system includes four 125 volt DC panels, 20D21 (ZA), 20D22 (ZB), 20D23 (ZC) and 20D24 (ZD). Each panel is normally energized from the AC system via one of the four battery chargers; however, if AC power is lost, these panels control power for the 4160 volt emergency buses and for the control circuits associated with the HPCIS and LPCIS plus the control power for several relief valves.

4.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM DCPS

The Peach Bottom DCPS employs four independent 125 VDC power supplies for the unit's ESF equipment. Each of these power supplies includes one 125 volt battery and one battery charger. The Grand Gulf DCPS employs three independent 125 VDC power supplies for the ESF equipment for each unit (1 and 2). Each of these power supplies includes one 125 volt battery and two (redundant) battery chargers. One of the Grand Gulf DC power supplies is dedicated to the High Pressure Core Spray system and the other two power supplies are dedicated to the remaining ESF equipment for the unit.

The DC train unavailability for both Grand Gulf and Peach Bottom is dominated by failure of the battery on demand following a loss of offsite power at 1.0×10^{-3}/reactor-year.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

From an accident viewpoint, the most important function of the DCPS is the startup and control of the diesel generators when offsite

power has been lost. The DCPS is also needed for emergency ADS operation and RCIC control. Failure of a DCPS ESF division is defined as failure of the division to startup and control its associated diesel generator or failure to supply DC power to DC dependent systems.

The Grand Gulf DCPS was modelled explicitly into the Boolean equations developed for the Emergency AC Power System (EPS), RCIC system, and the ADS. The DCPS is important in the T_1 and LOCA sequences where loss of offsite power has occurred or can occur.

5.2 DCPS MODEL DESCRIPTION

5.2.1 DCPS Boolean Equations

The only dominant contributor to DCPS division failure was ESF battery failure on demand after a loss of offsite power. No other failures were found to be significant.

The Boolean terms BATA, BATB, and BATC have been used to depict the demand failures of ESF batteries A, B and C, respectively.

Testing and maintenance of the ESF batteries and charges did not contribute to the system unavailability because such acts would either not take the division out of service or would be done during refueling.

5.2.2 DCPS Unavailability

The Reactor Safety Study value of 1×10^{-3} for battery failure on demand was used in this analysis. Therefore,

$$BATA = 1 \times 10^{-3}$$

$$BATB = 1 \times 10^{-3},$$

and

$$BATC = 1 \times 10^{-3} \quad .$$

These are the unavailabilities used in the quantitative analysis for DCPS division power failure and are assumed independent.

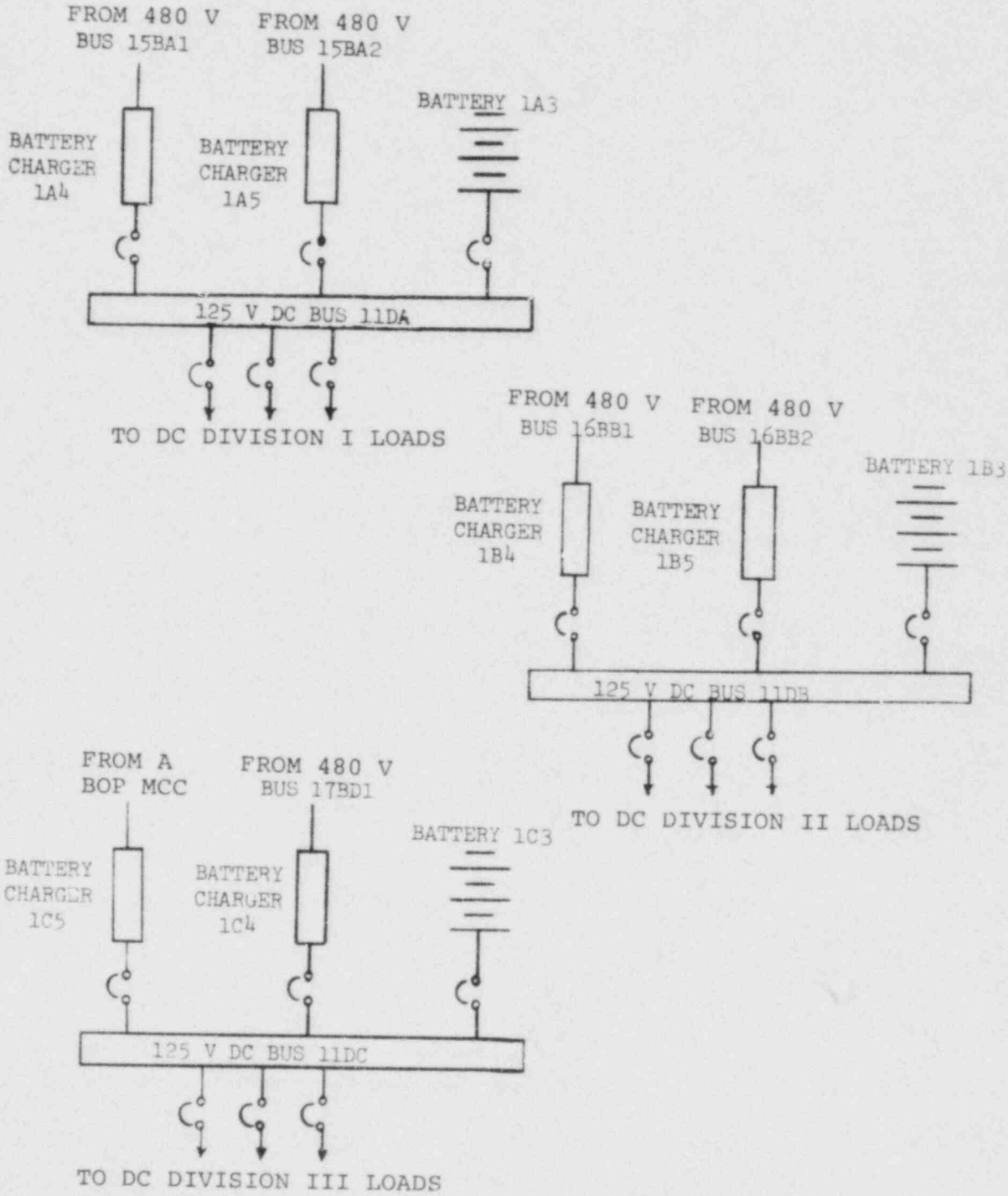

Figure B3-1. Grand Gulf ESF 125 V DC Power System

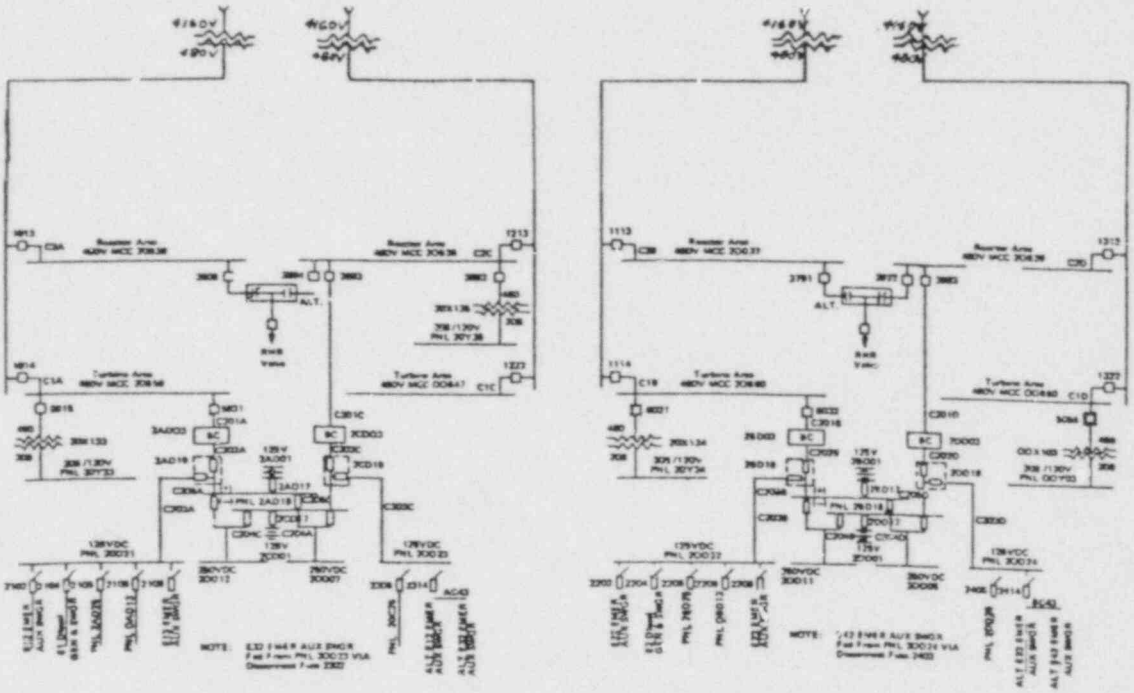

Figure B3-2. Peach Bottom DCPS Schematic

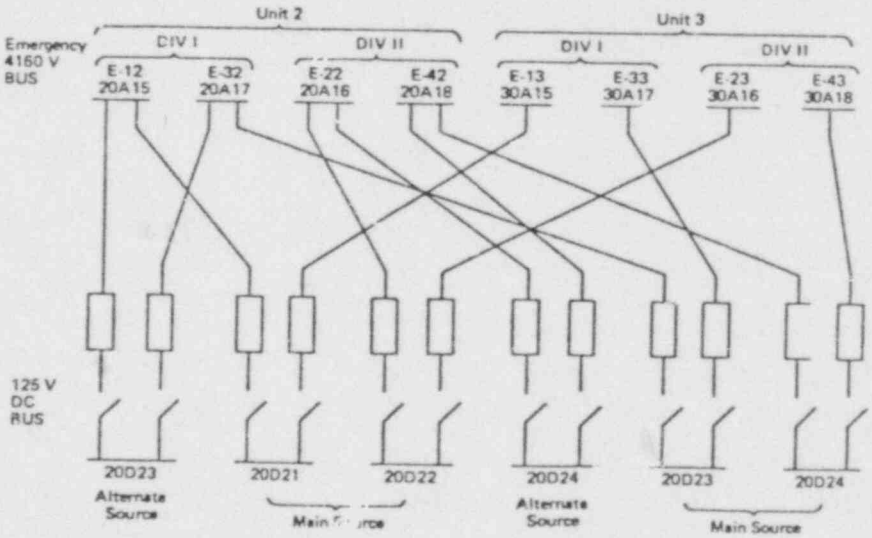

Figure B3-3. Peach Bottom DCPS Interconnections

APPENDIX B4

SURVEY AND ANALYSIS

VAPOR SUPPRESSION SYSTEM (VSS) - GRAND GULF PLANT

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5.2.2	VSS Unavailability	B4-10

1.0 INTRODUCTION

The Grand Gulf Vapor Suppression System (VSS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The VSS designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this appendix, respectively. A comparison of the two vapor suppression systems is given in Section 4. VSS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a determination of the VSS unavailability used in the Grand Gulf sequence analyses.

2.0 GRAND GULF VSS DESCRIPTION

2.1 System Description

The Grand Gulf nuclear station has a Mark III containment design which includes a pressure-suppression feature with a dry containment configuration as shown in Figure B4-1. The VSS consists of a suppression pool, horizontal vents, a vent annulus, and vacuum relief valves.

The suppression pool, which provides a means to condense any steam released in the drywell, is a 360 degree annular pool located between the drywell weir wall and the containment wall in the bottom of the containment. The suppression pool water level is checked visually every 24 hours.

The vents, which conduct the steam from a LOCA into the suppression pool, are 28-inch-diameter horizontal openings in the drywell wall. There are 45 columns of vents equally

spaced around the drywell. Each column has three vents with their centerlines at eleven feet-four inches, seven feet-two inches, and three feet above the bottom of the suppression pool.

Following a LOCA, vacuum relief of the drywell is provided by the drywell purge system and a separate post LOCA vacuum relief line indicated by the post LOCA vacuum relief valves in Figure B4-1. These valves are the only active components in the VSS. There are no automatic or operating bypasses in the drywell purge system.

2.2 System Operation

Steam from a LOCA within the drywell will rapidly pressurize the drywell. This buildup of pressure will force the water down in the vent annulus. When the water is depressed to the top level horizontal vents, the steam will be vented to the suppression pool and condensed. If the drywell pressure is high enough, the middle and bottom level horizontal vents will be uncovered, thereby allowing more steam to be vented to and condensed in the suppression pool.

When the reactor pressure drops to the drywell pressure, the drywell will contain saturated steam. The drywell and containment pressures will stabilize with the pressure difference corresponding to the hydrostatic head between the pool level and the first vent.

The drywell purge system is interlocked with the ECCS to prevent system operation unless a LOCA has occurred. Initiation at the system level is prevented until 30 seconds after a LOCA is detected by a signal from the ECCS control system. An interlock

is also provided to maintain the normal drywell vacuum relief valves closed during a LOCA.

Immediately upon detection of a LOCA, the drywell purge compressors are stopped and the purge inlet and vacuum relief valves are closed, should the system be running for test, to ensure that there is no drywell bypass path. Thirty seconds after receipt of the LOCA signal, the drywell purge system is permitted to start. As steam condenses in the drywell, the drywell/containment differential pressure will drop. When the differential pressure drops to 1 psi, the purge compressors will start and the inlet valves will open. Further steam condensation causes the drywell pressure to drop below containment pressure at which time the vacuum relief valves open. As the vacuum is relieved, the vacuum relief valves close again and the purge compressors pressurize the drywell until noncondensible gases are forced through the horizontal vents in the suppression pool to the containment.

An analysis has been performed in the Grand Gulf FSAR which evaluates the capability of the containment to withstand bypass leakage of steam from the drywell, for small primary system breaks, considering containment sprays and containment heat sinks as a means of mitigating the effects of steam leakage. Steam leakage from the drywell to the outer containment is assumed to be caused by small openings in the drywell penetration sleeves.

The analysis assumed a flow rate of one containment spray loop as 5,650 gpm and assumed it to be initiated no sooner than 10 minutes after the accident. The suppression pool water passes through the RHR heat exchanger and is injected into the upper

containment region. The spray is predicted to rapidly condense the stratified steam and therefore create a homogeneous air-steam mixture in the containment. The results of the analysis indicates that with one spray loop operable, the allowable drywell leakage is that of a 12-inch equivalent diameter hole. A similar analysis concluded that without the mitigating effects of at least one containment spray loop operating the allowable drywell leakage would be that from a 3-inch equivalent diameter hole.

3.0 PEACH BOTTOM VSS DESCRIPTION

The Peach Bottom VSS consists of a torus shaped wetwell (suppression pool), vent pipes, a ring manifold, downcomer pipes, and vacuum breaker valves; the components are arranged as shown in Figure B4-2. The function of the VSS is to limit the pressure transient in the drywell resulting from a break in the RCS. This function is successful when the LOCA steam is successfully ducted into and condensed by the wetwell water, thus, maintaining the containment pressure below the maximum tolerable pressure.

The torus shaped wetwell is approximately half filled with water. Eight vent pipes (each 6' 9" diameter), equally spaced about the lower drywell region, connect the drywell to the wetwell. A ring manifold (4' 9" diameter), mounted approximately coaxially within the wetwell, uniformally distributes about the wetwell any steam and any water spilled into the drywell. Connected to the bottom and equally spaced around the ring manifold are 96 downcomer pipes (24" diameter), which direct the steam 4 feet below the water surface. The vacuum breaker valves are large check valves that allow air flow from the wetwell airspace to

the drywell, but not from the drywell to the wetwell airspace. The status of each vacuum breaker is indicated by lights on a test panel in the reactor building.

Steam resulting from a LOCA is released into the drywell. The increased drywell pressure forces a mixture of drywell atmosphere, steam and water through the vents into the ring manifold. The mixture will be forced out the downcomers provided that the drywell to wetwell pressure difference is at least two psi. This required difference displaces the four feet of water in the submerged downcomer pipes, thus allowing the steam to condense in the wetwell water and the noncondensibles to collect in the airspace of the wetwell.

Following the LOCA, when the residual drywell steam condenses, the drywell tends toward a partial vacuum. To relieve this vacuum and prevent collapse of the drywell walls, the gas in the wetwell airspace "backflows" to the drywell via the vacuum breakers.

4.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM VSS

Both systems are designed to condense steam from a LOCA in order to prevent overpressurizing the containment.

The wetwell in Peach Bottom is a torus, half filled with water, which is separate from the outside containment. Grand Gulf, with a Mark III design, utilizes a wetwell that is open to the containment.

In Peach Bottom, steam is carried to the wetwell by vent pipes, a ring manifold, and downcomer pipes. The Grand Gulf VSS utilizes horizontal vents to pass steam into the wetwell.

Single failures dominate both the large and small LOCA cases of VSS failure at Peach Bottom. For the small LOCA case, a vacuum breaker being partially open is the dominant failure type. For the large LOCA at Peach Bottom, downcomer pipe ruptures dominate the system. The median unavailability for the VSS calculated for Peach Bottom in the RSS is: 4.6×10^{-5} for large LOCAs and 1.6×10^{-3} for small LOCAs.

For Grand Gulf, the dominant VSS failure is a large amount of steam bypassing the suppression pool via leaks in the drywell penetrations. Possible steam bypassing through open vacuum breakers at Grand Gulf are double failures and were found to add negligibly to the system unavailability. VSS unavailability is calculated in Section 5.2.2 to be 8.0×10^{-5} for both large and small LOCAs.

As in Peach Bottom, VSS failures due to insufficient water in the torus (suppression pool) and water temperature too hot at LOCA were found to be negligible at Grand Gulf.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

Event D on the LOCA event tree is defined as failure of the VSS. Vapor Suppression System failure can occur if there is a large steam bypass due to drywell leakage (greater than a 12-inch equivalent diameter) or failure can be due to small steam bypass (3 to 12-inch equivalent diameter) and failure of both containment spray loops. If there is steam bypass of the suppression pool without mitigation the containment will overpressurize and fail.

5.2 VSS Model Description

5.2.1 VSS Boolean Equations

The Boolean equation used to model VSS failure for both large and small LOCAs is:

$$VSS = BLL + BLS*(LPCIA + CSHA)$$
$$*(LPCIB + CSHB).$$

Table B4-1 lists descriptions of each term in this equation. Table B4-2 lists fault identifiers that label specific components in the VSS and failures that contribute to the component unavailability. These unavailabilities include hardware, maintenance, and human faults when applicable.

The terms BLL and BLS represent possible large and small drywell bypass leakage, respectively. No Grand Gulf specific leakage number was calculated. Instead, it was decided that the values calculated for Peach Bottom in the RSS were applicable. The failure probabilities arise primarily from many single passive faults such as ruptures in piping, valves, and penetration welds, etc.

The terms LPCIA, LPCIB, CSHA, and CSHB represent failure of the containment sprays. The containment spray headers tap off the Low Pressure Coolant Injection System (LPCIS) lines between the inboard and outboard isolation valves. Terms LPCIA and LPCIB represent component failures in LPCIS trains A and B. Terms CSHA and CSHB represent component failures in containment spray headers A and B.

Testing of VSS components was found to add negligibly to the component unavailability when compared to other contributions and was therefore not included.

The only maintenance contributions came from maintenance of the containment spray header valves. The average maintenance interval used in the Reactor Safety Study is 4.5 months, which corresponds to a frequency of 0.22 per month. From the Reactor Safety Study, (Table III 5-3) the log normal maintenance act duration for motor operated valves is a mean time of 19 hours. The unavailability of one valve due to mainenance is estimated to be:

$$Q_{MOV\ maintence} = \frac{19\ (.22)}{720} = 5.8 \times 10^{-3}$$

No significant common mode failures were found in the VSS.

5.2.2 VSS Unavailability

Using the Boolean equation given in the last section and the term unavailabilities given in Table B4-1, an independent VSS point estimate unavailability can be calculated. This is found to be:

$$VSS = 8.0 \times 10^{-5}$$

"Double" maintenance contributions which might violate technical specifications were removed from these unavailabilities. For example, unavailability contributions from simultaneous maintenance of both spray valves were removed from the probability calculations.

A quantitative ranking of the Boolean terms of the VSS equation is given in Table B4-3. As can be noted, approximately all of the system unavailability is due to bypass leakage in excess of what the sprays can mitigate (greater than a 12-inch equivalent diameter).

The reader should be cautioned that this is an unavailability for Grand Gulf's VSS if the system is considered independent of all others. In general, the VSS unavailability will depend on what other system successes or failures have occurred; i.e., the unavailability used for the VSS in the sequence calculations is a conditional number.

*Table B4-1. Boolean Equation Term Descriptions

Boolean Term	Term Definition	Term Unavailability
BLL	Drywell Bypass Leakage (> 12 inch equivalent diameter)	8.0×10^{-5}
BLS	Drywell Bypass Leakage (3-12 inch equivalent diameter)	2.1×10^{-5}
CSHA	Containment Spray Valve F028A-A	7.2×10^{-3}
CSHB	Containment Spray Valve F028B-B	7.2×10^{-3}
**LPCIA	Low Pressure Coolant Injection Loop A	2.8×10^{-2}
**LPCIB	Low Pressure Coolant Injection Loop B	2.8×10^{-2}

*Refer to Figure B4-1
**Refer to Appendix B9

Table B4-2. Component Unavailabilities

Component Description	Fault Identifiers	Failure Contributors	Q
Motor Operated Valve (Normally Closed)	F028A-A FO28B-B	Hardware	1×10^{-3}
		Plugged	1×10^{-4}
		Maintenance	5.8×10^{-3}
		Control Circuit	3.0×10^{-4}
		Q Total	7.2×10^{-3}

Table B4-3. Quantitative Ranking of Boolean Terms

BLL	8.0×10^{-5}
BLS*LPCIA*LPCIB	6.3×10^{-8}
BLS*LPCIA*CSHB	1.6×10^{-8}
BLS*LPCIB*CSHA	1.6×10^{-8}
BLS*CSHA*CSHB	4.2×10^{-9}
	8.0×10^{-5}

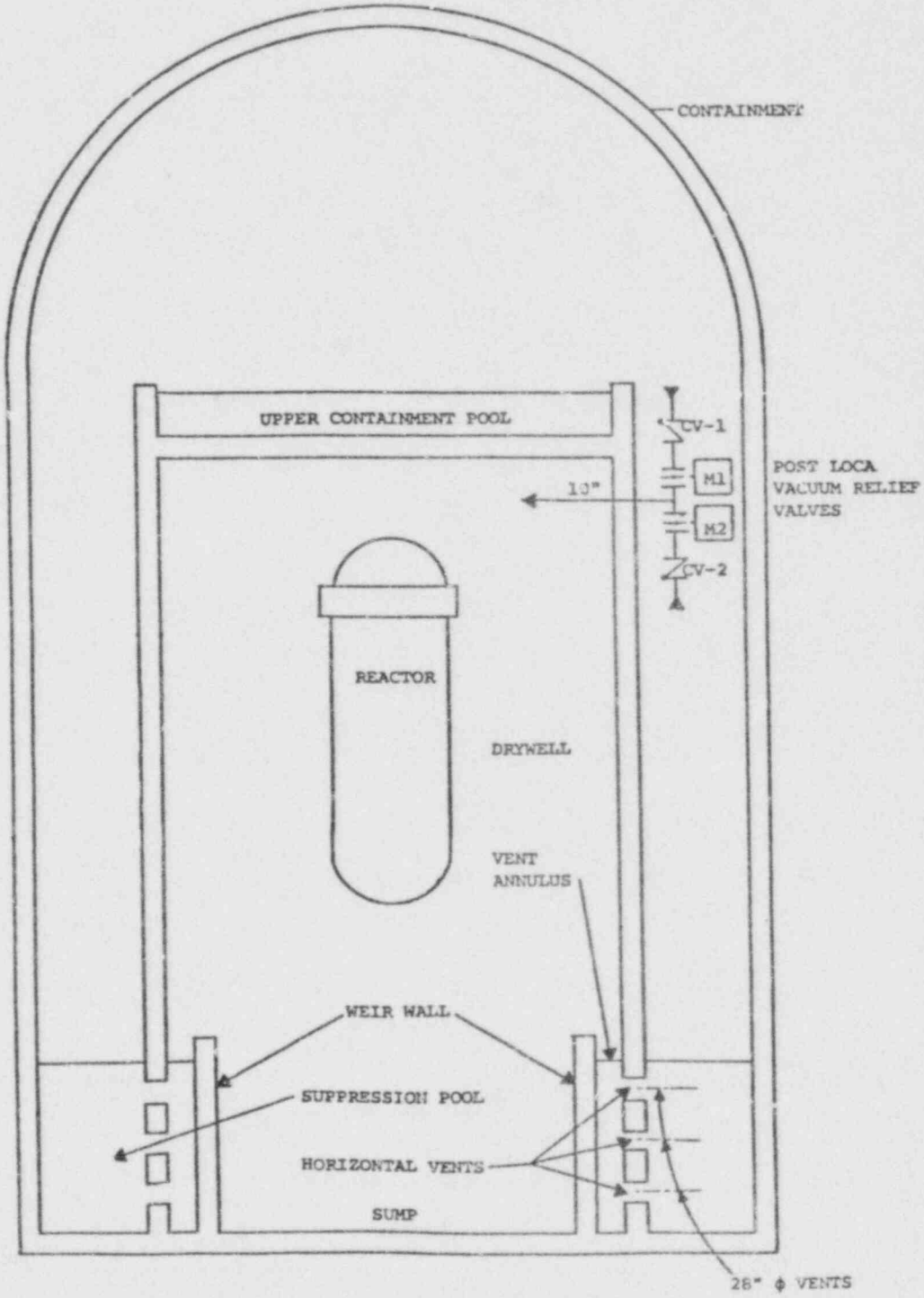

Figure B4-1. Grand Gulf Vapor Suppression System

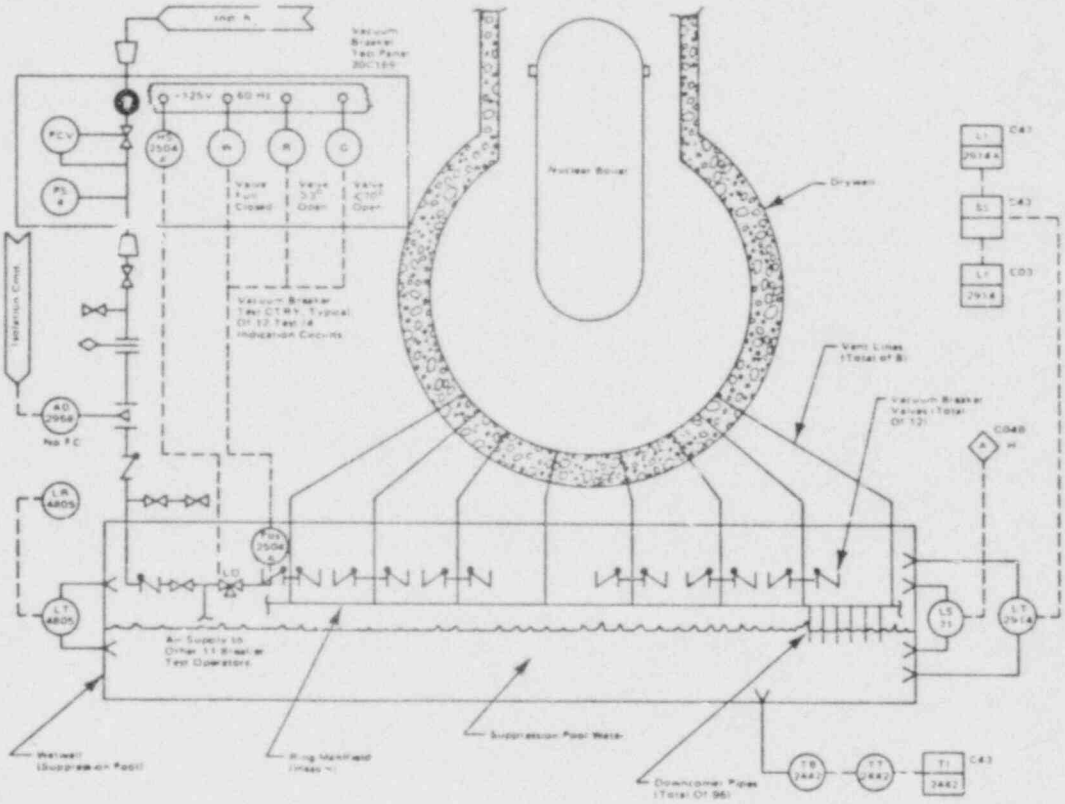

Figure B4-2. Peach Bottom Vapor Suppression System Schematic

APPENDIX B5

SURVEY AND ANALYSIS

HIGH PRESSURE CORE SPRAY (HPCS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf High Pressure Core Spray (HPCS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The HPCS and the High Pressure Coolant Injection System (HPCIS) designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report, respectively. A comparison of the two high pressure systems is given in Section 4. HPCS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate HPCS failures into the Grand Gulf accident sequences and a point estimate of the HPCS unavailability assuming independence from all other Grand Gulf systems.

2.0 GRAND GULF HPCS DESCRIPTION

2.1 System Description

The High Pressure Core Spray system is a subsystem of the ECCS. It delivers water through a spray sparger above the reactor core. The HPCS primary purpose is to provide inventory makeup after small LOCAs which do not depressurize the vessel. However, the HPCS also provides additional cooling for LOCAs of all sizes and transients.

Figure B5-1 illustrates the flow paths and principal components of the HPCS. The pump is a motor-driven centrifugal pump with two suction sources. The condensate storage tank is a source of reactor grade water (170,000 gallons) which is used to fill the reactor vessel in case of coolant loss through a small LOCA. In addition, a pipe is provided from the suppression pool to the

pump suction for use if the condensate supply is depleted. The switchover is automatic. The suction is also automatically transferred to the suppression pool if its level exceeds a preset value. The pump discharge is routed to a spray sparger above the core. Two test lines are provided which return water to the pump suction, the suppression pool or condensate tank under system test. A minimum flow line is also available for pump protection. Its operation is automatic and the line closes when full discharge flow is achieved. The only valve which must change state upon system startup is the injection valve, F004-C. A jockey pump is provided to maintain a full fluid volume in the discharge line (not shown in Figure B5-1).

The HPCS has its own dedicated standby diesel generators which provides power to all HPCS components after a loss of offsite power (Refer to Appendix B2).

2.2 System Operation

The HPCS is initiated automatically upon receipt of low vessel level or high drywell pressure signals. Both parameters, the level and the pressure, are monitored by four trip units which are arranged in a one-out-of-two twice configuration as shown in Figure B5-2. The system is also automatically stopped if the vessel level reaches the high level setting, provided the drywell pressure is within normal limits. Upon initiation, the condensate suction valve is signalled to open (although it is normally open). If the condensate level falls below a preselected value, the suppression pool suction valve opens. Testing of the pump flow is possible through two full-flow test lines which

return to the condensate tank and the suppression pool. The circuit logic overrides any test and returns valves to required positions on receipt of a LOCA signal. The HPCS logic circuit is not shared with any other system.

3.0 PEACH BOTTOM HPCIS DESCRIPTION

The High Pressure Coolant Injection System at Peach Bottom performs the same functions as the HPCS at Grand Gulf. It consists of a steam turbine which drives a booster pump in series with a constant flow coolant pump. These pumps may draw suction from the condensate storage tank or the suppression pool (see Figure B5-3). The turbine is driven by steam, which is generated by residual heat and extracted from the main steam header. In this system, water is injected into the core through the feedwater lines, rather than in a separate sparger as in the Grand Gulf system. Water is first taken from the condensate storage tank and then the suction is switched automatically to the suppression pool when the tank level reaches a preset value. Suppression pool suction is also automatically initiated if the pool reaches a high level. HPCIS initiation is accomplished automatically on receipt of low water level or high drywell pressure signals. The turbine has a control governor which maintains constant flow over the entire operating range. Exhaust steam from the HPCIS turbine is discharged to the suppression pool. In addition to automatic initiation, the HPCIS also automatically stops when the water in the vessel reaches a high level.

The HPCIS is just one part of the Emergency Core Cooling System. The HPCIS is designed for small LOCAs, but these accidents

may also be mitigated by the low pressure systems of the ECCS, provided the ADS reduces the vessel pressure.

4.0 COMPARISON OF GRAND GULF HPCS AND PEACH BOTTOM HPCIS

Although designed to perform the same functions, the Grand Gulf HPCS and Peach Bottom HPCIS have significant differences. The Peach Bottom high pressure system is driven by a steam turbine while the Grand Gulf HPCS employs a motor driven pump. Another major design difference is in the method of delivery to the vessel: the Grand Gulf system uses a spray sparger above the core, while the Peach Bottom delivers through a feedwater line.

In other respects, the systems are very similar. Each has the condensate storage tank or the suppression pool as a suction source. The control systems and initiation are very similar; the differences being due to the steam controls needed for the Peach Bottom HPCIS.

Peach Bottom's HPCIS unavailability is dominated by the estimated downtime for maintenance. The reason for this is the large number of motor operated valves for which maintenance would cause unavailability of the system. Valve maintenance accounts for about half of the total HPCIS unavailability. Maintenance of the turbine driven pump accounts for much of the remainder. The RSS estimated HPCIS unavailability to be 9.8×10^{-2}.

Grand Gulf's HPCS unavailability is also dominated by maintenance contributions of the pump and valves. HPCS unavailability is calculated in Section 5.2.2 to be 2.2×10^{-2} for LOCAs and T_{23} transients and 3.3×10^{-2} for T_1 transients.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

The HPCS is one of four systems which provide emergency coolant injection to prevent core damage for LOCAs and transients. The other three systems are (1) the Low Pressure Core Spray (LPCS), (2) the Low Pressure Core Injection System (LPCI), and (3) the Reactor Core Isolation Cooling System (RCICS).

The failure probability of the HPCS contributes to Event E (ECI) for both large and small LOCAs and Event U (High Pressure ECCS) for transients. In all cases, successful core cooling can be accomplished by HPCS operation alone. Failure of the HPCS is defined as failure of the system to deliver ECCS water to the core at design output.

5.2 GRAND GULF HPCS MODEL DESCRIPTION

5.2.1 HPCS Boolean Equations

Three equations modelling HPCS unavailability were developed: one for LOCAs, one for T_1 sequences, and one for T_{23} sequences. The LOCA HPCS equation differs from the others in that it includes failure caused by loss of emergency power division 3 after a LOCA induced loss of offsite power. The T_1 equation includes the possibility of not recovering offsite power and losing emergency power division 3. In T_{23} sequences, AC power is assumed to be available. These equations are:

$$HPCS\ (LOCAs) = H + LLOP*EPS3 + HACT.$$

$$HPCS\ (T_1) = H + LOPNRE*EPS3 + HACT.$$

and

$$HPCS\ (T_{23}) = H + HACT.$$

Table B5-1 relates each term in the above equations to the components shown in Figure B5-1. Table B5-2 lists total component unavailabilities and each of the contributors to the component unavailability. These unavailabilities include hardware, maintenance, and human faults when applicable.

While testing of the components was found to be insignificant since the control circuit has a test override feature, a test unavailability of 2.3×10^{-4} was estimated for the down time due to logic circuit testing. During this time, the level and pressure trip units are valved out and tested. This unavailability was obtained by assuming a biannual, 1-hour test of HPCS initiating circuits.

The average maintenance interval used in the Reactor Safety Study is 4.5 months, which corresponds to a frequency of .22 per month. The unavailability of a component due to maintenance is estimated to be

$$Q_{maintenance} = \frac{\bar{t}(.22)}{720}$$

where t is the mean maintenance duration. Using a t for pumps and valves of 19 hours we find

$$Q_{pump\ and\ MOV\ maintenance} = 5.8 \times 10^{-3} \quad .$$

The only human error associated with HPCS failure was the failure to return valve F205 to the normal condition after maintenance. Since this valve is normally locked open, an RSS value of 1.0×10^{-4} was attributed to this human error.

5.2.2 HPCS Unavailability

Using the Boolean equations given in the last section and the term unavailabilities given in Table B5-1, independent HPCS point estimate unavailabilities can be calculated. These are found to be

$$\text{HPCS (LOCAs)} = 2.2 \times 10^{-2} \quad ,$$

$$\text{HPCS } (T_1) = 3.3 \times 10^{-2} \quad ,$$

and

$$\text{HPCS } (T_{23}) = 2.2 \times 10^{-2} \quad .$$

A quantitative ranking of the Boolean terms for each equation is given in Table B5-3. It is evident from this table that term H dominates. Term H represents the combined hardware and maintenance unavailability contributions of all HPCS components. Calculations show that component maintenance makes up approximately 40% or more of the total HPCS unavailability.

The reader should be cautioned that these are unavailabilities for Grand Gulf's HPCS if the system is considered independent of all others. In general, HPCS unavailability will depend on what other system successes or failures have occurred; i.e., the unavailabilities used for the HPCS in the sequence analyses must be conditional unavailabilities.

*Table B5-1. Boolean Equation Term Descriptions

Boolean Term	Term Definition	Term Unavailability
H	F205 + F005 + F004-C + F024 + C001-C + F002 + F001-C	2.1×10^{-2}
LLOP	LOCA induced loss of offsite power	1×10^{-3}
**EPS3	Emergency AC Power Division 3	5.5×10^{-2}
LOPNRE	Failure to recover offsite power in 30 minutes	2×10^{-1}
HACT	Failure of HPCS actuating circuit	1.2×10^{-3}

*Refer to Figure B5-1
**Refer to Appendix B2

Table B5-2. Component Unavailabilities

Component Description	Fault Identifiers	Failure Contributors	Q/Component
Check Valve	F005 F024 F002	Hardware	1×10^{-4}
		Q total	1×10^{-4}
Manual Valve (Locked Open)	F205	Operator Error	1×10^{-4}
		Plugged	1×10^{-4}
		Q Total	2×10^{-4}
Pump	C001-C	Hardware	1×10^{-3}
		Control Circuit	1×10^{-3}
		Maintenance	5.8×10^{-3}
		Q Total	7.8×10^{-3}
Motor Operated Valve (Normally Closed)	F004-C	Hardware	1×10^{-3}
		Plugged	1×10^{-4}
		Maintenance	5.8×10^{-3}
		Control Circuit	3×10^{-4}
		Q Total	7.2×10^{-3}
Motor Operated Valve (Normally Open)	F001-C	Plugged	1×10^{-4}
		Maintenance	5.8×10^{-3}
			5.9×10^{-3}
Initiation Logic Circuit	HACT	Fails to Function	1×10^{-3}
		Testing	2.3×10^{-4}
		Q Total	1.2×10^{-3}

Table B5-3. Quantitative Ranking of Boolean Terms

For LOCAs

H	2.1×10^{-2}
HACT	1.2×10^{-3}
LLOP*EPS3	5.5×10^{-5}
	2.2×10^{-2}

For T_1 Transients

H	2.1×10^{-2}
LOPNRE*EPS3	1.1×10^{-2}
HACT	1.2×10^{-3}
	3.3×10^{-2}

For T_{23} Transients

H	2.1×10^{-2}
HACT	1.2×10^{-3}
	2.2×10^{-2}

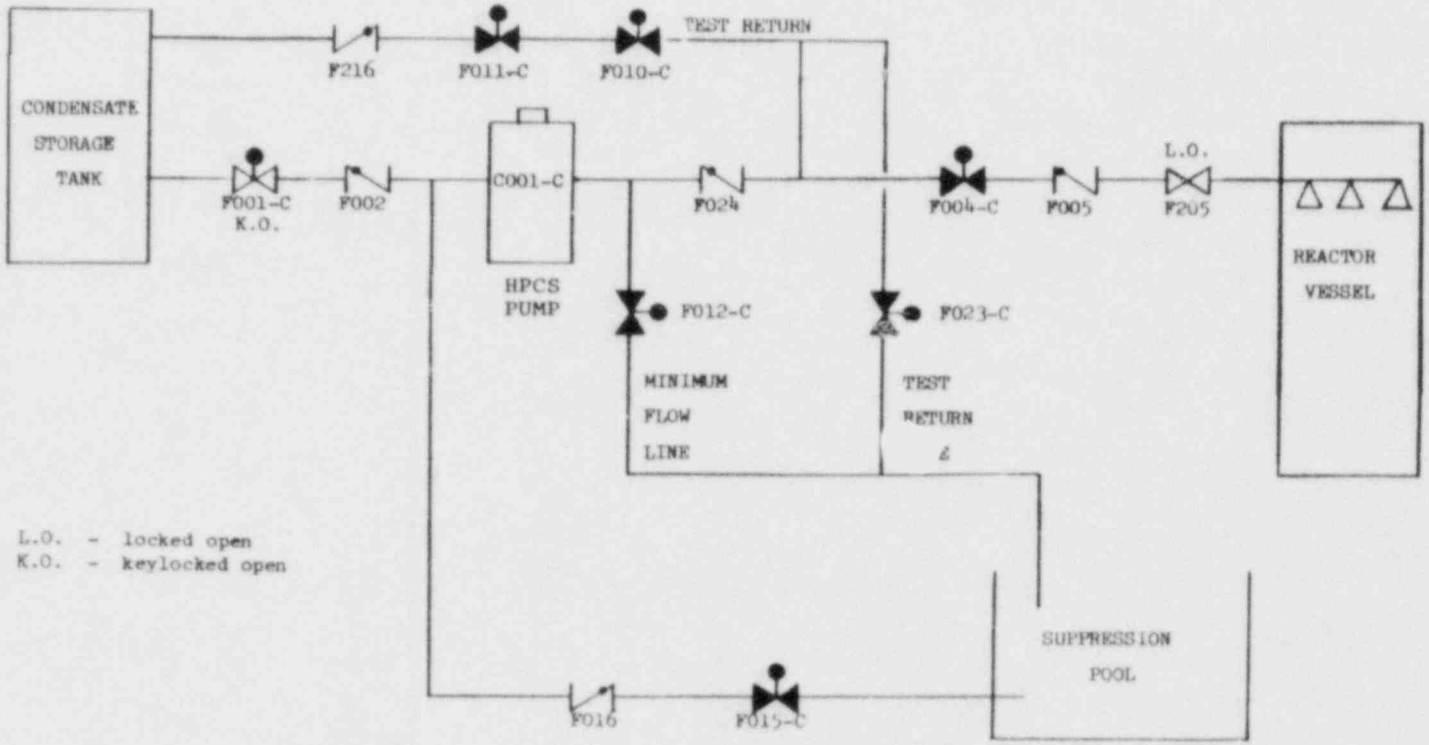
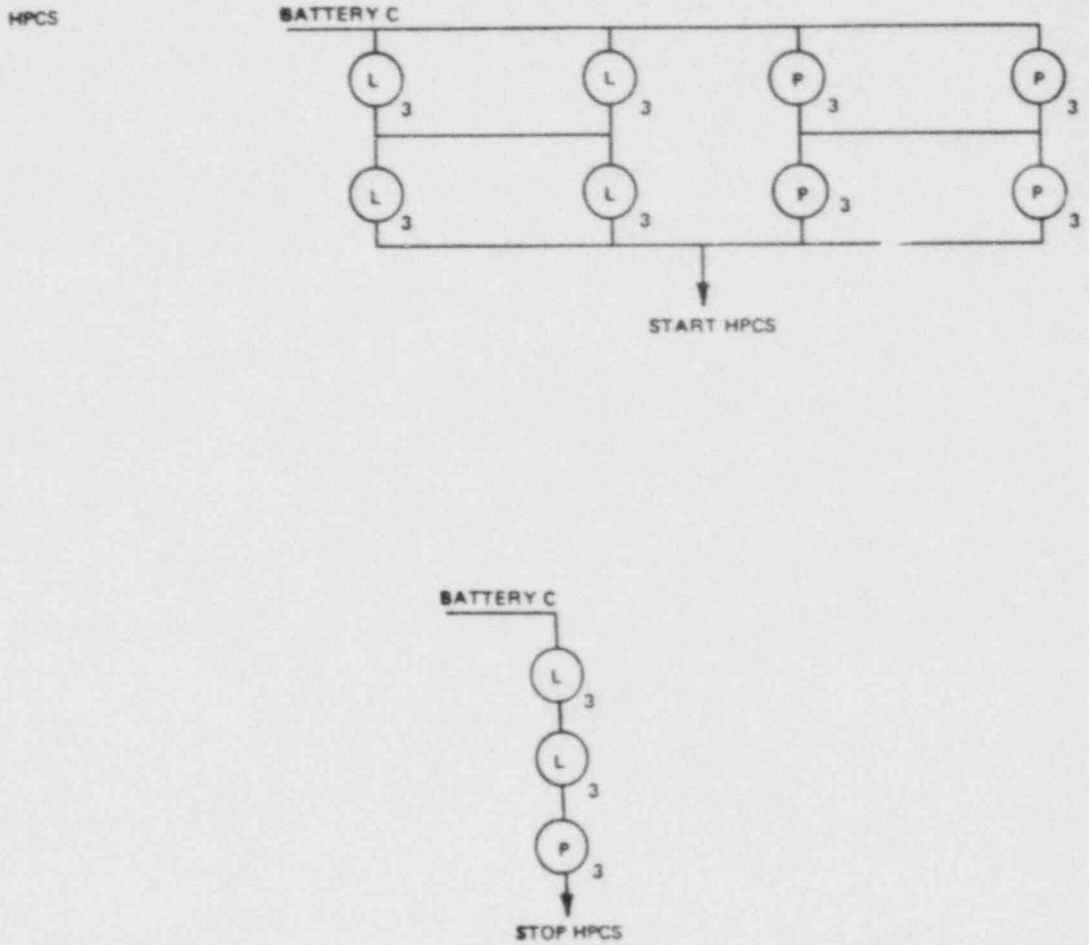


Figure B5-1. Grand Gulf High Pressure Core Spray



(L) - VESSEL WATER LEVEL SENSOR

(P) - HIGH DRYWELL PRESSURE SENSOR

3 INDICATES ELECTRICAL DIVISION 3

Figure B5-2. HPCS Initiating Logic

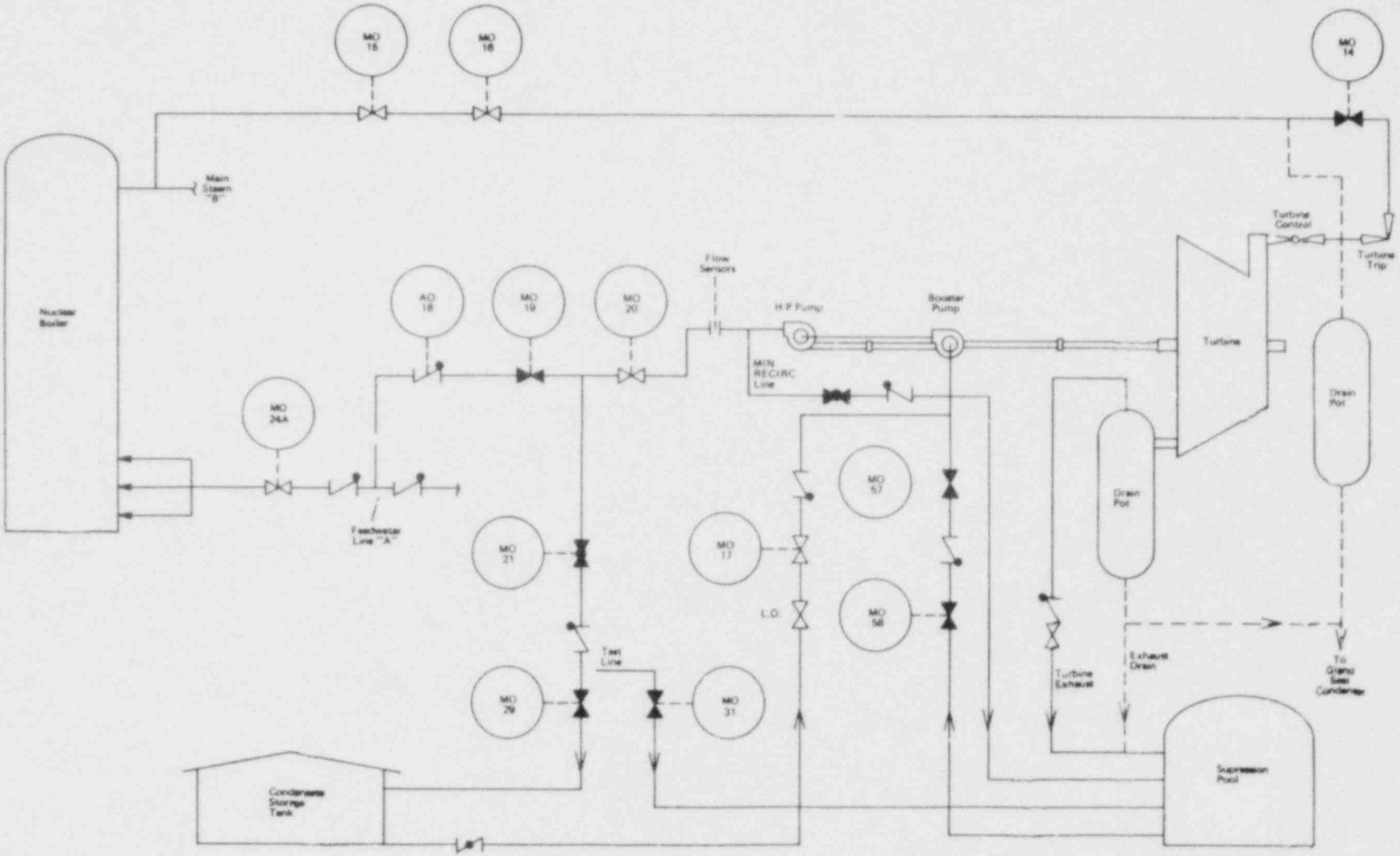


Figure B5-3. Peach Bottom HPCIS Flow Diagram

APPENDIX B6

SURVEY AND ANALYSIS

REACTOR CORE ISOLATION COOLING SYSTEM

(RCICS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf Reactor Core Isolation Cooling System (RCICS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The RCICS designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report, respectively. A comparison of the two cooling systems is given in Section 4. RCICS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate RCICS failures into the Grand Gulf accident sequences and a point estimate of the RCICS unavailability assuming independence from all other Grand Gulf systems.

2.0 GRAND GULF RCICS DESCRIPTION

2.1 System Description

The Reactor Core Isolation Cooling System (RCICS) is designed to provide makeup to the reactor vessel following any conditions in which normal feedwater may be unavailable.

Figures B6-1 and B6-2 illustrate the principal flow paths associated with the Grand Gulf Reactor Core Isolation Cooling System. The primary source of water is reactor grade water from the condensate storage tank. Additional suction sources may be valved in for operation of the RCICS: the suppression pool or the condensate from the RHR heat exchangers when operating in the steam condensing mode. The water is pumped into the reactor vessel through a head spray nozzle.

There is another RHR interface that allows for head spray action with the RHR pumps, but this is not a standard operation and would not be possible at high pressures. As indicated in Figure B6-1, full flow test lines are available which route the water back to the condensate storage tank or the suppression pool.

The steam to drive the turbine is taken from one of the main steam lines. The turbine is regulated by a turbine trip valve and a governor. Two other systems interface with the turbine: the gland seal system, and the lube oil cooling system. The condensate from the RCIC turbine is returned to the suppression pool. All steam lines incorporate drainpots to prevent condensate trapping.

The RCICS is not an engineered safeguard system, however it does act as a redundant system to the HPCS, and is therefore separate from the HPCS physically and electrically. While it is used for a number of shutdown sequences, the principal concern of this analysis is the RCICS ability to provide inventory makeup.

2.2 System Operation

The RCICS is initiated automatically after the receipt of a reactor vessel low water level signal. Four transmitters monitor the reactor water level, each of which is connected to a trip unit. As shown in Figure B6-3, the trip units are arranged in a one-out-of two twice logic. After initiation, design flow rate is produced in 30 seconds. When the vessel level is restored the RCICS automatically shuts down.

A turbine governor limits the turbine speed and adjusts the steam control valve to maintain a constant pump discharge rate.

The turbine is automatically shut down by a trip valve should any malfunction threaten safe operation. In addition, the trip valve is connected to the RCICS logic to provide turbine trip when the reactor vessel level has been restored. The RCICS is interfaced with the RHR system. Working together, the two systems form the steam condensing mode of the RHR system, which utilizes the RHR heat exchangers for condensing the decay heat generated steam. These operations are manually initiated.

The RCIC logic is powered by the 125 V DC division 1 system, except the inboard isolation valve logic which is powered by the 125 V DC division 2 system. Motive power for inboard isolation valves is by division 2 standby AC power, while outboard isolation valves are driven by division 1 standby AC power. The inboard and outboard isolation valves (F064-A and F063-B) are normally keylocked open. The remaining valves are driven by the division 1 DC system. A normally closed DC motor-operated valve is located in the turbine steam supply pipeline just upstream of the turbine stop valve (F045-A). Upon receipt of an RCIC initiation signal, this valve opens and remains open until closed by operator action from the control room.

3.0 PEACH BOTTOM RCICS DESCRIPTION

The Peach Bottom RCICS provides the same functions as the Grand Gulf RCICS. It also acts as a redundant system to the High Pressure Coolant Injection System. The RCICS consists of a steam driven pump with associated piping and controls (see Figure B6-4). Water is drawn from the condensate storage tank or the suppression

pool and delivered to the core via the "B" feedwater line. The system is initiated automatically upon receipt of a low reactor water level signal.

The RCICS is not an engineered safeguard system. Its primary function is to provide a back-up source of water to the core during the initial phase of shutdown cooling. The RCICS may be used following a small LOCA, thus extending the capabilities of the Emergency Coolant Injection System. Failure of the RCICS would not fail the ECI function, as the HPCIS is designed as the primary LOCA response system.

4.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM RCICS

The RCICS of Grand Gulf and Peach Bottom are similar in design and identical in function. The two systems both rely on turbine driven pumps to deliver the water to the core. Aside from physical layouts, the two systems differ in only one aspect: method of delivery to the core. The Grand Gulf system delivers through a spray nozzle above the reactor core, while the Peach Bottom RCICS utilizes one of the feedwater lines. No other major design differences exist. Unavailability of Peach Bottom's RCICS is dominated by estimated down-time for maintenance associated with the large number of motor operated valves. Maintenance of the turbine driven pump also contributes to the RCICS unavailability at Peach Bottom. The median RCICS unavailability calculated in the RSS for Peach Bottom is

$$Q(\text{Peach Bottom RCICS}) = 8.0 \times 10^{-2} \quad .$$

Unavailability of Grand Gulf's RCICS was also dominated by pump and valve maintenance. Grand Gulf's unavailability is

calculated in Section 5.2.2 and is about the same as Peach Bottom's (5.2×10^{-2} for Both T_1 and T_{23} sequences).

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

The RCICS is one of two systems that can provide high pressure emergency coolant injection during transients and small LOCAs. The other system is the High Pressure Core Spray (HPCS). The unavailability of the RCICS contributes to the Event U (High Pressure ECCS) for all transient sequences and to the Event E (Emergency Coolant Injection) for small LOCA sequences. In these sequences, successful RCIC operation will result in successful core cooling. Failure of the RCICS is defined as failure of the system to deliver water to the reactor vessel at design output. Failure of the RCICS does not imply failure of Event U as the HPCS can also provide cooling.

The unavailability of the RCICS also contributes to event W on the transient event tree. The Residual Heat Removal System (RHRS) can operate in two different modes, suppression pool cooling, and steam condensing. In the steam condensing mode, the RHRS takes steam driven by the RCICS and condenses it in the RHR heat exchangers. Therefore, failure of the RCICS will prevent successful RHR steam condensing. Refer to Appendix A.

5.2 RCICS Model Description

5.2.1 RCICS Boolean Equations

Two equations of the RCICS were developed for use in the sequence analysis: one for T_1 transients and one for T_{23} transients

and small LOCAs. The T_1 RCICS equation includes the possibility of not recovering offsite power and then also losing emergency AC power division 1 and emergency DC power division A. In the other equation, it is assumed that offsite power (and therefore DC power) is not lost. These equations are:

$$RCICS(T_1) = R + RACT + LOPNRE*EPS1*BATA \quad .$$

$$RCICS(T_{23} \text{ and "S" LOCAs }) = R + RACT \quad .$$

Table B6-1 relates each term in the above equations to the components shown in Figures B6-1 and B6-2. Table B6-2 lists total component unavailability and each of the contributors to the component unavailability. These unavailabilities include hardware, maintenance, and human faults where applicable.

While testing of RCICS components was found to be insignificant due to a test override capability, a test unavailability of 2.3 x 10^{-4} was estimated for a downtime due to logic circuit testing. This unavailability was obtained by assuming a biannual, 1 hour test of RCICS initiating circuits. During this time the reactor water level trip units are disabled and tested.

The maintenance contribution to the RCICS is from the turbine driven pump and RCIC valves. The average maintenance interval used in the Reactor Safety Study is 4.5 months, which corresponds to a frequency of .22 per month. The unavailability of a component due to maintenance is estimated to be

$$Q_{maintenance} = \frac{\bar{t}\ (.22)}{720} \quad ,$$

where $\overline{t}$ is the mean maintenance duration. Using a $\overline{t}$ of 19 hours (which assumes that components may be out for maintenance for 72 hours) for pumps and valves we find

$$Q_{\text{valve or pump maintenance}} = 5.8 \times 10^{-3}$$

The dominant human error associated with RCICS failure is the inadvertent closure after maintenance of several normally open manual valves. Manual valves F200 and F016 on the RCICS pump line are normally locked open. If either of these valves are closed when the RCICS is needed, the system will fail. An RSS value of 1×10^{-4} was used for this human error. Therefore,

$$Q_{(\text{F200 or F016 Inadvertently Closed})} = 1.0 \times 10^{-4} \quad .$$

5.2.2 RCICS Unavailability

Using the Boolean equations given in the last section and the term unavailabilities given in Table B6-1, an independent RCICS point estimate unavailability can be calculated. These are found to be:

$$\text{RCICS } (T_1) = 5.2 \times 10^{-2}$$

and

$$\text{RCICS } (T_{23}) = 5.2 \times 10^{-2} \quad .$$

A quantitative ranking of the Boolean terms for each equation is given in Table B6-3. It is evident from this table that term R dominates. Term R represents the combined hardware and maintenance unavailability contributions of all RCICS components. Calculations show that component maintenance makes up 50% or more of the total RCICS unavailability.

The reader should be cautioned that these are unavailabilities for Grand Gulf's RCICS if the system is considered independent of all others. In general, RCICS unavailability will depend on what other system successes or failures have occurred, i.e., the unavailabilities used for the RCICS in the sequence analyses must be conditional unavailabilities.

Table B6-1. Boolean Equation Term Descriptions

Boolean Term	Term Definition	Term Unavailability
R[a]	F066 + F065 + F013-A + F204 + F200 + C001 + F016 + F011 + F010-A + F064-A + F063-B + F045-A + TTV + TGV + C002 + F040 + F068-A	5.1×10^{-2}
LOPNRE	Failure to recover offsite power in 30 minutes	2×10^{-1}
EPS1[b]	Emergency AC Power Division 1	6.7×10^{-2}
BATA[c]	Emergency DC Power Division A	1×10^{-3}
RACT	Failure of the RCIC actuating circuit	1.2×10^{-3}

(a) The components composing Boolean term R are depicted in Figures B6-1 and B6-2.

(b) Refer to Appendix B2

(c) Refer to Appendix B3

Table B6-2. Component Unavailabilities

Component Description	Fault Identifiers	Failure Contributors	Q/Component
Check Valve	F066 F065 F204 F011 F040	Hardware	1×10^{-4}
		Q Total	1×10^{-4}
Manual Valve (Normally Locked Open)		Operator Error	1×10^{-4}
	F200 F016	Plugged	1×10^{-4}
		Q Total	2×10^{-4}
Motor Operated Valve (Normally Open)	F068-A F063-B F064-A	Plugged	1×10^{-4}
	F010-A	Maintenance	5.8×10^{-3}
		Q Total	5.9×10^{-3}
Motor Operated Valve (Normally Closed)	F013-A F045-A	Hardware	1×10^{-3}
		Plugged	1×10^{-4}
		Maintenance	5.8×10^{-3}
		Control Circuit	3×10^{-4}
		Q Total	7.2×10^{-3}
Pump		Hardware	1×10^{-3}
		Control Circuit	1×10^{-3}
	C001	Maintenance	5.8×10^{-3}
		Q Total	7.8×10^{-3}
Initiating Logic		Fails to function	1×10^{-3}
	RACT	Testing	2.3×10^{-4}
		Q Total	1.2×10^{-3}
RCIC Turbine	C002	Fails to function	1×10^{-3}
		Q Total	1×10^{-3}
Trip Throttle Valve	TTV	Fails to function	1.3×10^{-3}
		Q Total	1.3×10^{-3}
Turbine Governing Valve	TGV	Fails to function	2.2×10^{-3}
		Q Total	2.2×10^{-3}

Table B6-3. Quantitative Ranking of Boolean Terms

For T_1 Transients

R	5.1×10^{-2}
RACT	1.2×10^{-3}
LOPNRE*EPS1*BATA	1.3×10^{-5}
	5.2×10^{-2}

For T_{23} Transients and "S" LOCAs

R	5.1×10^{-2}
RACT	1.2×10^{-3}
	5.2×10^{-2}

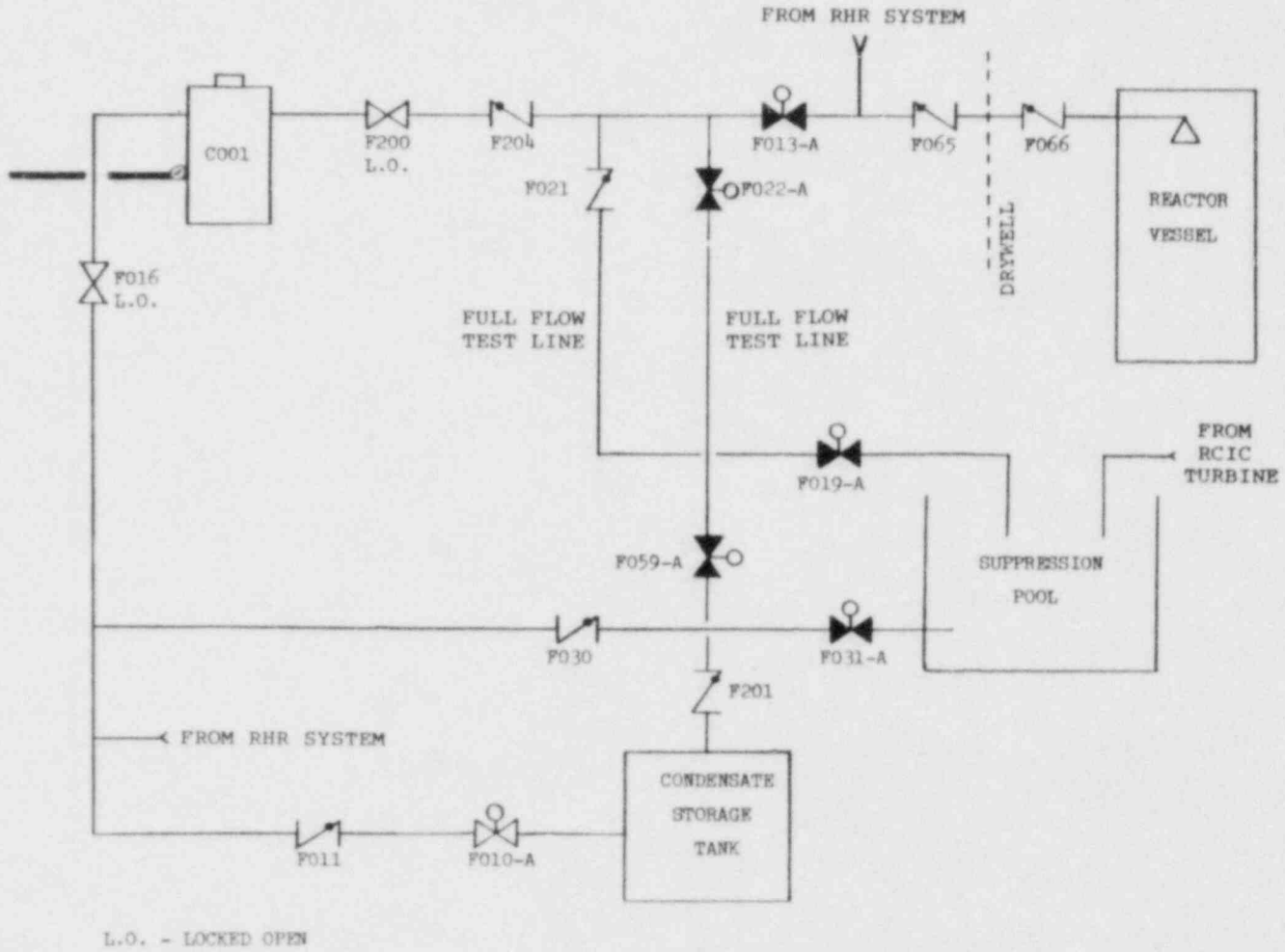
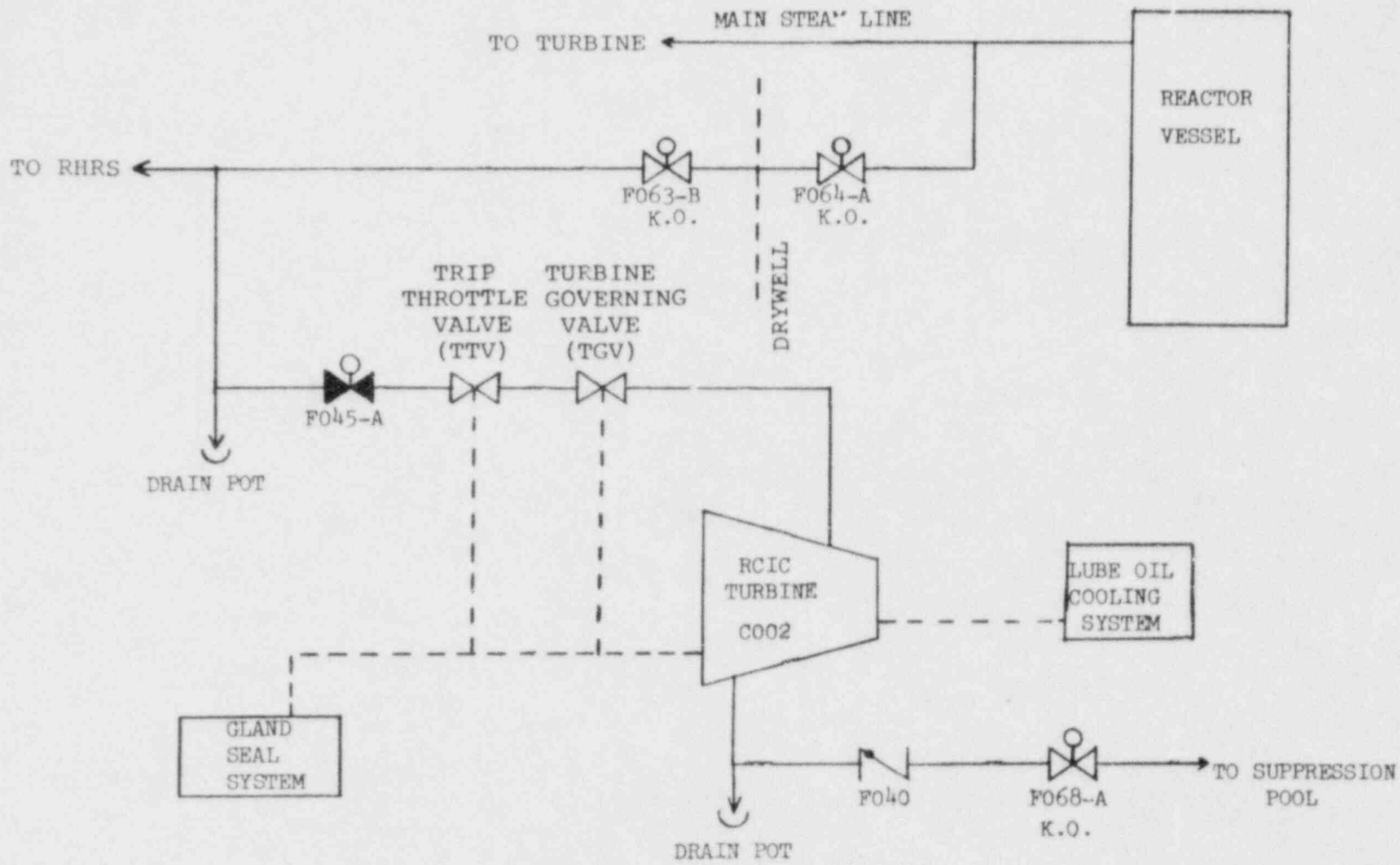
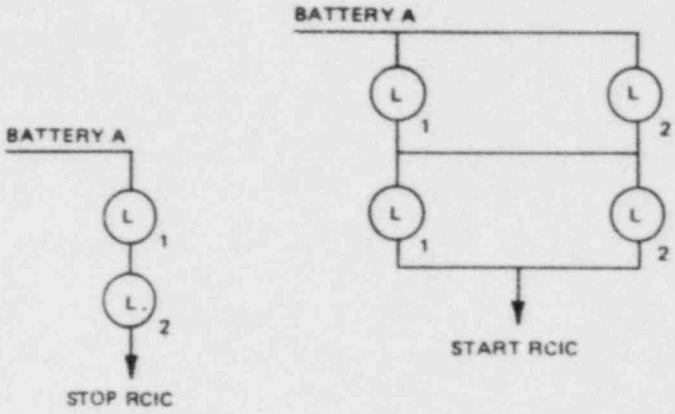


Figure B6-1. Grand Gulf RCIC System (Normal Configuration)



K.O. - KEYLOCKED OPEN

Figure B6-2. Grand Gulf RCIC Turbine Steam Supply



(L) - LOW REACTOR WATER LEVEL SENSOR

1 AND 2 REPRESENT ELECTRICAL DIVISIONS

Figure B6-3. RCICS Initiating Logic

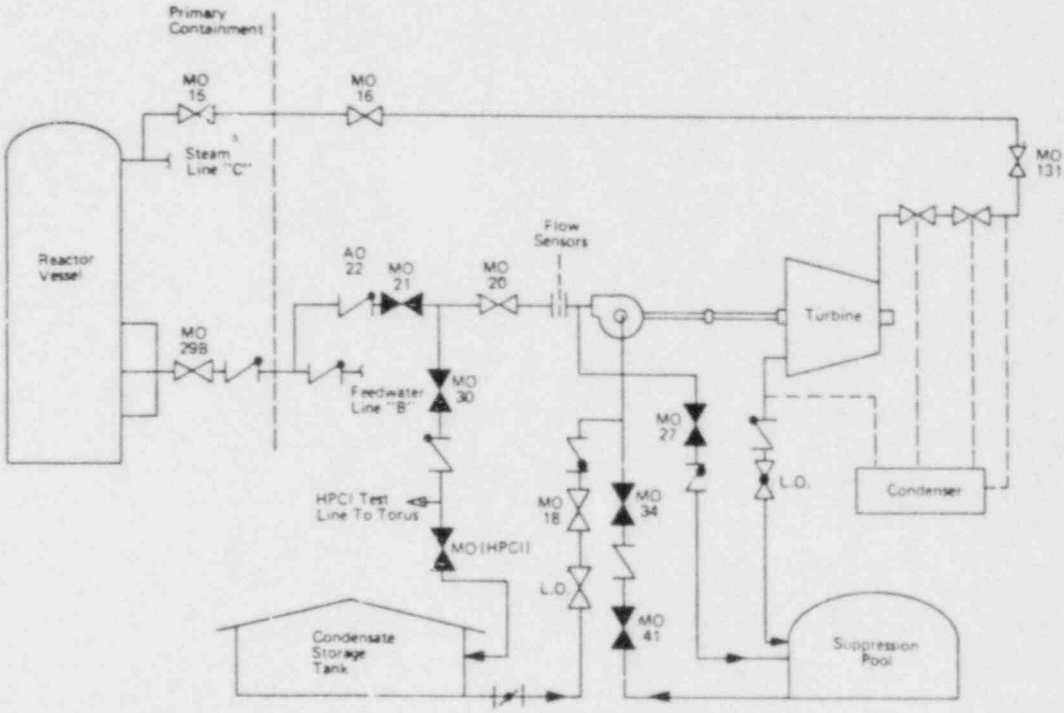


Figure B6-4. Peach Bottom RCICS Simplified Flow Diagram.

APPENDIX B7

SURVEY AND ANALYSIS

LOW PRESSURE CORE SPRAY (LPCS) - GRAND GULF PLANT

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	5.2.2 LPCS Unavailability	B7-9

1.0 INTRODUCTION

The Grand Gulf Low Pressure Core Spray (LPCS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The LPCS and the Core Spray Injection System (CSIS) designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report, respectively. A comparison of the two low pressure systems is given in Section 4. LPCS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate LPCS failures into the Grand Gulf accident sequences and a point estimate of the LPCS unavailability assuming independence from all other Grand Gulf systems.

2.0 GRAND GULF LPCS DESCRIPTION

2.1 System Description

The Low Pressure Core Spray system, depicted in Figure B7-1, is a part of the Emergency Core Cooling System. Its primary purpose is to provide inventory makeup and spray cooling following a large LOCA. When operating in conjunction with the Automatic Depressurization System, the LPCS also provides inventory makeup following small LOCAs and transients.

The LPCS consists of a motor-driven centrifugal pump; a spray sparger in the vessel above the core; piping and valve interconnecting the suppression pool, pump, and sparger; and associated controls and instrumentation. The water is drawn from the suppression pool through a keylocked-open suction (F001-A) valve and delivered to the pump. The flow then proceeds

through a normally closed injection valve (F005-A) and into the reactor spray sparger. The system also has the capability for full flow testing of the pump and suction piping. In this case, the water is returned directly to the suppression pool rather than delivered to the reactor. A minimum flow line is also provided to protect the pump from overheating should valve F005-A be closed. A jockey pump maintains a full fluid volume in the discharge pipe to prevent shock damage upon pump startup. The only valve which must change state upon system startup is the injection valve, F005-A.

2.2 System Operation

The LPCS system is actuated automatically following a LOCA. As shown in Figure B7-2, the initiation signal is derived from two low vessel water level trip units and two high drywell pressure trip units arranged in a one-out-of-two twice network. The initiating signal will be generated if: both level units are tripped, both pressure units are tripped, or either of two combinations of level and pressure units are tripped. No operator action is required. The LOCA signal causes the valve in the test return line (F012-A) to be signaled closed (although it is normally closed), the pump to start, and the injection valve (F005-A) to open when the vessel pressure is in the LPCS operating range. The system may be manually controlled after cancellation of the locked-in signal. The LPCS shares initiating logic with RHR loop A.

3.0 PEACH BOTTOM CSIS DESCRIPTION

The Core Spray Injection System (CSIS) of the Peach Bottom Reactor is comparable to the Grand Gulf LPCS. The Peach Bottom system is a two loop, four pump, redundant system, as illustrated schematically in Figure B7-3 (reference RSS Figure II 6-36). The CSIS provides the same functions as the Grand Gulf LPCS. Each loop consists of two motor-driven centrifugal pumps in parallel which draw from the suppression pool and deliver through a common pipe to a spray header above the core. Each loop is separated mechanically and electrically and the loops are not interconnected. The CSIS is initiated automatically by the LOCA signals of low vessel water level and high drywell pressure.

4.0 COMPARISON OF GRAND GULF LPCS AND PEACH BOTTOM CSIS

The two systems are quite different when viewed without consideration of the other ECCS components. The Grand Gulf system is a single pump, single loop system whereas the Peach Bottom system is redundant, consisting of two independent loops and four pumps. The control and initiation of the two systems is the same. A more meaningful comparison is to consider the entire ECCS of both reactors, rather than the individual systems as it is the functionability of the Emergency Core Cooling System as a whole which is important.

Unavailability of either or both subsystems of the CSIS is dominated by the estimated outages for maintenance activities on the motor operated valves and pumps. System tests were not significant contributors to overall unavailability and no significant human error single faults were found.

Grand Gulf's LPCS unavailability is also dominated by maintenance contributions of the pump and valves. The RSS estimated a 6.0×10^{-2} median unavailability for either CSIS train. Grand Gulf's LPCS unavailability is calculated in Section 5.2.2 and varies from 2.2×10^{-2} to 3.5×10^{-2} depending on the initiator.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

The LPCS is one of four systems which provide emergency coolant injection to prevent core damage for LOCAs and transients. The other three systems are (1) the High Pressure Core Spray (HPCS), (2) the Low Pressure Core Injection System (LPCI), and (3) the Reactor Core Isolation Cooling System (RCIC).

The unavailability of the LPCS contributes to Event E (ECI) for both large and small LOCAs and Event V (Low Pressure ECCS) for transients. In all cases, successful core cooling can be accomplished by LPCS alone (assuming system pressure has been reduced through the break or by the ADS). Failure of the LPCS is defined as failure of the system to deliver ECCS water to the core when needed.

5.2 LPCS Model Description

5.2.1 LPCS Boolean Equations

Three equations of the LPCS were developed: one for LOCAs, one for T_1 sequences and one for T_{23} sequences. The LOCA LPCS Boolean equation differs from the others in that it includes failure caused by loss of emergency power division I after a LOCA induced loss of offsite power. The T_1 equation includes

the possibility of not recovering offsite power and also losing emergency power division 1. In T_{23} sequences, AC power is assumed to be available. These equations are:

$$LPCS\ (LOCAs) = L + LLOP*EPS1 + LRACT.$$

$$LPCS\ (T_1) = L + LOPNRE*EPS1 + LRACT.$$

and

$$LPCS\ (T_{23}) = L + LRACT.$$

Table B7-1 relates each term in the above equations to the components shown in Figure B7-1. Table B7-2 lists total component unavailabilities and each of the contributors to the component unavailability. These unavailabilities include hardware, maintenance, and human faults when applicable.

While testing of the LPCS components was found to be negligible due to a test override capability, a test unavailability of 2.3×10^{-4} was estimated for downtime due to LPCS logic circuit testing. This number was obtained by assuming a biannual, 1 hour test of LPCS initiating circuits.

The average maintenance interval used in the Reactor Safety Study is 4.5 months, which corresponds to a frequency of .22 per month. The unavailability of a component due to maintenance is estimated to be

$$Q_{maintenance} = \frac{\bar{t}\ (.22)}{720} ,$$

where $\bar{t}$ is the mean maintenance duration. Using a $\bar{t}$ of 19 hours for pumps and valves we find

$$Q_{pump\ and\ MOV\ maintenance} = 5.8 \times 10^{-3}$$

The only human error significantly contributing to LPCS failure was the failure to return valve F007 to normal condition after maintenance. Since this valve is normally locked open, an RSS value of 1×10^{-4} was used as the unavailability due to human error.

A common mode failure exists between the LPCS and RHR loop A. These systems share a common initiating circuit. A 1.2×10^{-3} common mode unavailability was attributed to this initiating circuit. Refer to Appendix B10 and Figure B7-2.

LPCS failure due to flow diversion through the minimum flow or test lines was found not to be significant. The minimum flow part of the line is only four inches in diameter. Therefore, only a small part of the flow would be diverted away from the 16-inch LPCS line. The test line is 14 inches in diameter, however, the MOV in this line is closed automatically on LPCS initiation and its position is indicated in the control room.

5.2.2 LPCS Unavailability

Using the Boolean equations given in the last section and the term unavailabilities given in Table B7-1, independent LPCS point estimate unavailabilities can be calculated.

These are found to be:

$$\text{LPCS (LOCAs)} = 2.2 \times 10^{-2} ,$$

$$\text{LPCS } (T_1) = 3.5 \times 10^{-2} ,$$

and

$$\text{LPCS } (T_{23}) = 2.2 \times 10^{-2} \quad .$$

A quantitative ranking of the Boolean terms for each equation is given in Table B7-3. It is evident from this table that term L dominates. Term L represents the combined hardware and maintenance unavailability contributions for all LPCS components. Calculations show that component maintenance makes up approximately 46 percent or more of the total LPCS unavailability.

The reader should be cautioned that these are unavailabilities for Grand Gulf's LPCS if the system is considered independent of all others. In general, LPCS unavailability will depend on what other system successes or failures have occurred, i.e., the unavailabilities used for the LPCS in the sequence analyses must be conditional unavailabilities.

Table B7-1. Boolean Equation Term Descriptions*

Boolean Term	Term Definition	Term Unavailability
L	F001-A + C001-A + F003 + F005-A + F006 + F007	2.1×10^{-2}
LLOP	LOCA induced loss of offsite power	1×10^{-3}
EPS1**	Emergency AC Power Division 1	6.7×10^{-2}
LOPNRE	Failure to recover offsite power in 30 minutes	2×10^{-1}
LRACT	LPCS and RHR A initiating logic circuit	1.2×10^{-3}

*Refer to Figure B7-1.
**Refer to Appendix B2.

Table B7-2. Component Unavailabilities

Component Description	Fault Identifiers	Failure Contributors	Q/Component
Check Valve	F003 F006	Hardware	1×10^{-4}
		Q Total	1×10^{-4}
Manual Valve (Normally Locked Open)	F007	Operator Error	1×10^{-4}
		Plugged	1×10^{-4}
		Q Total	2×10^{-4}
Pump	C001-A	Hardware	1×10^{-3}
		Control Circuit	1×10^{-3}
		Maintenance	5.8×10^{-3}
		Q Total	7.8×10^{-3}
Motor Operated Valve (Normally Keylocked Open)	F005-A	Hardware	1×10^{-3}
		Plugged	1×10^{-4}
		Maintenance	5.8×10^{-3}
		Control Circuit	3×10^{-4}
		Q Total	7.2×10^{-3}
Motor Operated Valve (Normally Keylocked Open)	F001-A	Plugged	1×10^{-4}
		Maintenance	5.8×10^{-3}
		Q Total	5.9×10^{-3}
Initiation Logic Circuit	LRACT	Fails to Function	1×10^{-3}
		Testing	2.3×10^{-4}
		Q Total	1.2×10^{-3}

Table B7-3. Quantitative Ranking of Boolean Terms

For LOCAS

L	2.1×10^{-2}
LRACT	1.2×10^{-3}
LLOP*EPS1	6.7×10^{-5}
	2.2×10^{-2}

For T_1 Transients

L	2.1×10^{-2}
LOPNRE*EPS1	1.3×10^{-2}
LRACT	1.2×10^{-3}
	3.5×10^{-2}

For T_{23} Transients

L	2.1×10^{-2}
LRACT	1.2×10^{-3}
	2.2×10^{-2}

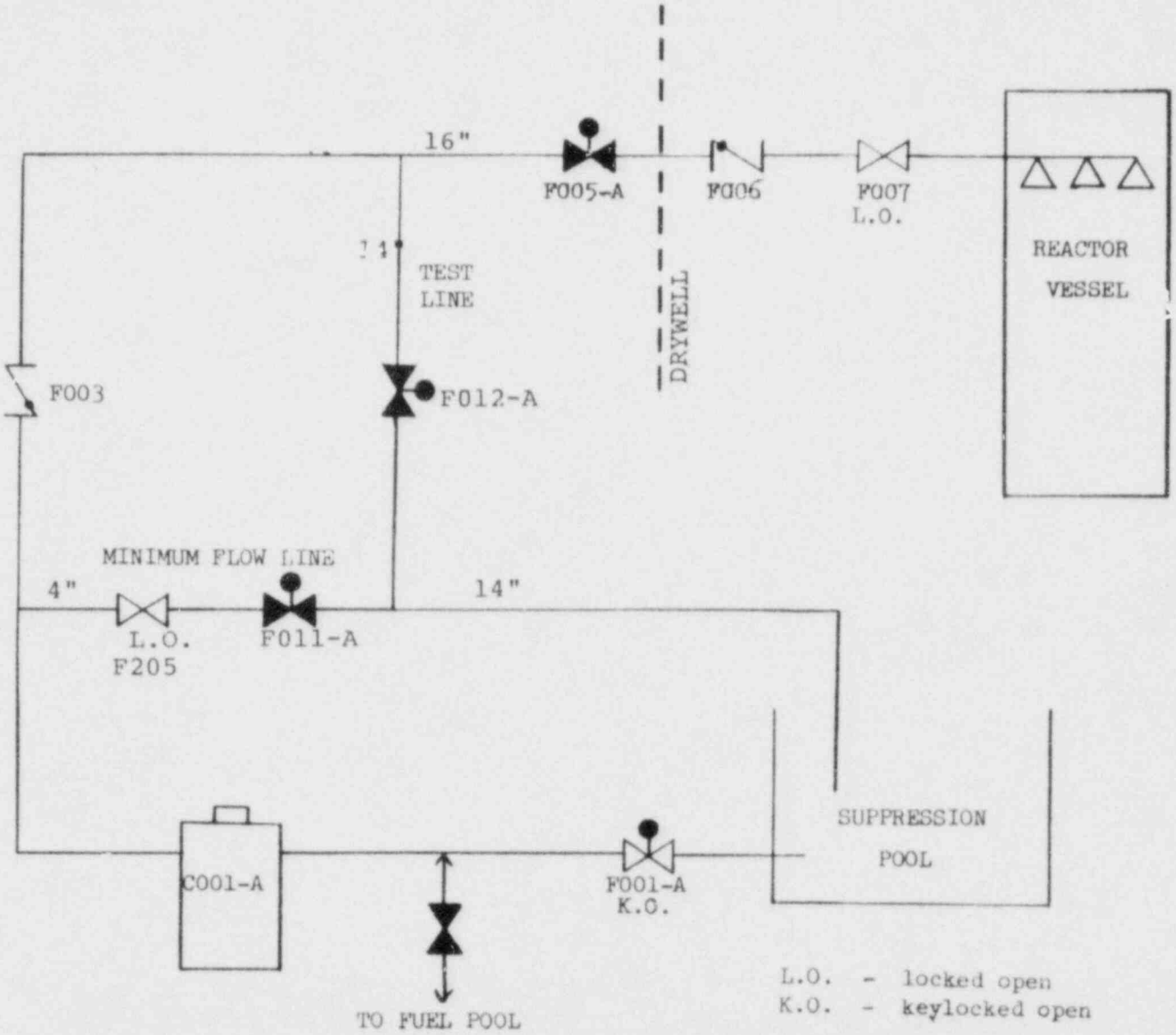
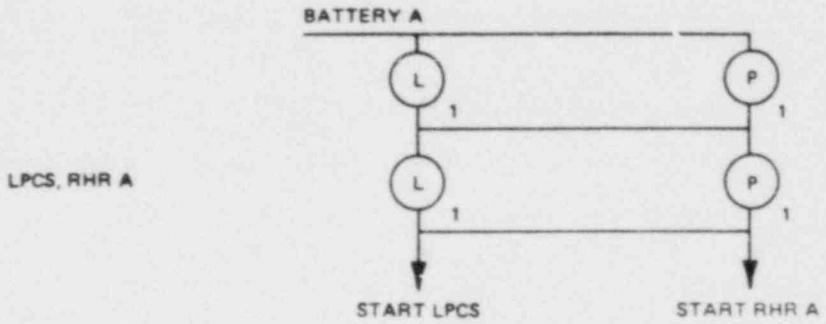


Figure B7-1. Grand Gulf Low Pressure Core Spray

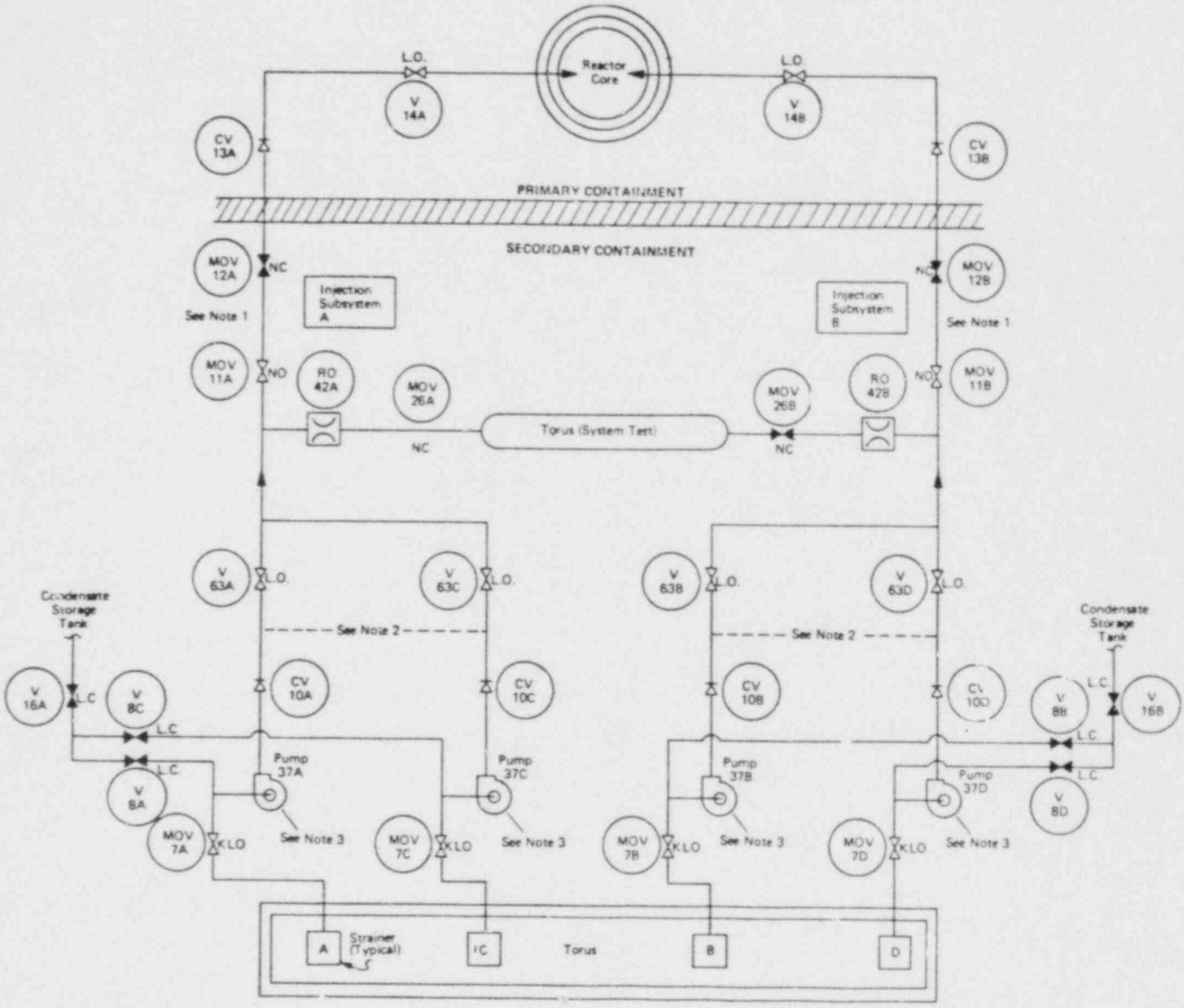


L = LOW REACTOR WATER LEVEL

P = HIGH DRYWELL PRESSURE

THE NUMBER 1 REPRESENTS ELECTRICAL DIVISION 1.

Figure B7-2. LPCS Initiating Logic



NOTES: 1 Interface with pump discharge line venting system.
2 Interface with pump discharge line filling system(COND./COND. SERV. SYS.).
3 Interface with pump room compartment/oil coolers (Emergency Service Water System).

Figure B7-3. Peach Bottom CSIS Simplified Flow Diagram

APPENDIX B8

SURVEY AND ANALYSIS

AUTOMATIC DEPRESSURIZATION SYSTEM (ADS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf Automatic Depressurization System (ADS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The ADS designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report respectively. A comparison of the two depressurization systems is given in Section 4. ADS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate ADS failures into the Grand Gulf accident sequences and a point estimate of the ADS unavailability assuming independence from all other Grand Gulf systems.

2.0 GRAND GULF ADS DESCRIPTION

2.1 System Description

The Automatic Depressurization System works in conjunction with the other systems of the ECCS to insure cooling of the reactor core following an accident. The ADS utilizes eight of the safety/relief valves to reduce the reactor pressure to the operating range of the low pressure ECCS subsystem when the High Pressure Core Spray (HPCS) or Reactor Core Isolation Cooling System (RCIC) fail to maintain the water level. The ADS is necessary only for small LOCAs and transients where the high pressure injection systems fail. It is not required for large LOCAs as the vessel will depressurize through the pipe break in these cases.

The ADS valves are located on the main steam lines between the reactor vessel and the first isolation valve within the

drywell. There are twenty safety/relief valves in total, eight of which belong to the ADS. The ADS valves have two solenoid pilot valves each of which has its own accumulator. A check valve on the accumulator inlets maintains the accumulator pressure. The air accumulators are recharged by two air receivers. The pneumatic supply system is sized to be capable of opening the valves and holding them open against the maximum drywell pressure of 30 psig. Each valve discharges the steam through a line which terminates below the minimum water level line in the suppression pool.

2.2 System Operation

Two redundant and separate logic systems are used to actuate the solenoid valves on the safety/relief valves. Each logic train reacts to the initiating signals by engaging one of two pilot valves on each of the safety/relief valves. In contrast to other ECCS systems in which initiating signals were arranged in a one-out-of-two twice logic, the initiating ADS sensors are series connected such that all initiating signals in at least one actuation division must be present to actuate the ADS (See Figure B8-1). Each logic train has two low vessel level sensors, two high drywell pressure sensors, one confirmed low water level sensor and a two-minute delay timer. In addition, the ADS will not start until operation of at least one of the low pressure systems is verified (See Figure B8-2). After initiation, the system may be reset to delay or prevent the system depressurization. All components have complete monitoring of system status in the

control room. The ADS may also be manually initiated by a control room operator.

3.0 PEACH BOTTOM ADS DESCRIPTION

The ADS of the Peach Bottom reactor performs the same function as the Grand Gulf ADS. The Peach Bottom system uses five safety/relief valves which are actuated by low reactor water and high drywell pressure. Each valve has an air accumulator which operates a solenoid pilot valve. The valves vent the steam to the suppression pool. If the High Pressure Coolant Injection System and Reactor Core Isolation Cooling System do not work, the ADS automatically reduces the pressure to the operating range of the Low Pressure Coolant Injection System or the Core Spray Injection System provided that one of these systems is operating. Initiation requires three signals: high drywell pressure, vessel low low water level, and confirmed low water level. A two-minute timer delays the actual initiation. During a LOCA, these valves are the only method of depressurization since the other manual valves outboard of the primary containment have been rendered useless with containment isolation. Two redundant control systems are used to initiate the ADS valve openings.

4.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM ADS

The two ADS systems of Grand Gulf and Peach Bottom are identical in purpose and very similar in design. The circuitries, including the initiating sensors, are almost identical. The major difference is in the valve hardware. The Grand Gulf valves have two solenoid pilot valves, each connected to a

different control circuit and each having its own accumulator. The Peach Bottom valves each have one pilot valve and accumulator which can be operated by either of two control systems. Grand Gulf uses eight safety/relief valves as ADS valves, any four of which that function results in system success for the worst small break case. At Peach Bottom, five valves belong to the ADS and three of five must function. In both cases, a manual intervention is possible which resets the timer to zero each time it is employed.

The dominant failure contributions for the ADS were the same for Grand Gulf and Peach Bottom. These are the failure of the operator to actuate the ADS after a transient (1.5×10^{-3} per reactor-year) and the unavailability of the two logic circuits to actuate the ADS after a small LOCA (5.0×10^{-3} per reactor-year).

As in Peach Bottom, the ADS unavailability due to loss of all D.C. power was found to contribute negligibly to the total unavailability at Grand Gulf. Failure of enough ADS valves to open was also found to be negligible at both plants.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

The failure probability of the ADS contributes to the probability of occurrence of Event V (Low Pressure ECCS) for transient sequences. At this point in the sequence the high pressure injection systems have failed. The ADS must now function to reduce system pressure so that the low pressure systems can operate. It was expected that during a transient, monitored

containment parameters do not reach the LOCA initiation setpoints so that manual actuation by the operator is required. Failure of the ADS for this case is failure of the operator to take action.

The ADS failure probability also contributes to Event E (Emergency Core Injection) occurrence probability for the small and transient induced LOCA sequences. For small (S) LOCAs failure of the ADS is defined as failure of the two controlling logic circuits to automatically actuate the system. The operator could manually open the valves in this case, but because of the high stress condition anticipated to exist at the time of a LOCA, such manual action is judged to be unlikely. For transient induced LOCAs (TPQ), it is assumed that manual actuation of the ADS is required for successful low pressure injection despite depressurization effects of the stuck open valve. Computer calculations made by Battelle Columbus laboratories indicates that, for TPQE sequences, core uncovery will occur about 40 minutes prior to when rated LPCS flow would be established without ADS actuation.

5.2 ADS MODEL DESCRIPTION

5.2.1 ADS Boolean Equations

Two different ADS equations were used in the sequence analyses. The first depicts ADS failure due to operator error and the other depicts ADS failure due to loss of both control circuits. These equations are:

$$\text{ADS (Transients)} = \text{OP} \quad ,$$

and

$$ADS\ (Small\ LOCAs) = ADSCM.$$

Testing and maintenance of the ADS system did not add to the unavailability as test procedures did not render the system inoperative and maintenance occurs only during shutdown because the ADS valves are located inside the primary containment.

Failure of both ADS automatic actuation control circuits which are demanded under LOCA conditions is dominated by a common mode failure involving a human error in the calibration of the actuation sensors. This was not important in the other ECCS subsystems due to the one-out-of-two twice logic of the initiating sensors. In the case of the ADS, the sensors are arranged in series and one failure will fail that logic train. It was assumed that incorrect calibration of one sensor would tend to be repetitively performed on other sensors of the same type. As stated previously, automatic actuation of the ADS is not expected to occur under transient conditions. Failure of the ADS under transient conditions was judged to be dominated by the operator error of not manually actuating the system.

5.2.2 ADS Unavailability

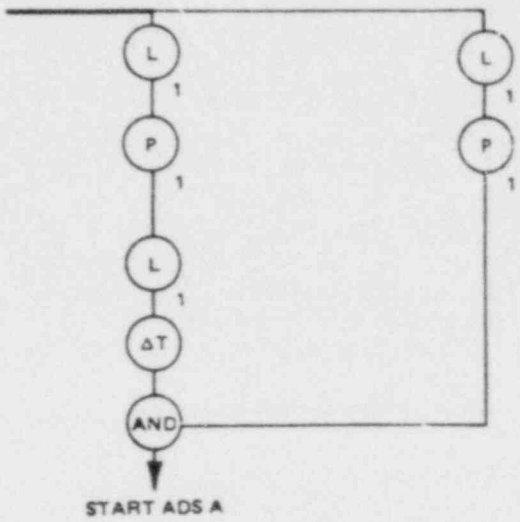
The unavailability number used for the ADS for transient sequences was the same as used in the Reactor Safety Study. A 1.5×10^{-3} unavailability was used for failure of the operator to manually actuate the ADS. Accordingly,

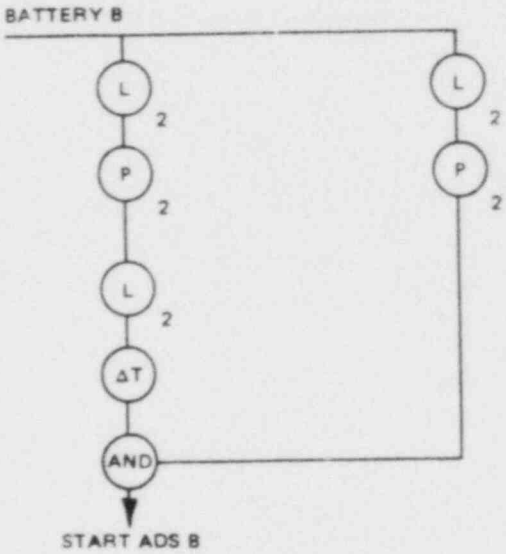
$$OP = 1.5 \times 10^{-3} \quad .$$

Because of the similarities in the ADS circuitry for the Grand Gulf and Peach Bottom plants, the ADS control circuit unavailability number used for the small LOCA sequences was derived in the same manner as done in the Reactor Safety Study.[1] The unavailability of one sensor in a logic train due to incorrect calibration is 1×10^{-2}. Miscalibration of a second sensor in the logic train would be more probable, 1×10^{-1}, and the chance of miscalibrating a third sensor approaches 1.0. If the ADS logic train was totally independent, ADS unavailability would be 9×10^{-4}; if completely coupled, it would be 3×10^{-2}. The log normal median was chosen as the unavailability of the system which is 5×10^{-3}. So,

$$ADSCM = 5 \times 10^{-3} .$$

[1] Refer to the Reactor Safety Study, page II-404.





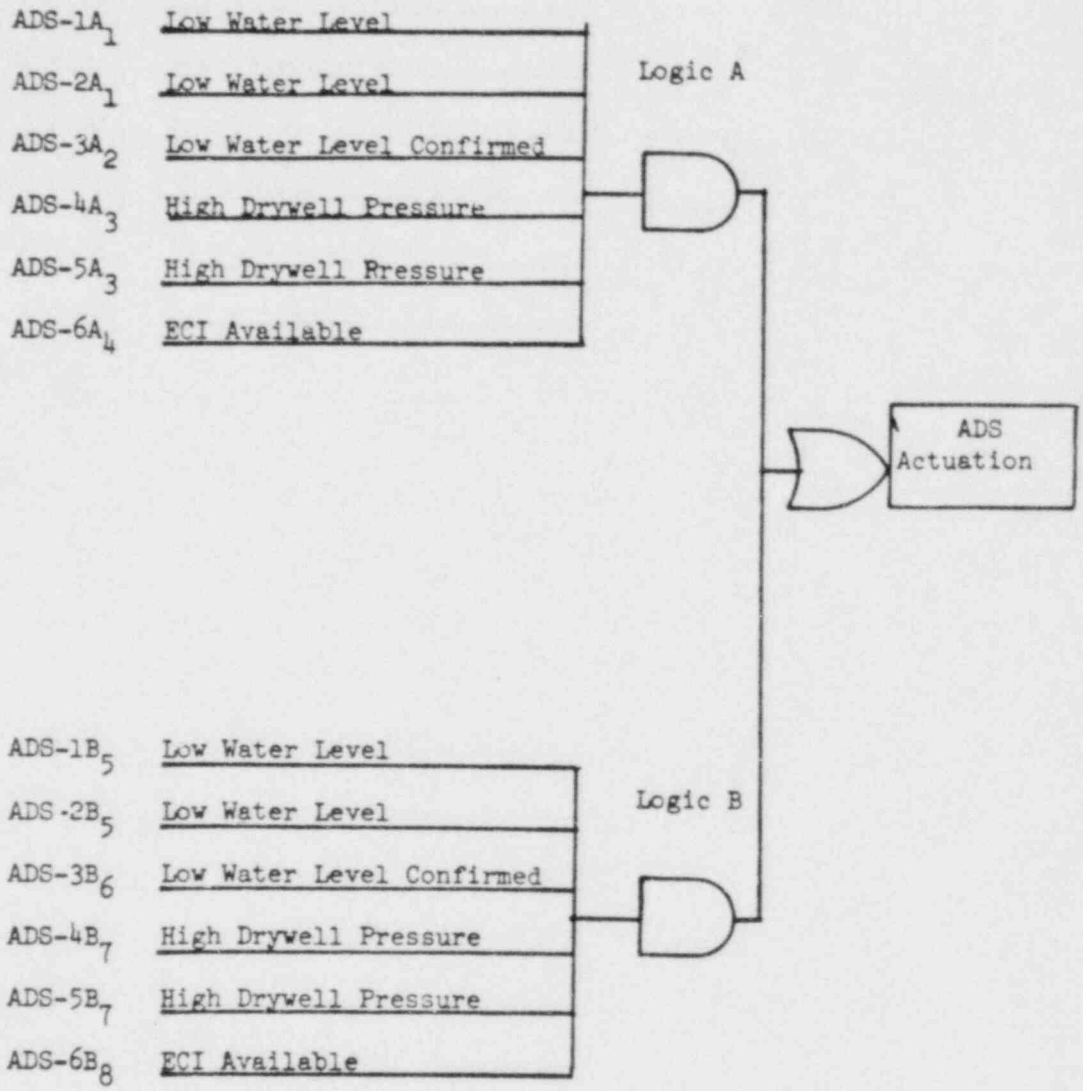
L = LOW REACTOR WATER LEVEL

P = HIGH DRYWELL PRESSURE

ΔT = TIME DELAY

1 AND 2 REPRESENT ELECTRICAL DIVISIONS

Figure B8-1. ADS Initiating Logic



All Sensors With The Same Subscript Are In The Same Bank

Figure B8-2. ADS Logic Schematic

APPENDIX B9

SURVEY AND ANALYSIS

LOW PRESSURE COOLANT INJECTION

SYSTEM (LPCIS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf Low Pressure Coolant Injection System (LPCIS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The LPCIS designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report respectively. A comparison of the two low pressure injection systems is given in Section 4. LPCIS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate LPCIS failures into the Grand Gulf accident sequences and a point estimate of the LPCIS unavailability assuming independence from all other Grand Gulf systems.

2.0 GRAND GULF LPCIS DESCRIPTION

2.1 System Description

The LPCIS represents an operating mode of the Residual Heat Removal System (RHRS). As can be seen from Figure B9-1, the RHRS includes a number of pumps and heat exchangers that can be used to cool the nuclear system in a variety of situations. The LPCIS is a part of the Emergency Core Cooling System, providing coolant injection into the reactor vessel through three redundant loops. Water is drawn from the suppression pool and injected through three independent nozzles into the reactor vessel. The LPCIS provides inventory makeup for large LOCAs, and also for small LOCAs and transients when working in conjunction with the Automatic Depressurization System (ADS).

The functional design basis of the LPCIS is to pump a total rate of 21200 gpm of water per loop into the reactor vessel. The pumps are protected by an automatic minimum flow valve system which automatically provides a flow path should the pump discharge valves be closed. In addition, the discharge lines are kept full of water by three jockey pumps to protect against possible shock waves upon pump startup. The pump, piping, controls, and instrumentation of the LPCIS loops are separated physically and functionally such that no single event can make all three loops inoperable. (The A loop is separated from the B and C loops.) Each division receives power from different AC buses, loop A from Division I and and loops B and C from Division II, and each has emergency on-site AC backup capabilities.

2.2 System Operation

The LPCIS requires no operator action for at least ten minutes following a LOCA. The system is initiated on redundant signal of high drywell pressure and low vessel water level. As shown in Figure B9-2, LPCI loop A is initiated by a logic circuit separate from the one initiating loops B and C. Before initiation, all valves except the inboard isolation valves are aligned to deliver the coolant directly into the core. The suppression pool suction valves F004A-A, F004B-B, and F004C-B are normally keylocked open and require no action. The automatic sequencing includes:

- The staggered starting of all three pumps to prevent electrical overload.

- The signalling to close of valves in the minimum flow, test, and crosstie lines, even though these valves are all normally closed.

- The signalling to open of valves F042A-A, F042B-B, F242-B, F027A-A, F027B-B, F048A-A, and F048B-B of which only the first three are normally closed.

Operation of the other RHRS modes is prevented for ten minutes by the LPCIS timer. Refer to Appendix B10 for an analysis of the RHRS system for long-term cooling.

3.0 PEACH BOTTOM LPCIS DESCRIPTION

A simplified flow diagram of the RHRS of the Peach Bottom reactor is shown in Figure B9-3. It consists of heat exchangers, pumps, and associated piping used to cool the nuclear system. One operating mode of the RHRS is Low Pressure Coolant Injection. It provides inventory makeup after a large LOCA, and following small LOCAs if the ADS reduces the reactor pressure. The LPCIS draws water from the suppression pool through four AC motor-driven centrifugal pumps. The major equipment is grouped in two divisions, each consisting of two pumps in parallel, two heat exchangers, associated piping and valves, and a connection to a recirculation loop. The two loops are separated physically and electrically. A single line connects the loops, making it possible for the pumps of one loop to supply the other. Although the flow passes through the heat exchangers, no tube side flow is necessary as this mode of operation is concerned only with

cooling by reflood. The system is initiated on low vessel water level and high drywell pressure signals from redundant sensors. The control system also selects the proper injection loop to use if the LOCA is in one of the recirculation lines that the LPCIS feeds to.

4.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM LPCIS

Although the primary functions of each system are the same, the designs are quite different. The Peach Bottom system is only two loops and these feed to the reactor through the recirculation lines (which are involved in the LOCA sequence). The Grand Gulf LPCIS utilizes three loops which deliver coolant via three independent nozzles. Both systems have two separate divisions which are located separately and have different power sources. In the Grand Gulf system, two of the loops are in one division. The Grand Gulf system also has two lines which have heat exchangers. The LPCIS will deliver the coolant through these bypass lines and/or through the heat exchanger lines.

The dominant contributor to LPCIS unavailability at Peach Bottom was from maintenance of the various pumps and valves. This was also the dominant contributor at Grand Gulf. Over 50% of Grand Gulf's LPCIS loop unavailability was due to component maintenance.

No common mode failures were identified in Peach Bottom's LPCIS. A common mode failure was found between LPCI loops B and C at Grand Gulf. These loops share actuating circuits and electric power divisions. However, since loop A is redundant and separate of loops B and C, this common mode has little affect on the system unavailability.

The RSS estimated a 1.5×10^{-2} unavailability for Peach Bottom's LPCIS. Grand Gulf's LPCIS unavailability varies from 2.3×10^{-2} to 4.1×10^{-2} per loop depending on the initiator.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

The LPCIS mode of the Residual Heat Removal System (refer to Appendix B10) is part of Event E, Emergency Coolant Injection, on the LOCA Event Tree. Combinations of the LPCIS, HPCS, and LPCS are needed to reflood the core after a LOCA. Success of Event E is defined in Appendix A1. On the Transient Event Tree, the probability of LPCIS failure contributes to the occurrence of Event V, Low Pressure ECCS, operating in conjunction with the ADS or LPCS. Success of Event V is defined in Appendix A2.

Failure of the LPCIS is divided into failures of each specific loop. Failure of an LPCIS loop is defined as failure of that loop to deliver cooling water to the reactor vessel at design flow.

5.2 LPCIS Model Description

5.2.1 LPCIS Boolean Equations

Three equations of each LPCIS loop were developed: one for LOCAs, one for T_1 sequences, and one for T_{23} sequences. The LOCA equations differ from the others in that they include failure caused by loss of emergency power after a LOCA induced loss of offsite power. The T_1 equations include the possibility of not recovering offsite power and also losing emergency power. In T_{23}

sequences, AC power is assumed to be available. These equations are:

For LOCAs:

LPCIA (Loop A) = LA1 + LA2 + LLOP*EPS1 + LRACT ,

LPCIB (Loop B) = LB1 + LB2 + LLOP*EPS2 + BCACT ,

LPCIC (Loop C) = LC + LLOP*EPS2 + BCACT .

For T_1 Transients:

LPCIA (Loop A) = LA1 + LA2 + LOPNRE*EPS1 + LRACT ,

LPCIB (Loop B) = LB1 + LB2 + LOPNRE*EPS2 + BCACT ,

LPCIC (Loop C) = LC + LOPNRE*EPS2 + BCACT .

For T_{23}Transients:

LPCIA (Loop A) = LA1 + LA2 + LRACT ,

LPCIB (Loop B) = LB1 + LB2 + BCACT ,

LPCIC (Loop C) = LC + BCACT .

Table B9-1 relates each term in the above equation to the components shown in Figure B9-1. Table B9-2 lists fault identifiers that label specific components in the LPCIS and failures that contribute to the component unavailability. These unavailabilities include hardware, maintenance, and human faults when applicable.

While testing of LPCIS components was found to be negligible due to a test override capability, a test unavailability of 1.2×10^{-3} was estimated for downtime due to LPCIS logic circuit testing. This number was obtained by assuming a biannual, 1 hour test of LPCIS initiating circuits.

A common mode failure exists between the LPCS and LPCIS loop A. These systems share a common initiating circuit. A similar common

mode failure exists between LPCIS loops B and C. A 1×10^{-3} common mode unavailability was attributed to each of these initiating circuits. Refer to Appendix B7 and Figure B9-2.

The average maintenance interval used in the Reactor Safety Study is 4.5 months, which corresponds to a frequency of .22 per month. The unavailability of a component due to maintenance is estimated to be

$$Q_{maintenance} = \frac{t(.22)}{720} ,$$

where $\bar{t}$ is the mean maintenance duration. Using a $\bar{t}$ of 19 hours for pumps and valves, we find

$$Q_{pump\ and\ MOV\ maintenance} = 5.8 \times 10^{-3} .$$

The only human errors associated with LPCIS loop failure was the failure to return valves F039A, F029A, F039B, F029B, F239, and F029C to normal condition after maintenance. Since these valves are normally keylocked open, an RSS valve of 1×10^{-4} was used as the unavailability due to human error.

5.2.2 LPCIS Unavailability

Using the Boolean equations given in the last section and the term unavailabilities given in Table B9-1, independent LPCIS loop point estimate unavailabilities can be calculated. These are found to be

For LOCAs:

LPCIA = 2.8×10^{-2}

LPCIB = 2.8×10^{-2}

LPCIC = 2.3×10^{-2}

For T_1 Transients:

LPCIA = 4.1×10^{-2}

LPCIB = 4.1×10^{-2}

LPCIC = 3.6×10^{-2}

For T_{23} Transients:

LPCIA = 2.8×10^{-2}

LPCIB = 2.8×10^{-2}

LPCIC = 2.3×10^{-2}

A quantitative ranking of the Boolean terms for each equation is given in Table B9-3. It is evident from this table that terms LA1, LA2, LB1, LB2 and LC dominate the three loop equations. These terms represent the combined hardware and maintenance contributions for components in each individual LPCIS loop. Calculations show that component maintenance makes up approximately 46% or more of the total LPCIS unavailability of each loop.

The reader should be cautioned that these are unavailabilities for Grand Gulf's LPCIS if the system is considered independent of all others. In general, LPCIS unavailability will depend on what other system successes or failures have occurred, i.e., the unavailabilities used for the LPCIS in the sequences analysis must be conditional unavailabilities.

*Table B9-1. Boolean Equation Term Descriptions

Boolean Term	Term Definition	Term Unavailability
LA1	F039A + F041A + F042A-A + F027A-A	1.3×10^{-2}
LA2	F029A + F031A + C002A-A + F004A-A	1.4×10^{-2}
LB1	F039B + F041B + F042B-B + F027B-B	1.3×10^{-2}
LB2	F029B + F031B + C002B-B + F004B-B	1.4×10^{-2}
LC	F239 + F241 + F242-B + F029C + F031C + C002C-B + F004C-B	2.2×10^{-2}
LRACT	LPCS and RHR A Initiating Logic Circuit	1.2×10^{-3}
BCACT	RHR A and B Initiating Logic Circuit	1.2×10^{-3}
LLOP	LOCA Induced Loss of Offsite Power	1.0×10^{-3}
LOPNRE	Failure to Recover Offsite Power in 30 Minutes	2.0×10^{-1}
**EPS1	Emergency AC Power Division 1	6.7×10^{-2}
**EPS2	Emergency AC Power Division 2	6.7×10^{-2}

*Refer to Figure B12-1.
**Refer to Appendix B2.

Table B9-2. Component Unavailabilities

Component Description	Fault Identifiers	Failure Contributors	Q/Components
Check Valve	F031A F041A F031B F041B F241 F031C	Hardware	1×10^{-4}
		Q Total	1×10^{-4}/valve
Manual Valve (Locked Open)	F039A F029A F039B F029B F239 F029C	Operator Error	1×10^{-4}
		Plugged	1×10^{-4}
		Q Total	2×10^{-4}
LPCI Pump	C002A-A C002B-B C002C-B	Hardware	1×10^{-3}
		Control Circuit	1×10^{-3}
		Maintenance	5.8×10^{-3}
		Q Total	7.8×10^{-3}
Motor Operated Valve (Normally Closed)	F042A-A F042B-B F242-B	Hardware	1×10^{-3}
		Plugged	1×10^{-4}
		Maintenance	5.8×10^{-3}
		Control Circuit	3×10^{-4}
		Q Total	7.2×10^{-3}
Motor Operated Valve (Normally open)	F027A-A F004A-A F027B-B F004B-B F004C-B	Plugged	1×10^{-4}
		Maintenance	5.8×10^{-3}
		Q Total	5.9×10^{-3}
Initiation Logic Circuit Loop A	LRACT	Fails to Function	1×10^{-3}
		Testing	2.3×10^{-4}
		Q Total	1.2×10^{-3}
Initiating Logic Circuit Loops B and C	BCACT	Fails to Function	1×10^{-3}
		Testing	2.4×10^{-4}
		Q Total	1.2×10^{-3}

Table B9-3. Quantitative Ranking of Boolean Terms

LCIA - LOCAs:

LA2	1.4×10^{-2}
LA1	1.3×10^{-2}
LRACT	1.2×10^{-3}
LLOP*EPS1	6.7×10^{-5}
	2.8×10^{-2}

LPCIA - T_1 Transients:

LA2	1.4×10^{-2}
LA1	1.3×10^{-2}
LOPNRE*EPS1	1.3×10^{-2}
LRACT	1.2×10^{-3}
	4.1×10^{-2}

LPCIA - T_{23} Transients:

LA2	1.4×10^{-2}
LA1	1.3×10^{-2}
LRACT	1.2×10^{-3}
	2.8×10^{-2}

LPCIB - LOCAs:

LB2	1.4×10^{-2}
LB1	1.3×10^{-2}
BCACT	1.2×10^{-3}
LLOP*EPS2	6.7×10^{-5}
	2.8×10^{-2}

LPCIB - T_1 Transients:

LB2	1.4×10^{-2}
LB2	1.3×10^{-2}
LOPNRE*EPS2	1.3×10^{-2}
BCACT	1.2×10^{-3}
	4.1×10^{-2}

LPCIB - T_{23} Transients

LB2	1.4×10^{-2}
LB1	1.3×10^{-2}
BCACT	1.2×10^{-3}
	2.8×10^{-2}

LPCIC - LOCAs:

LC	2.2×10^{-2}
BCACT	1.2×10^{-3}
LLOP*EPS2	6.7×10^{-5}
	2.3×10^{-2}

Table B9-3 (Continued)

LPCIC - T_1 Transients:

LC	2.2×10^{-2}
LOPNRE*EPS2	1.3×10^{-2}
BCACT	1.2×10^{-3}
	3.6×10^{-2}

LPCIC - T_{23} Transients:

LC	2.2×10^{-2}
BCACT	1.2×10^{-3}
	2.3×10^{-2}

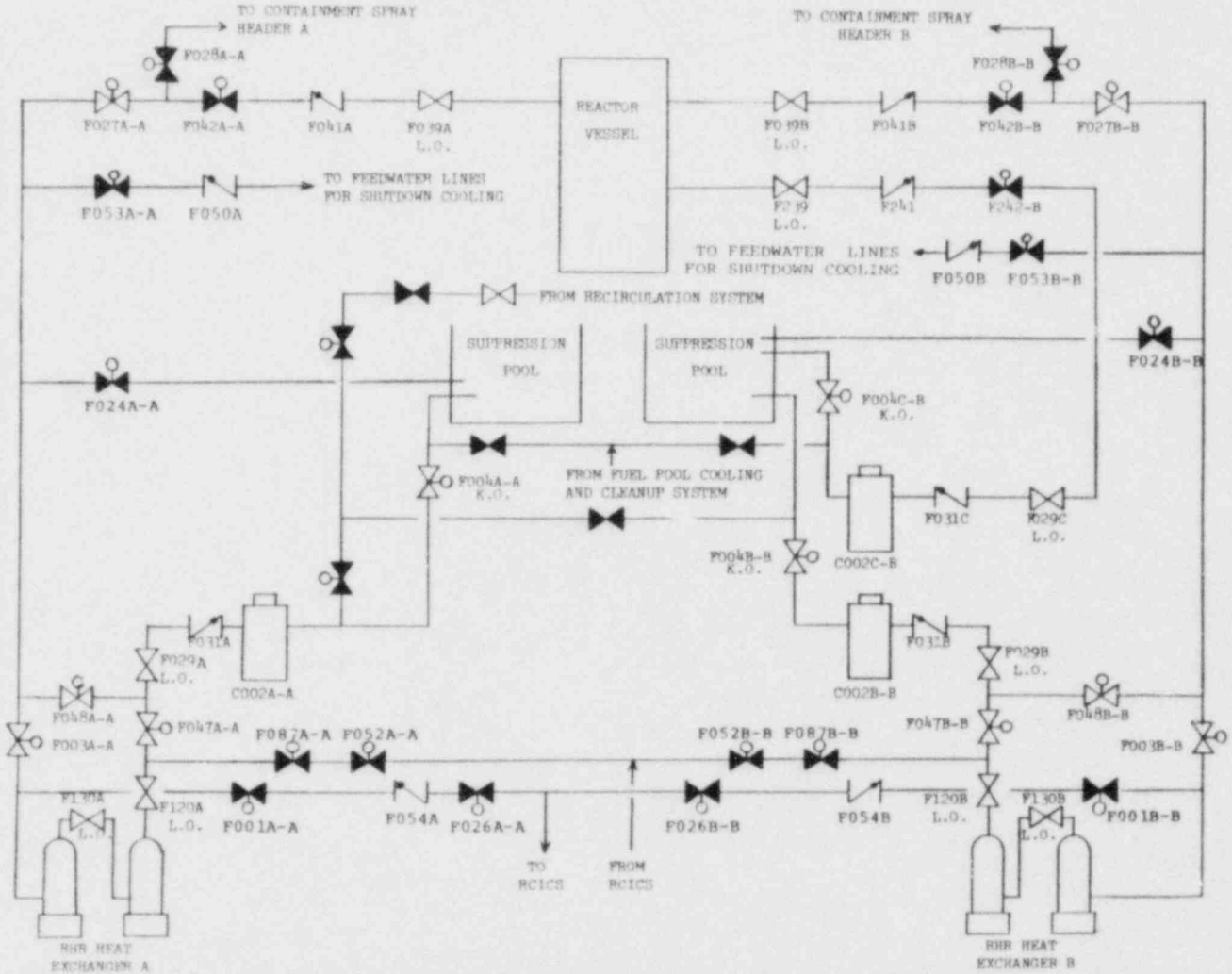
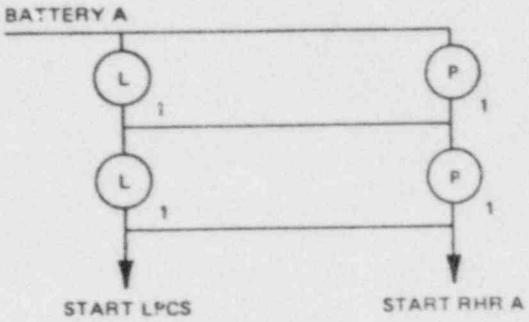
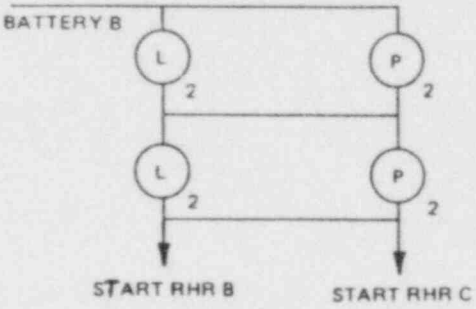
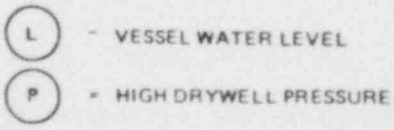


Figure B9-1. Grand Gulf Residual Heat Removal System







1 AND 2 REPRESENT ELECTRICAL DIVISIONS

Figure B9-2. LPCI (RHRS) Initiating Logic

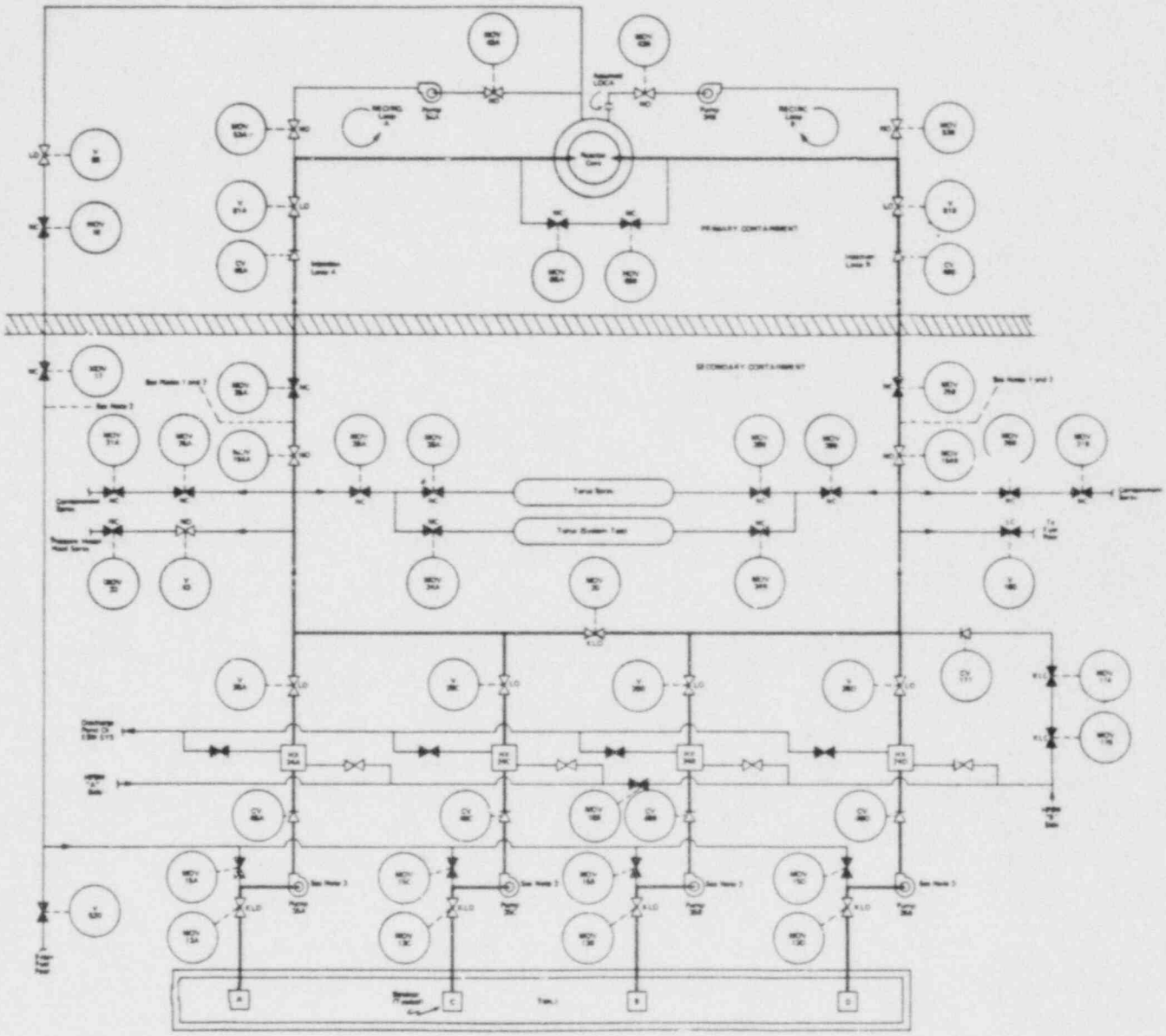


Figure B9-3. Peach Bottom LPCIS Simplified Flow Diagram

APPENDIX B10

SURVEY AND ANALYSIS

RESIDUAL HEAT REMOVAL SYSTEM (RHRS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf Residual Heat Removal System (RHRS) was reviewed and compared with the similar BWR design (Peach Bottom) evaluated in the WASH-1400 study. The RHRS design for Grand Gulf and Peach Bottom LPCRS are described in Sections 2 and 3 of this appendix respectively. A comparison of the two heat removal systems is given in Section 4. RHRS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate RHRS failures into the Grand Gulf accident sequences and a point estimate of the RHRS unavailability assuming independence from all other Grand Gulf systems.

2.0 GRAND GULF RHRS DESCRIPTION

2.1 System Description

The RHRS (Figure B10-1) consists of two separate flow paths (loops A and B) for removing decay and sensible heat from the primary containment. Each path includes an electric pump with a 21,200 gpm flow rate, a shell and tube heat exchanger and associated piping and valves. Long term core cooling is achieved by rejecting core decay heat to the Standby Service Water System via the RHR heat exchangers.

Credit is given for two different operating modes of the RHRS, the suppression pool cooling mode and the reactor steam condensing mode.

In the suppression pool cooling mode, water is drawn from the suppression pool by the RHR (LPCI) pumps, cooled by the RHR heat exchangers and returned to the suppression pool. The Standby

Service Water System (SSWS) is required to supply water to the secondary side of the heat exchangers.

The steam condensing mode of the RHRS utilizes the RCICS, SSWS, and RHR heat exchangers. Main steam, tapped off the RCICS steam line, is routed through the RHR heat exchangers and condensed. The condensate is then drawn off by RCICS suction. The functional design basis of the RHR steam condensing mode is that one loop of the RHRS, in conjunction with the RCICS, will be able to condense all the steam generated after a reactor scram, one and a half hours after the scram. Refer to Figure B10-2.

2.2 System Operation

The majority of the RHR equipment used in the suppression pool cooling mode is first used in an accident by the Low Pressure Core Injection System (LPCIS). Refer to Appendix B9 for the analysis of the LPCIS. In the LPCIS mode, water is drawn from the suppression pool and injected directly into the reactor vessel. Flow through loops A and B is bypassed around the RHR heat exchangers. As discussed in Appendix B9, no action can be taken before the 10 minute timer on the LPCIS times out. The operator may then manually initiate and align the RHRS by:

(1) Closing valves F048A-A and F048B-B, the heat exchanger bypass valves.

(2) Opening valves F014A-A, F014B-B, F068A-A, and F068B-B, the Standby Service Water inlet and outlet valves for the RHR heat exchangers, if closed. These valves will be open if a LOCA condition exists and are not shown

in Figure B10-1. Refer to Appendix B12 for the analysis of the Standby Service Water System.

(3) Opening valves F024A-A and F024B-B, the suppression pool return line valves, and closing F027A-A and F027B-B, the LPCIS injection line valves.

(4) Verifying that there is at east one complete path through a heat exchanger.

There are several suctions sources and discharge paths available for RHR loops A and B. Water can be drawn from the suppression pool or the recirculation system and can be injected into the LPCI lines or feedwater lines (as is done in the shutdown cooling mode) or directed back to the suppression pool. The RHRS is automatically aligned in the LPCI mode following an accident and all other paths are signaled closed. During the suppression pool cooling mode, the injection lines are closed and the return lines to the suppression pool are opened. No credit was given for any other flow path.

The RHR steam condensing mode is a manually operated system using components in both the RHRS and RCICS. To initiate the system, the operator must:

(1) Close the heat exchanger inlet and outlet valves (F003 and F047).

(2) Initiate RCICS operation.

(3) Open the RCICS steam supply and discharge valves (F087, F052, F001, and F026).

All operations are performed from the control room. The steam condensing mode of the RHRS was assumed to be unavailable after LOCAs.

3.0 PEACH BOTTOM LPCRS DESCRIPTION

A simplified flow diagram of the Low Pressure Coolant Recirculation System (LPCRS) of the Peach Bottom reactor is shown in Figure B10-3. This system performs the same function as Grand Gulf's RHRS and also consists of heat exchangers, pumps and associated piping used to cool the nuclear system. Three operating modes are defined:

(1) Shutdown Cooling and Vessel Head Spray. Water is drawn from the reactor system, cooled in the heat exchangers, and delivered back to the vessel through the recirculation lines or the vessel spray header.

(2) Low Pressure Coolant Injection. Suppression pool water is used to provide the inventory makeup function.

(3) Containment Cooling. The suppression pool water is cooled and returned to the pool or delivered to a spray header in the drywell.

The LPCRS at Peach Bottom is grouped in two loops, each consisting of two pumps in parallel, two heat exchangers in parallel, and piping to satisfy all of the operating modes defined above. The equipment in each loop is separated both in location and control, thus providing the redundancy necessary to assure successful operation. The heat exchangers receive their cooling water from the High Pressure Service Water System.

4.0 COMPARISON OF GRAND GULF RHRS AND PEACH BOTTOM LPCRS

Although the primary functions of each system are the same, the actual designs are quite different. The Peach Bottom system

consists of only two loops and these feed to the reactor through the recirculation lines. The Grand Gulf system has three loops, although only two of these have heat exchangers, and these loops deliver water to the vessel through three independent nozzles. The Peach Bottom RHRS does not have a steam condensing mode like at Grand Gulf. Both systems have two independent divisions which are located separately and have different power sources. Each of the Peach Bottom loops include two pumps and two heat exchangers which are in parallel, while the Grand Gulf loops each have only one pump and a heat exchanger which are in series.

The cooling water to the heat exchangers is supplied by the Standby Service Water System in the Grand Gulf unit. This system also supplies pump seal and compartment cooling. In Peach Bottom, the heat exchangers are cooled by High Pressure Service Water; while the pumps are cooled by a separate system, the Emergency Service Water System.

As discussed in the Reactor Safety Study (Appendix 2, page 425), the large number of pumps and paths available for cooling and recirculation of the reactor water at Peach Bottom allows for a great deal of diversity in coping with the heat removal task. Any one of the four LPCRS pumps could meet the cooling requirements. The dominant failure identified was a common mode in the Emergency Service Water, which cools the pump compartments. Potential faults in the ESWS output valve V506 contributed over 90% to LPCRS unavailability. Any plugging or failing of this valve will prevent coolant flow to all LPCRS unit coolers.

The unavailabilty of the LPCRS (equal to the unavailability of ESWS) was estimated in the RSS to be

$$Q(LPCRS) = 1.2 \times 10^{-4}$$

Grand Gulf's RHRS unavailability was dominated by hardware and maintenance faults in loops A and B that would occur during the low pressure injection phase of the accident. Service water valve faults were important contributors, but not dominant as in Peach Bottom's system. System failures of Grand Gulf's RHRS for the different accident initiators are given in Section 5.2.2 and are in the 3.0×10^{-3} range when steam condensing is not included in the analysis, an order of magnitude greater than Peach Bottom's. For long-term transient accidents, credit is given for steam condensing, and total RHR failure is calculated to be approximately 2.7×10^{-4}.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

The RHRS is the only system which provides long term cooling of the suppression pool and reactor vessel when the Power Conversion System (PCS) is not operating. The RHRS is considered in Event I on the LOCA event tree and Event W on the transient event tree. For LOCAs, failure of the RHRS is defined as failure of RHR loops A and B to function in the suppression pool cooling mode. For transients, RHR failure is defined as failure of RHR loops A and B to function in either the suppression pool cooling mode or the steam condensing mode. Refer to Appendices A1 and

A2 for more discussion on how the RHRS was incorporated into the analysis.

5.2 RHRS Model Description

5.2.1 RHRS Boolean Equations

The following Boolean equations were developed to model RHRS loop failure in the suppression pool cooling mode.

For LOCAs

RHRA (Loop A) = LA2 + LLOP*EPS1 + LRACT + PA27 + VGA1 + VGA2

RHRB (Loop B) = LB2 + LLOP*EPS2 + BCACT + PB27 + VGB1 + VGB2

For T_1 Transients

RHRA (Loop A) = LA2 + LOPNRL*LOPNRE*EPS1 + LRACT + PA27 + VGA1 + VGA2

RHRB (Loop B) = LB2 + LOPNRL*LOPNRE*EPS2 + BCACT + PB27 + VGB1 + VGB2

For T_{23} Transients

RHRA (Loop A) = LA2 + LRACT + PA27 + VGA1 + VGA2

RHRB (Loop B) = LB2 + BCACT + PB27 + VGB1 + VGB2

The terms LA2, LB2, LRACT, and BCACT are described in Appendix B9 and represent failures of the RHRS in the injection mode. If low pressure injection has succeeded, the residual heat removal can still fail due to:

Failure of the RHR pumps to continue running (terms PA27 and PB27). This failure was not included for sequences where high pressure injection succeeds.

Failure of the heat exchanger bypass valves to close, failure of the suppression pool return line valves to open, or failure of the RHR pump room or seal cooling service water valves (terms VGA2 and VGB2).

Failure of Standby Service Water System valves on the secondary side of the RHR heat exchangers or failure of certain manual valves on the primary side of the heat exchangers (terms VGA1 and VGB1).

The following equations were used to model the RHR steam condensing mode and were incorporated into the event W definition for transients. Refer to Appendix A2. The first equation represents steam condensing using RHR loop A. The second represents steam condensing using RHR loop B.

$$SCA = VGA1 + SCVA$$

$$SCB = VGB1 + SCVB$$

The terms SCVA and SCVB represent valve failures in the steam admission or discharge lines.

Table B10-1 relates each term in the above equations to the components shown in Figure B10-1. Table B10-2 lists total component unavailabilities and each of the contributors to the component unavailability. These unavailabilities include hardware, maintenance, and human faults when applicable.

The average maintenance interval used in the Reactor Safety Study is 4.5 months, which corresponds to a frequency of .22 per month. The unavailability of a component due to maintenance is estimated to be

$$Q_{maintenance} = \frac{\bar{t}(.22)}{720} \quad ,$$

where $\bar{t}$ is the mean maintenance duration. Using a $\bar{t}$ of 19 hours for pumps and valves, we find

$$Q_{pump\ and\ MOV\ maintenance} = 5.8 \times 10^{-3}$$

The only human error judged significant for the RHRS failure probability was the failure to return valves F120A, F120B, F130A, F130B, F210A, F210B, F083A, or F083B to normal condition (open) after maintenance. Valves F210A, F210B, F083A, and F083B are in the Standby Service Water System. For a manual valve that is closed during maintenance, the steady state probability that it will be found closed during a given month (unavailability) is estimated in the RSS to be the conditional probability

$$Q = p(\text{undetected/left closed}) \times p(\text{left closed/maint.}) \times p(\text{maint.})$$

where, p(undetected/left closed) = 1/3, is the estimated probability that the valve misalignment is not detected during walk-around plant inspections, p(left closed/maint.) = 10^{-2} is the basic human error of leaving the valve closed, and p(maint.) = 0.22 is the probability that maintenance took place the previous month, given a mean maintenance interval of 4.5 months. Therefore,

$$Q_{manual\ valve\ left\ open} = (.33)(.01)(.22) = 7.3 \times 10^{-4} \quad .$$

Manual valves F120A, F120B, F130A, and F130B are normally locked open and therefore are less susceptible to human error. An RSS valve of 1×10^{-4} was attributed to these valves due to this failure.

No human errors were included for inadvertent positioning of MOVs due to the amount of time the operators have for action and the fact that all critical MOV positions are annunciated in the control room.

No significant common mode failures were identified for RHRS operation.

5.2.2 RHRS Unavailability

Using the Boolean equations given in the last section and the term unavailabilities given in Table B10-1, independent RHRS loop point estimate unavailabilities can be calculated.

The suppression pool cooling loop unavailabilities are found to be:

For LOCAs

RHRA = 5.5×10^{-2}

RHRB = 5.5×10^{-2}

For T_1 Transients

RHRA = 5.6×10^{-2}

RHRB = 5.6×10^{-2}

For Q_{23} Transients

RHRA = 5.5×10^{-2}

RHRB = 5.5×10^{-2}

The steam condensing unavailabilities are found to be:

$SCA = 4.7 \times 10^{-2}$

$SCB = 4.7 \times 10^{-2}$

Complete failure of the RHRS for LOCAs is defined as failure of both RHR loops to provide suppression pool cooling. Therefore system failure can be calculated by multiplying the two loop equations together and quantifying. This gives:

RHRS (system failure, LOCAs)

= RHRA (LOCAs)*RHRB (LOCAs)

$= 3.0 \times 10^{-3}$

Complete failure of the RHRS for transients is defined as failure of both RHR loops to provide either suppression pool cooling or steam condensing.

RHRS (system failure, T_1 transients)

= RHRA (T_1)*RHRB (T_1)*SCA*SCB

$= 2.7 \times 10^{-4}$

RHRS (system failure, T_{23} transients)

= RHRA (T_{23})*RHRB(T_{23})*SCA*SCB

$= 2.7 \times 10^{-4}$

The reader should be cautioned that the RHRS unavailabilities stated here assume that the system is considered independent of all other systems. As mentioned above, however, RHRS unavailability will depend on what other system successes or failures have occurred, i.e., the unavailabilities used for the RHRS in the sequence analysis must be conditional unavailabilities.

(1)Table B10-1. Boolean Equation Term Descriptions

Boolean Term	Term Definition	Term Unavailability
LOPNRE	Failure to recover offsite power in one half hour	2.0×10^{-1}
LOPNRL	Failure to recover offsite power in 27 hours given LOPNRE	1.0×10^{-1}
PA27	RHR Pump A fails to continue running for about 30 hours	8.1×10^{-4}
PB27	RHR Pump B fails to continue running for about 30 hours	8.1×10^{-4}
(4)LA2	F004A-A + F031A + F029A + C002A-A	1.4×10^{-2}
(4)LB2	F004B-B + F031B + F029B + C002B-B	1.4×10^{-2}
(2)VGA1	F014A-A + F068A-A + F120A + F130A	1.5×10^{-2}
(2)VGB1	F014B-B + F068B-B + F120B + F130B	1.5×10^{-2}
(2)VGA2	F024A-A + F048A-A + F047A-A + F003A-A + F102A + F103A + F210A + F083A	2.4×10^{-2}
(2)VGB2	F024B-B + F048B-B + F047B-B + F003B-B + F102B + F103B + F210B + F083B	2.4×10^{-2}
SCVA	F003A-A + F047A-A + F087A-A + F052A-A + F001A-A + F026A-A + F054A	3.2×10^{-2}
SCVB	F003B-B + F047B-B + F087B-B + F052B-B + F001B-B + F026B-B + F054B	3.2×10^{-2}
LLOP	A LOCA induced loss of offsite power	1.0×10^{-3}

[1]Table B10-1. Boolean Equation Term Descriptions (Cont.)

Boolean Term	Term Definition	Term Unavailability
(4)LRACT	Initiating circuit RHR loop A	1.2×10^{-3}
(4)BCACT	Initiating circuit RHR loops B and C	1.2×10^{-3}
(3)EPS1	Emergency DC Power Division 1	6.7×10^{-2}
(3)EPS2	Emergency AC Power Division 2	6.7×10^{-2}

(1)Refer to Figure B10-1.

(2)Refer to Appendix B12.

(3)Refer to Appendix B2.

(4)Refer to Appendix B9.

Table B10-2. Component Unavailabilities

Component Description	Fault Identifiers	Failure Contributors	Q (per component)
Check Valve	F054A,F054B	Hardware	1.0×10^{-4}
		Q Total	1.0×10^{-4}
Motor Operated Valve (Normally Open, Must Close)	F048A-A		
	F048B-B		
	*F003A-A		
	*F003B-B		
	*F047A-A	Hardware	1×10^{-3}
	*F047B-B	Control Circuit	3×10^{-4}
		Q Total	1.3×10^{-3}
Manual Valve (Normally Locked Open)	F120A		
	F130A		
	F120B	Human Error	1×10^{-4}
	F130B	Plugged	1×10^{-4}
		Q Total	2×10^{-4}
Manual Valve (Normally Open)	F102A		
	F102B		
	F103A		
	F103B		
	F210A		
	F210B		
	F083A	Human Error	7.3×10^{-4}
	F083B	Plugged	1.0×10^{-4}
		Q Total	8.3×10^{-4}
Motor Operated Valve (Normally Closed)	F014A-A		
	F014B-B		
	F068A-A		
	F068B-B		
	F087A-A		
	F087B-B		
	F052A-A		
	F052B-B		
	F001A-A		
	F001B-B		
	F026A-A	Hardware	1.0×10^{-4}
	F026B-B	Control Circuit	3.0×10^{-4}
	F024A-A	Plugged	1.0×10^{-4}
	F024B-B	Maintenance	5.8×10^{-3}
		Q Total	7.2×10^{-3}
Motor Operated** Valve (Normally Open)	F003A-A		
	F003B-B		
	F047A-A	Plugged	1.0×10^{-4}
	F047B-B	Maintenance	5.8×10^{-3}
		Q Total	5.9×10^{-3}

*For steam condensing
**For suppression pool cooling

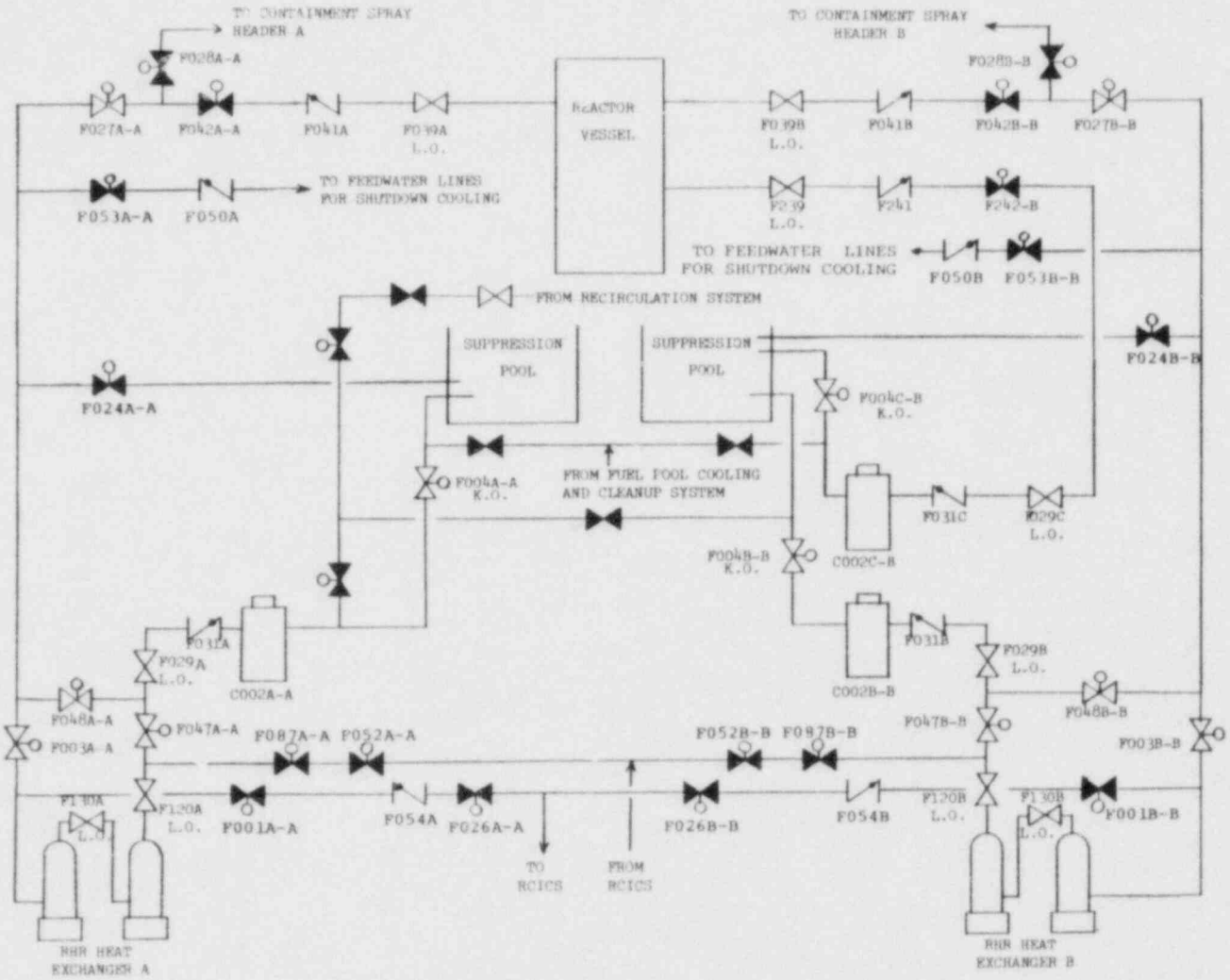

Figure B10-1. Grand Gulf Residual Heat Removal System

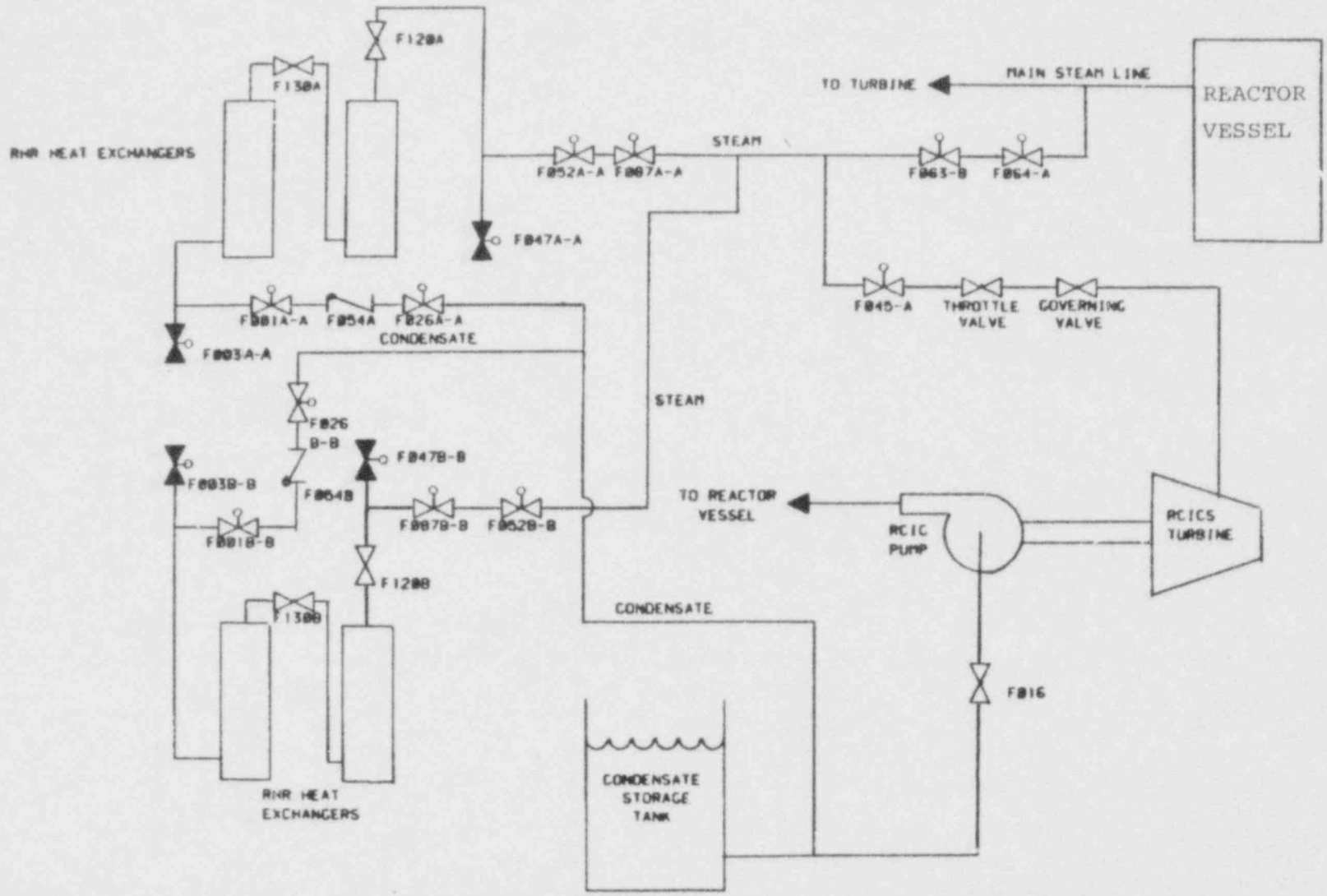

Figure B10-2. Grand Gulf RHR Steam Condensing Mode

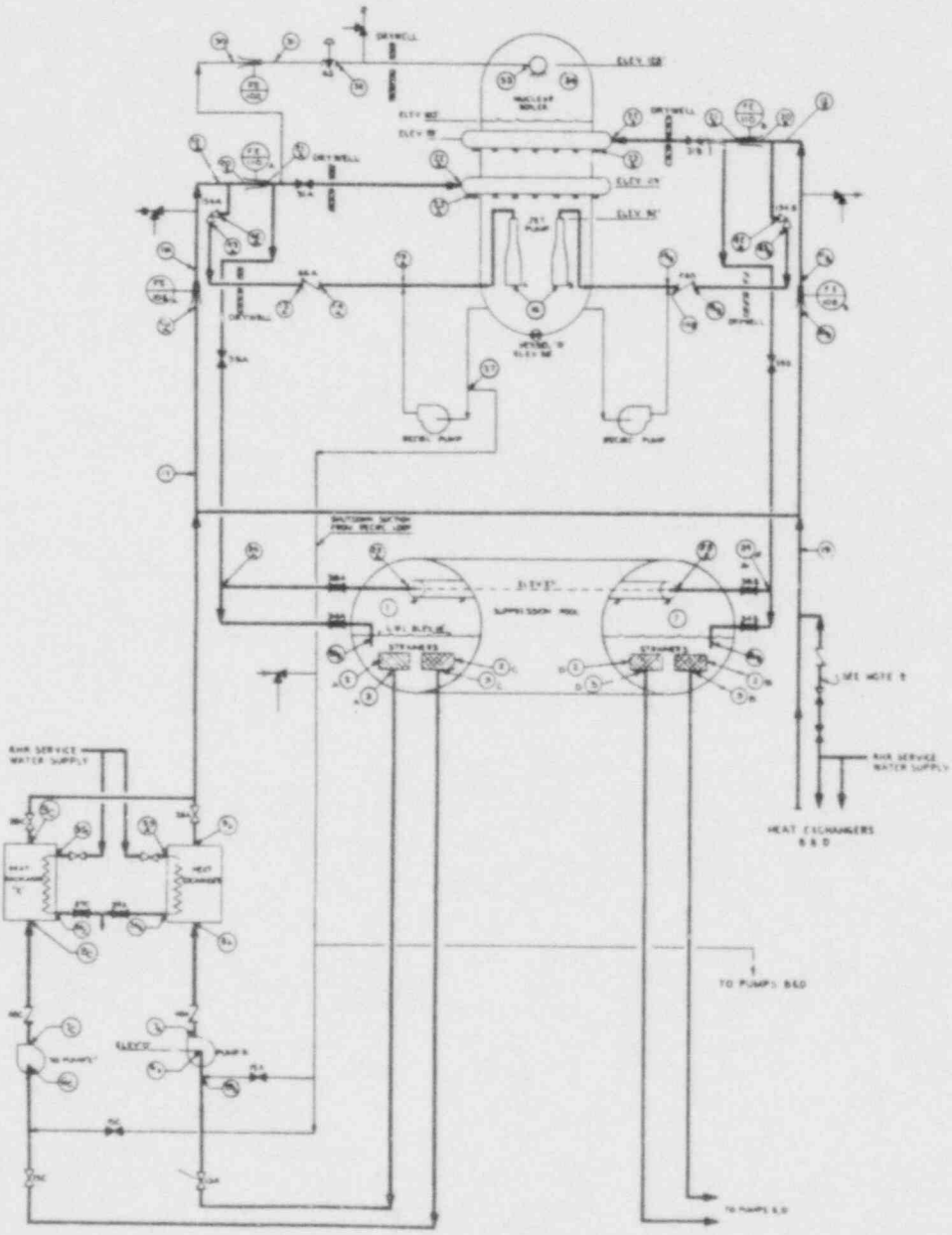

Figure B10-3. Peach Bottom Residual Heat Removal System

APPENDIX B11

SURVEY AND ANALYSIS

SUPPRESSION POOL MAKEUP SYSTEM (SPMS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf Suppression Pool Makeup System (SPMS) was reviewed to determine the applicability of the WASH-1400 analysis. The purpose of this analysis was to determine the impact on risk from the SPMS. Since there was no equivalent system in the WASH-1400 BWR (Peach Bottom) analysis, a comparison between Grand Gulf and Peach Bottom was not possible. The Grand Gulf SPMS is described in detail in the next section. SPMS Event tree interrelationships are discussed in Section 5. Also included in Section 5 is a description of the model used to incorporate SPMS failures into the Grand Gulf accident sequences.

2.0 GRAND GULF SPMS DESCRIPTION

2.1 System Description

As shown in Figure B11-1, the suppression pool makeup system provides water from the upper containment pool to the suppression pool by gravity flow following a LOCA. The piping system consists of two 100% capacity lines which penetrate the separator end of the upper containment pool through the side walls. One line is on either side of the separator pool and then routed down to the suppression pool on opposite sides of the steam tunnel. The elevation of the separator pool penetrations is such as to limit the volume of water which can be dumped into the suppression pool. This volume limitation, along with adequate weir wall freeboard insures that no drywell flooding over the weir wall will occur for inadvertent opening of the valves on the suppression pool makeup lines.

Each suppression pool makeup line has two normally closed valves in series. The power supply to valves on each line is from the same

electrical division. The opening of the makeup system valves is signaled by a series combination of low-low suppression pool level and a LOCA signal permissive. The low-low level signal is 18 inches below the normal low water level. Since maximum ECCS pump flow lowers the suppression pool at a rate of 0.86 ft/min, there is at least a 1.5-minute delay between start of ECCS flow and dumping of the upper pool. The delay is actually 1 to 2 minutes longer than this because vessel inventory mass is added to the suppression pool during blowdown steam condensation. This built-in volume integration delay assures that the drywell pressure transient due to vessel blowdown has ended prior to complete dumping of the upper pool and corresponding increase of vent submergence. The dump of the upper pool on low-low suppression pool level insures adequate water volume to keep the suppression pool vents covered for all break sizes.

There are four level switches indicating suppression pool water level with two switches per electrical division. The two level switches in one division are paralleled so that either switch will initiate suppression pool makeup flow (pending LOCA permissive) from the makeup line whose series valves are on the same electrical division as the level switches. In other words, level switches on one electrical division cannot initiate flow from the makeup line whose valves are in a separate electrical division.

The makeup system dump valves can also be signaled to open by a LOCA signal in series with a 30-minute timer where the timer itself is started by the LOCA signal. This path of initiation logic is parallel with the suppression pool low level along with a LOCA permissive and is specifically directed towards insuring that the combined upper

pool and suppression pool volumes are available as a heat sink for small breaks which do not lower the suppression pool to the low-low water level trip, but continue to dump vessel blowdown energy into the pool.

The automatic LOCA signal which provides a permissive for upper pool dump is paralleled with the manual ECCS initiation signal for the respective Divisions 1 and 2. Thus, the upper pool can be dumped manually. The 30 minute timer will, however, give the operator time for corrective action if an automatic upper pool dump is not desired. There is single failure protection against an automatic inadvertent dump. The LOCA signal plus the timer signal after 30 minutes will dump the upper pool. However, the LOCA signal itself is a one-out-of-two twice combination of high drywell pressure and low vessel water level and therefore a double failure is required to give a spurious LOCA signal.

The minimum suppression pool volume, without upper pool dump is adequate to meet all heat sink requirements for any combination sequence of vessel blowdown energy and decay heat energy out to 30 minutes. The capacity of the RHR heat exchangers to safely limit the long-term, post LOCA suppression pool heatup transient is evaluated on the basis that the makeup system is activated early in the transient. Specifically, the evaluation assumes that the heat exchangers are activated one-half hour after the LOCA and that at about this time the drawdown makeup system water has been added to the main suppression pool inventory. The makeup 30-minute timer will ensure that this condition will exist. The 3.75 minute dump period (8 minutes if only one line is operative) is not significant compared to the several

hours it takes for the suppression pool peak temperature to be reached.

An inadvertent dump of the upper pool during any period of plant operation with a pressurized vessel does not represent, in and of itself, any hazard to the public, the plant operating personnel or any plant equipment. The drywell weir wall has sufficient freeboard height between the suppression pool surface and the top of the weir wall to store the entire upper pool makeup volume on top of the normal suppression pool high water level without flooding over the weir wall into the drywell. The only concern is for the extremely low probability that a LOCA might occur during this period of high vent submergence following inadvertent dump. The dumped upper pool makeup volume can be transferred back to the upper pool through the RHR pumps with a 13 min pumping time, operating at maximum flow, thus restoring the initial suppression pool water level.

2.2 System Operation

The level channels continuously monitor the level of the suppression pool and annunciate in the control room both a high water level and a low water level condition. In addition, a low-low water level will both annunciate in the control room and initiate the suppression pool makeup flow. Low water level will be 6 inches below high water level and low-low water level will be 18 inches below low water level for a total difference of 24 inches between high water level and low-low water level. Each of the two level sensors dedicated to each dump line can initiate opening of both valves in the line. Automatic or manual actuation of the SPMS is inhibited without the

presence of a coincident LOCA signal. In the event that the low-low water level signal is not generated, the SPMS is actuated by the 30 minute timer. The timer is started by the LOCA signal which initiates actuation of the emergency core cooling pumps.

3.0 PEACH BOTTOM SPMS DESCRIPTION

Peach Bottom does not have an equivalent to a SPMS.

4.0 GRAND GULF SYSTEM EVALUATION

4.1 Event Tree Interrelationships

The FSAR analysis of the capability of the RHR heat exchangers to safely limit the long-term, post-LOCA suppression pool heatup transient is evaluated on the basis that the SPMS is activated early in the transient. For this reason, the SPMS contributes to Event I (RHRS) for both large and small LOCAs. Failure of the SPMS to transfer the upper containment pool water to the main suppression pool inventory after a LOCA results in suppression pool heatup eventually causing a containment failure.

4.2 SPMS Model Description

4.2.1 SPMS Boolean Equation

One Boolean equation of the SPMS was developed and used in the large and small LOCA analyses. This equation describes failure of both SPMS lines to operate and includes hardware, test, maintenance, and common mode contributions. This equation is:

SPMS = (SA + SAACC + LLOP*EPS1)*(SB + SBACC + LLOP*EPS2).

Table B11-1 relates each term of the previous above to the components shown in Figure B11-1. Table B11-2 describes the components identified in Table B11-1 and lists the failures that

contribute to the component unavailability. Table B11-3 gives a quantitative ranking of the different Boolean terms.

The SPMS valves are periodically manually tested, one at a time, during unit power operation. Manual testing of a valve is inhibited by interlock unless the other valve in series on the same line is closed. This test is intended to verify that valve will open and close. The SPMS instrumentation is also periodically tested and inspected.

Each of the two circuit channels is tested separately each month and the test time for each is approximately 10 minutes. Therefore,

$$Q_{circuit\ test} \simeq (\text{test frequency}) \times (\text{channel unavailability})$$

$$= \frac{1}{720\ \text{hours}} \times 0.167\ \text{hour} = 2.3 \times 10^{-4} \quad .$$

The maintenance of the two motor operated dump valves constitutes the maintenance contribution to SPMS failure. Typical mean outage time for motor operated valves is $\bar{t}$ = 19 hours. The average maintenance interval used in the Reactor Safety Study is 4.5 months which corresponds to a frequency of .22 maintenance acts per month. The unavailability due to maintenance for each valve in each dump line is therefore:

$$Q_{MOVs} = \frac{19}{720} \times .22 = 5.8 \times 10^{-3} \quad .$$

No common mode failures were identified as significant contributors to the SPMS unavailability.

4.2.2 SPMS Unavailability

Using the Boolean equation given in the last section and the term unavailabilities given in Table B11-1, an independent SPMS point estimate unavailability can be calculated. This was found to be:

$$SPMS = 1.0 \times 10^{-4} \quad .$$

Double maintenance contributions were removed from these unavailabilities. For example, simultaneous maintenance of valves in both SPMS dump lines were removed from the probability calculations.

The dominant failure contributors can be identified in Table B11-3. It shows that double hardware and hardware/maintenance failures of the two SPMS dump lines make up about 33% of the total point estimate unavailability.

The reader should be cautioned that these are unavailabilities for Grand Gulf's SPMS if the system is considered independent of all others. In general, failure of the SPMS will depend on what other systems have succeeded or failed (i.e., conditional probabilities must be used for the SPMS in the accident sequence analysis).

*Table B11-1. Boolean Equation Term Definition

Boolean Term	Term Definition	Term Unavailability
SA	FOO1A-A + FOO2A-A	1.4×10^{-2}
SB	FOO1B-B + FOO2B-B	1.4×10^{-2}
SAACC	Actuation and Control Circuit A	1.2×10^{-3}
SBACC	Actuation and Control Circuit B	1.2×10^{-3}
LLOP	LOCA induced loss of offsite power	1.0×10^{-3}
**EPS1	Emergency AC Power Division 1	6.7×10^{-2}
**EPS2	Emergency AC Power Division 2	6.7×10^{-2}

*Refer to Figure B11-1.
**Refer to Appendix B2.

Table B11-2. Component Unavailabilities

Component Description	Fault Identifier	Failure Contributors	Q/Components
Motor Operated Valve (Normally closed)	FOO1A-A	Control Circuit	3×10^{-4}
	FOO2A-A	Hardware	1×10^{-3}
	FOO1B-B	Plugged	1×10^{-4}
	FOO2B-B	Maintenance	5.8×10^{-3}
		Q Total	7.2×10^{-3}
Actuation and Control Circuitry	SAACC	Failure on demand	1×10^{-3}
	SBACC	Testing	2.3×10^{-4}
		Q Total	1.2×10^{-3}

Table B11-3. Quantitative Ranking of Boolean Equation Terms

SA*SB	6.1×10^{-5}
SA*SBACC	1.7×10^{-5}
SB*SAACC	1.7×10^{-5}
LLOP*EPS1*EPS2	4.5×10^{-6}
SAACC*SBACC	1.4×10^{-6}
SA*LLOP*EPS2	9.4×10^{-7}
SB*LLOP*EPS1	9.4×10^{-7}
SAACC*LLOP*EPS2	8.0×10^{-8}
SBACC*LLOP*EPS1	8.0×10^{-8}
	1.0×10^{-4}

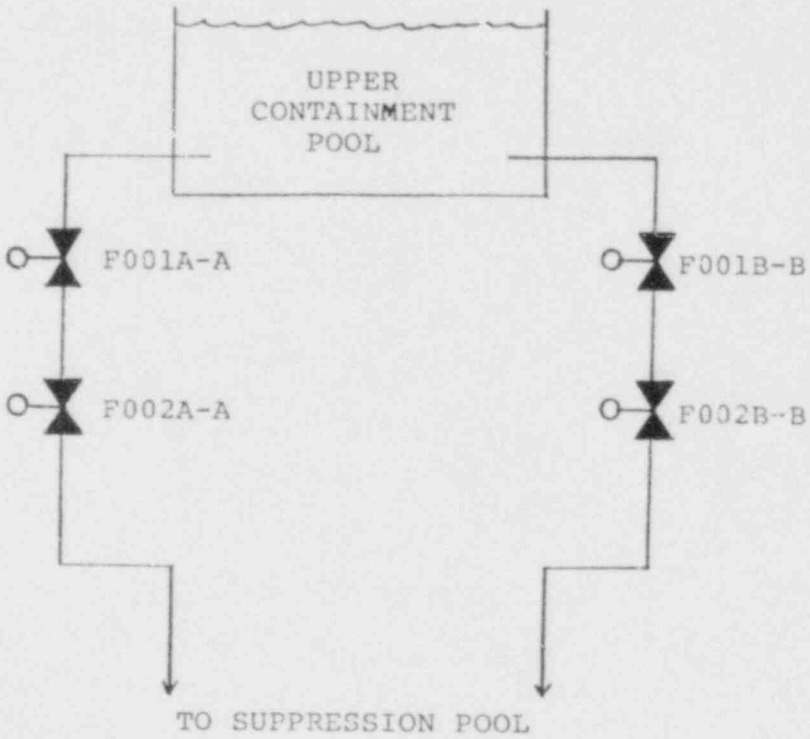

Figure B11-1. Grand Gulf Suppression Pool Makeup System

APPENDIX B12

SURVEY AND ANALYSIS

STANDBY SERVICE WATER SYSTEM (SSWS) - GRAND GULF PLANT

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1.0 INTRODUCTION

The Grand Gulf Standby Service Water System (SSWS) was reviewed and compared with another BWR design (Peach Bottom) evaluated in the WASH-1400 study. The SSWS designs for Grand Gulf and Peach Bottom are described in Sections 2 and 3 of this report respectively. A comparison of the two service water systems is given in Section 4. SSWS event tree interrelationships are detailed in Section 5. Also included in Section 5 is a description of the model used to incorporate SSWS failures into the Grand Gulf accident sequences and a point estimate of the SSWS unavailability assuming independence from all other Grand Gulf systems.

2.0 GRAND GULF SSWS DESCRIPTION

2.1 System Description

The Grand Gulf SSWS, which includes dedicated cooling towers is designed to remove heat from plant auxiliaries that are required for safe reactor shutdown. The SSWS provides cooling for plant components, as required, during normal shutdown and reactor isolation modes.

The SSW system consists of redundant trains comprised of cooling towers, pumps, piping, valves, and associated instrumentation as shown in Figure B12-1. Cooling water for each unit is pumped from the cooling tower basins by two redundant SSW pumps and one HPCS service water pump to the essential components through the two main redundant SSW supply headers (loops A and B) and the HPCS service water supply header (loop C). After removing heat from the components,

the coolant is piped back to the cooling towers where the heat is rejected through direct contact with ambient air.

The Standby Service Water System feeds each component given in Table B12-1 through branches from the associated main supply headers and the HPCS service water supply header.

Because the SSW system operates only during reactor shutdown, reactor isolation, and post-LOCA, the control room air conditioning units and the ESF electrical switchgear room coolers are also connected to the plant service water (PSW) system for cooling during normal plant operation. The fuel pool heat exchangers are connected to the component cooling water (CCW) system for cooling during normal plant operation. The remaining SSW system components are isolated from the PSW and CCW systems. These components are maintained full of water via the SSW fill tank during normal plant operation. The SSW system provides cooling to the component cooling water heat exchangers, instrument air compressors, and the drywell coolers only during a loss of offsite power and shutdown of a unit. Redundant automatic isolation valves are provided to separate non-essential cooling water systems from the SSW system.

The two SSW pumps (per unit), or either of the two SSW pumps in conjunction with the HPCS service water pump (one per unit), are sized to provide enough cooling water to safely shut down a unit following a LOCA. The discharge lines of the two SSW pumps associated with each tower are intertied via the basin recirculation line to permit additional flexibility of operation. No credit, however, was given in the analysis for the train interties. In addition, a line interconnecting the discharge of each SSW pump within a basin

permits transfer of SSW basin water from one basin to the other. An intertie with the RHR system is provided from Loop B of the SSW system supply header. The intertie contains two remote manually operated isolation valves that can be opened from the control room, thereby permitting containment and drywell flooding.

2.2 System Operation

The SSWS operates only during testing, reactor shutdown, and reactor isolation. System operation following a LOCA or other faulted condition is initiated automatically and requires no operator action (See Table B12-2). Initiation of SSWS operation for normal shutdown is accomplished manually from the control room.

If a LOCA occurs, all cooling tower fans, SSW pumps, and HPCS service water pumps will start. If a loss of offsite power occurs during a LOCA, the pumps and fans will stop and then will automatically resume operation after transfer to standby diesel generator power is completed. At the same time, the plant service water lines to the SSW components that are required during normal operation are automatically isolated and the SSWS lines are opened to these components.

The SSW system is operated at a lower pressure than the RHR system for all modes of SSW system operation. The cooling water return line to each RHR heat exchanger is monitored by a radiation sensor to detect any radioactive contamination resulting from a tube leak. When contamination is detected, an alarm sounds in the control room at which time the operator isolates the faulted heat exchanger via motor operated isolation valves. These valves can also be manually actuated locally.

The SSWS includes local temperature and pressure test points for evaluating performance of the system coolers. Local indicators permit determination of the pump discharge pressures. Discharge flow from each of the SSW pumps and return flow to the SSW cooling towers is measured and compared. A high differential between the measured flows indicates system leakage and is annunciated in the control room. Sumps and pumps, located throughout the plant, serve to detect system leakage. Excessive leakage to a particular sump is indicated by a high-high level alarm and operation of the sump pump. Should a large break occur in a SSW pipeline located outside of the plant buildings, a low-pressure switch in the associated SSW pump discharge header is annunciated in the control room. A small break is detected by a higher than normal level drop in the SSW cooling tower basins which include level sensors for monitoring basin water level.

3.0 PEACH BOTTOM SSWS DESCRIPTION

The Standby Service Water System at Peach Bottom is actually composed of two systems: the High Pressure Service Water System (HPSWS) and the Emergency Service Water System (ESWS).

Following a loss-of-coolant accident, heat stored in the reactor coolant system and subsequent heat picked up by emergency coolant are deposited in the primary containment wetwell. The HPSWS, in conjunction with the Low Pressure Core Recirculation System, is used to transfer the long term accumulation of heat in the wetwell to an external heat sink. The HPSWS can also be used alone as a last resort to inject reservoir (river) water directly

into the reactor vessel, thereby flooding the reactor and containment.

The HPSWS is comprised of the pumps, valves, heat exchangers, cooling towers and piping arranged as shown in the simplified flow diagram, Figure B12-2. Under anticipated LOCA conditions water will be pumped by one or more of the four pumps (each with a capacity of 4500 gpm) from the Unit 2 pump basin, through the tube side of the LPCRS heat exchangers, and to the discharge pond, thus removing heat from the emergency coolant which is circulated through the shell side of the heat exchangers by the LPCRS.

The emergency service water system (ESWS) is shown in the simplified flow diagram of Figure B12-3. The function of the ESWS is to:

a. Provide a backup supply of cooling water to the LPCRS and CSRS pump compartment unit coolers and the CSRS pump lube oil coolers, and

b. Provide cooling water to the diesel generators.

The ESWS and the "normal service water system" supply cooling water, via check valves and a common manifold, to the pump compartment unit coolers. Either water supply will suffice for pump compartment cooling. The ESWS is a standby system which supplies the needed cooling water upon loss of normal service water (e.g., if off-site power is lost). Water for both systems is normally taken from a reservoir adjacent to the plant and discharged back into the reservoir. If for some reason water is not available from the

normal source, water can be taken by the ESWS from an on-site emergency cooling tower reservoir (3.7 million gallons). In this case, water is recirculated through the loads, through the cooling towers via the booster pumps, and back to the emergency reservoir.

The ESWS has two major operational modes, i.e., non-recirculation and recirculation. The system as shown in Figure B12-3 is aligned for the normal or non-recirculating mode. By opening valve MO 841 and closing valve MO 498 the system is realigned for emergency recirculation. Closure of the sluice gates MO 2233A, MO 2233B, and MO 2209B will automatically close valve MO 498. The starting of emergency cooling water pump 186 and insufficient output pressure from emergency service water pumps P57A and P57B will automatically open MO 841.

When any one of the four diesels attains a speed of 250 rpm or when LOCA conditions exist (indicated by low reactor water level or high drywell pressure), pumps P57A, P57B, and P186 will be automatically started. Pump 186 (emergency cooling water pump) is tripped off automatically 23 seconds after start given that the water pressure provided by pumps 57A and 57B is adequate. Either pump P57A or P57B can be manually turned off if sufficient output pressure is being maintained by one pump. The pump that has been manually shut off will automatically restart if the operating pump (P57A or P57B) fails to maintain sufficient output pressure.

For recirculation, the two booster pumps start automatically when valve MO 498 closes. If no water is available at the pump suction, the pumps will trip off. The cooling tower fans must be started manually by switches located in the control room. Cooled

water from the cooling tower may be returned to the pump basin by gravity flow. The line has pneumatically operated modulating valves that sense basin water level when in the recirculation mode (sluice gates closed) and regulate water level accordingly.

4.0 COMPARISON OF GRAND GULF AND PEACH BOTTOM SSWS

The Peach Bottom Service Water System is composed of the HPSWS and ESWS. Both Grand Gulf SSWS and Peach Bottom ESWS are designed to supply cooling to the safeguard room coolers and the diesel generator coolers of their respective plants during emergency conditions. Each system supplies cooling water to its room coolers from emergency basins via redundant service water pump trains. After removing heat from the components, the coolant is piped back to the cooling towers where the heat is rejected to the atmosphere. In addition to its two redundant SSW trains, the Grand Gulf SSWS incorporates a HPCS service water train. The SSWS supplies cooling to the RHR heat exchangers in emergency conditions. In Peach Bottom, during an accident, the HPSWS supplies cooling to the RHR heat exchangers.

The Peach Bottom system is shared by both of its units, whereas each unit of Grand Gulf has its own SSWS.

Unavailability of the HPSWS at Peach Bottom is dominated by test and maintenance contributions of the valves and pumps and by a common mode failure of the HPSWS where the operator fails to override some trip relays to manually start the HPSWS.

Unavailability of the ESWS at Peach Bottom is dominated by potential faults in the single output valve, V506 (Refer to Figure

B12-3). Any plugging of this valve will prevent coolant flow through all unit coolers. Also, a possible failure mode considered was the possibility that this normally keylocked open valve was closed for a maintenance of test act and inadvertently left in a closed position. The unavailability of the ESWS and HPSWS was estimated in the RSS to be

$$Q(ESWS) = 1.2 \times 10^{-4}$$

and

$$Q(HPSWS) = 4.3 \times 10^{-4} \text{ (no recovery in 1/2 hour)} \quad .$$

Unavailability of Grand Gulf's SSWS was also dominated by maintenance contributions of the pumps and valves in each loop. No common mode failures were identified, however. SSWS loop unavailability is calculated in Section 5.2.2 and was found to be approximately 10^{-2}. If failure of two out of three SSWS loops is defined as system failure, then SSWS unavailability would be about 10^{-4}, close to the RSS value.

5.0 GRAND GULF SYSTEM EVALUATION

5.1 Event Tree Interrelationships

The principal function of the Standby Service Water System is to provide cooling water to the various coolers and heat exchangers necessary during accidents.

Because it is a support system of the RHRS, the Standby Service Water System unavailability is considered in estimating the probability

of occurrence of Event I on the LOCA event tree and Event W on the transient event tree. The SSWS is also incorporated into the model of the Emergency AC Power System (EPS). Refer to Appendix B2.

Failure of a Standby Service Water loop (A, B, or C) is defined as failure to circulate cooling water to essential components of the plant.

5.2 SSWS Model Description

5.2.1 SSWS Boolean Equations

The components modeled are the pump and main valves of each SSWS loop. Standby Service Water valves which isolate specific ESF components were treated as part of the particular system served by the component. For example, failures of the inlet and outlet SSWS valves for the diesel jacket water coolers were included in the analysis of the Emergency AC Power System. If either of these valves fail, water will not flow through the jacket coolers and the diesel generator will trip due to overheating. This will cause a loss of the associated EPS division, but not the associated SSWS loop.

Three equations of each SSWS loop were developed; one for LOCA's, one for T_{23} sequences, and one for T_1 sequences. The LOCA equations differ from the others in that they include failure caused by loss of emergency power after a LOCA induced loss of offsite power. The T_1 equations include the possibility that offsite power is not recovered and emergency power is unavailable. In T_{23} sequences, AC power is assumed to be available. These equations are:

For LOCAs

SSWA (Loop A) = SSA + SAC + LLOP*EPS1 ,

SSWB (Loop B) = SSB + SBC + LLOP*EPS2 ,

SSWC (Loop C) = SSC + SCC + LLOP*EPS3 .

For T_1 Transients

SSWA = SSA + SAC + LOPNRE*LOPNRL*EPS1 ,

SSWB = SSB + SBC + LOPNRE*LOPNRL*EPS2 ,

SSWC = SSC + SCC + LOPNRE*LOPNRL*EPS3 .

For T_{23} Transients

SSWA = SSA + SAC ,

SSWB = SSB + SBC ,

SSWC = SSC + SCC .

Table B12-3 relates each of the above terms with the components shown in Figure B12-1. Table B12-4 lists total component unavailability and contributors to the component unavailability. These unavailabilities include hardware, maintenance, and human faults when applicable.

While unavailability due to testing of the SSWS components was found to be negligible due to a test override capability, a test unavailability of 2.3×10^{-4} was estimated for downtime due to SSWS logic circuit testing for each loop. This number was obtained by assuming a biannual, 1 hour test of SSWS initiating circuits.

Loop unavailability due to maintenance is from the pump and motor operated valves. The average maintenance interval used in the Reactor Safety Study is 4.5 months, which corresponds to a

frequency of .22 per month. The unavailability of a component due to maintenance is estimated to be

$$Q_{maintenance} = \frac{\bar{t}(.22)}{720}$$

where $\bar{t}$ is the mean maintenance duration. Using a $\bar{t}$ of 19 hours for pumps and valves we find

$$Q_{MOV \text{ and pump maintenance}} = 5.8 \times 10^{-3} \quad .$$

The only human error significantly contributing to the SSWS failure probability is the inadvertent closure during maintenance of several normally open manual valves. If manual valves F199A and F199B are closed, SSWS loops A and B will fail due to inadequate pump lubricating oil cooling. If manual valve F013 is closed, loop C will fail.

For a normally open manual valve that is closed during maintenance, the steady state probability that it will be found closed during a given month (unavailability) was estimated in the RSS by the conditional probability

$$Q = p(\text{undetected/left closed}) \cdot p(\text{left closed/maint.}) \cdot p(\text{maint.})$$

where, p(undetected/left closed) = 1/3, is the estimated probability that the valve misalignment is not detected during walk-around plant inspections, p(left closed/maint.) = 10^{-2} is the basic human error of leaving the valve closed, and p(maint.) = 0.22 is the probability that maintenance took place the previous month, given a mean maintenance interval of 4.5 months. Therefore,

Q(F199A, F199B inadvertently closed)

$$= (.33)(.01)(.22) = 7.3 \times 10^{-4} \quad .$$

Manually valve F013 is normally locked open and therefore is less susceptible to be left in the wrong position. The unavailability given in the RSS for this type of valve failure is 1×10^{-4}. Therefore,

$$Q(\text{F013 inadvertently closed}) = 1.0 \times 10^{-4} \quad .$$

No common mode failures of the SSWS redundant trains contributed significantly to the SSWS unavailability.

5.2.2 SSWS Unavailability

Using the Boolean equations given in the last section and the term unavailabilities given in Table B12-1, an independent point estimate unavailability can be calculated for each SSWS loop. These are found to be:

For LOCAs

SSWA = 2.2×10^{-2}

SSWB = 2.2×10^{-2}

SSWC = 1.5×10^{-2}

For T_1 Transients

SSWA = 2.3×10^{-2}

SSWB = 2.3×10^{-2}

SSWC = 1.6×10^{-2}

For T_{23} Transients

SSWA = 2.2×10^{-2}

SSWB = 2.2×10^{-2}

SSWC = 1.5×10^{-2}

A quantitative ranking of the Boolean terms is given in Table B12-5. It is evident from this table that the terms SSA, SSB and SSC dominate the three loop equations. These terms represent the combined hardware and maintenance unavailability contributions for components in each individual SSWS loop. The analysis indicates that component maintenance makes up approximately 79 percent of the total SSWS loop unavailability.

The reader should be cautioned that these are unavailabilities for Grand Gulf's SSWS if the system is considered independent of all others. In general, SSWS unavailability will depend on what other system successes or failure have occurred, i.e., the unavailabilities used for the SSWS in the sequences analysis must be conditional unavailabilities.

Table B12-1. Standby Service Water System Loads

Loop A

		DESIGN DUTY ($\times 10^6$ BTU/H)
a.	RHR heat exchanger A	184.7
b.	Standby diesel generator A jacket water cooler	23.75
c.	RHR pump A seal cooler	0.30
d.	RHR A room cooler	0.54
e.	LPCS room cooler	0.30
f.	Fuel pool heat exchanger A	7.45
g.	RCIC room cooler	0.05
h.	Control room A/C unit A	0.966
i.	ESF electrical switchgear room coolers	0.329
j.	Drywell purge compressor A	0.875
k.	SSW pump A motor cooler	0.03
l.	SSW pump A work	2.039

Loop B

a.	RHR heat exchanger B	184.7
b.	Standby diesel generator B jacket water cooler	23.75
c.	RHR pump B seal cooler	0.30
d.	RHR pump C seal cooler	0.30
e.	RHR B room cooler	0.54
f.	RHR C room cooler	0.34
g.	Fuel pool heat exchanger B	7.45
h.	Control room A/C unit B	0.966
i.	Drywell coolers	5.40
j.	Component cooling water heat exchangers	4.70
k.	Instrument air compressors	1.75
l.	Drywell purge compressor B	0.875
m.	ESF electrical switchgear room coolers	0.329
n.	SSW pump B motor cooler	0.03
o.	SSW pump B work	2.039

Loop C

a.	HPCS diesel generator jacket water coolers	10.89
b.	HPCS room cooler	0.528
c.	HPCS service water pump work	0.255

Table 12-2. Standby Service Water System Initiating Signals

SSW Train A Initiation Logic

RHR Pump A running
LPCS Pump running
RCIC Turbine Steam Supply Valve open
Diesel Generator No. 11 running
LOCA (reactor low water level or drywell high pressure)
Manual (control room handswitches)

SSW Train B Initiation Logic

RHR Pump B running
RHR Pump C running
Diesel Generator No. 12 running
LOCA (reactor low water level or drywell high pressure)
Manual (control room handswitches)

SSW Train C Initiation Logic

HPCS System initiates
HPCS Pump running
HPCS Diesel Generator running
Manual (control room handswitch)

*Table B12-3. Boolean Equation Term Descriptions

Boolean Term	Term Definition	Term Unavailability
SSA	C001A-A + F008A + F001A-A + F005A-A + F199A	2.1×10^{-2}
SSB	C001B-B + F008B + F001B-B + F005B-B + F199B	2.1×10^{-2}
SSC	C002-C + F012 + F013 + F011-C	1.4×10^{-2}
SAC	Actuation and Control Circuit Loop A	1.2×10^{-3}
SBC	Actuation and Control Circuit Loop B	1.2×10^{-3}
SCC	Actuation and Control Circuit Loop C	1.2×10^{-3}
LLOP	LOCA induced loss of offsite power	1.0×10^{-3}
LOPNRE	Failure to recover offsite power in 30 minutes	2.0×10^{-1}
LOPNRL	Failure to recover offsite power within 30 hours given LOPNRE	1.0×10^{-1}
**EPS1	Emergency Power Division 1	4.5×10^{-2}
**EPS2	Emergency Power Division 2	4.5×10^{-2}
**EPS3	Emergency Power Division 3	4.0×10^{-2}

*Refer to Figure B12-1.

**Refer to Appendix B2. SSWS contributions to EPS division failure have been removed.

Table B12-4. Component Unavailabilities

Component Description	Fault Identifiers	Failure Contributors	Q/Components
Check Valve	F012 F008A F008B	Hardware	1.0×10^{-4}
		Q Total	1.0×10^{-4}
Manual Valve (Locked Open)	F013	Operator Error	1.0×10^{-4}
		Plugged	1.0×10^{-4}
		Q Total	2.0×10^{-4}
Manual Valve (Normally Open)	F199A F199B	Operator Error	7.3×10^{-4}
		Plugged	1.0×10^{-4}
		Q Total	8.3×10^{-4}
Motor Operated Valve (Normally Open)	F011-C F001A-A F001B-B F005A-A F005B-B	Maintenance	5.8×10^{-3}
		Plugged	1.0×10^{-4}
		Q Total	5.9×10^{-3}
Standby Service Water Pump	C001A-A C001B-B C002-C	Hardware	1.0×10^{-3}
		Control Circuit	1.0×10^{-3}
		Maintenance	5.8×10^{-3}
		Q Total	7.8×10^{-3}
Actuation and Control Circuitry	SAC SBC SCC	Failure on Demand	1.0×10^{-3}
		Testing	2.3×10^{-4}
		Q Total	1.2×10^{-3}

Table B12-5. Quantitative Ranking of Boolean Terms

For LOCAs:

SSWA	SSA	2.1×10^{-2}
	SAC	1.2×10^{-3}
	LLOP*EPS1	4.5×10^{-5}
		2.2×10^{-2}
SSWB	SSB	2.1×10^{-3}
	SBC	1.2×10^{-3}
	LLOP*EPS2	4.5×10^{-5}
		2.2×10^{-2}
SSWC	SSC	1.4×10^{-2}
	SCC	1.2×10^{-3}
	LLOP*EPS3	4.0×10^{-5}
		1.5×10^{-2}

For T_1 Transients:

SSWA	SSA	2.1×10^{-2}
	SAC	1.2×10^{-3}
LOPNRE*LOPNRL*EPS1		9.0×10^{-4}
		2.3×10^{-2}
SSWB	SSB	2.1×10^{-2}
	SBC	1.2×10^{-3}
LOPNRE*LOPNRL*EPS2		9.0×10^{-4}
		2.3×10^{-2}
SSWC	SSC	1.4×10^{-2}
	SSC	1.2×10^{-3}
LOPNRE*LOPNRL*EPS3		8.0×10^{-4}
		1.6×10^{-2}

For T_{23} Transients:

SSWA	SSA	2.1×10^{-2}
	SAC	1.2×10^{-3}
		2.2×10^{-2}
SSWB	SSB	2.1×10^{-2}
	SBC	1.2×10^{-2}
		2.2×10^{-2}
SSWC	SSC	1.4×10^{-2}
	SCC	1.2×10^{-3}
		1.5×10^{-2}

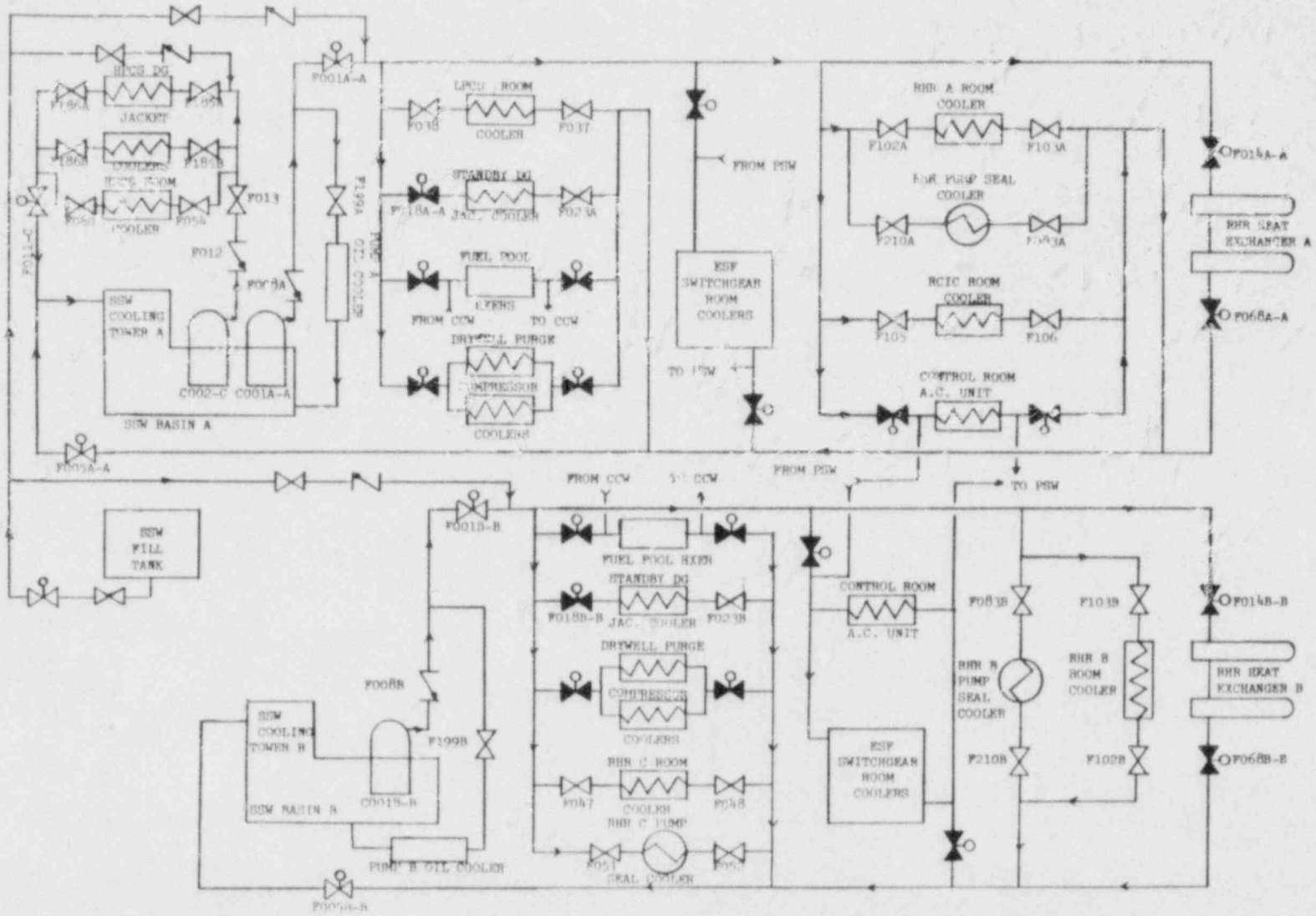

Figure B12-1. Grand Gulf Standby Service Water System

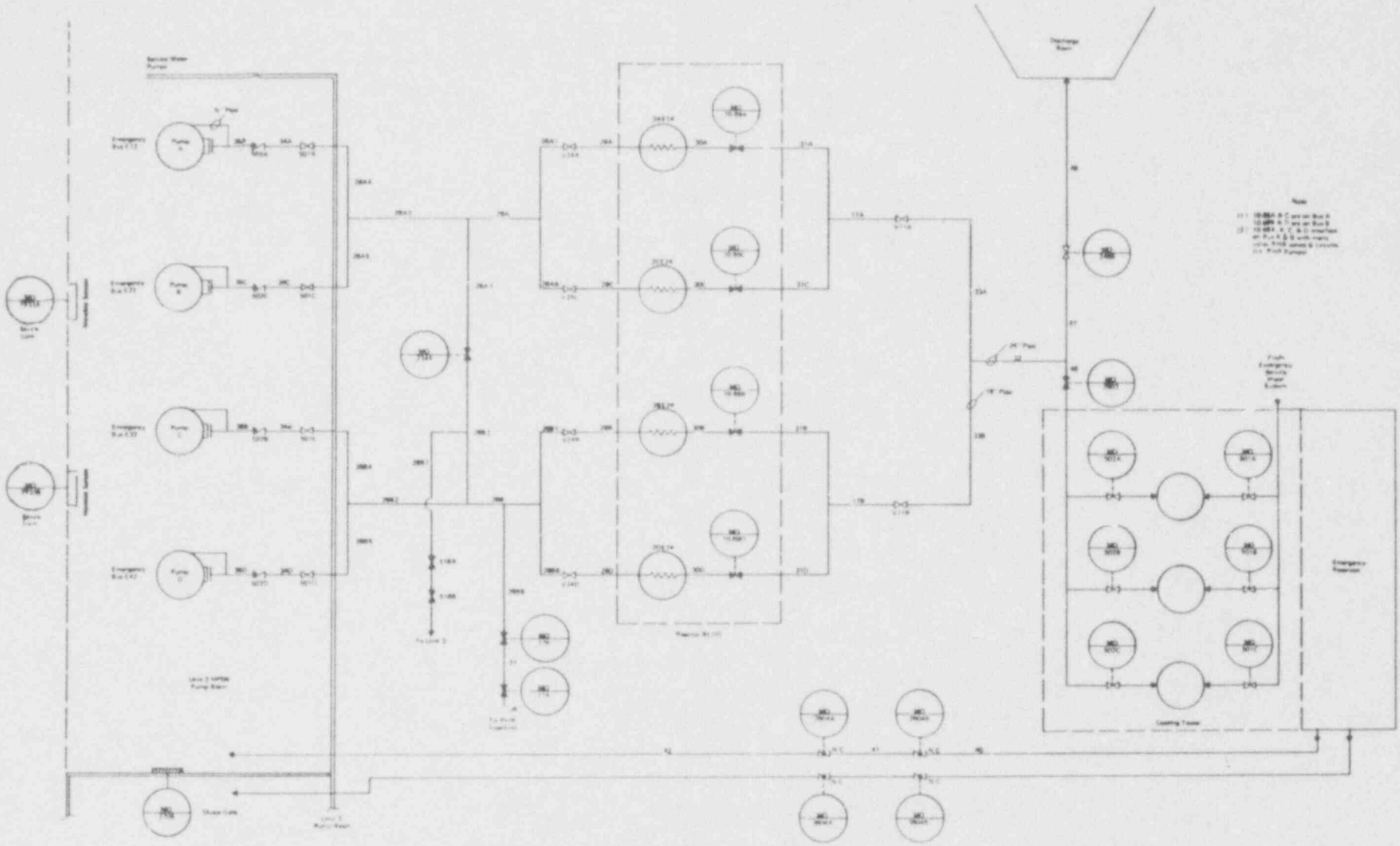

Figure B12-2. Peach Bottom HPSWS Simplified Flow Diagram

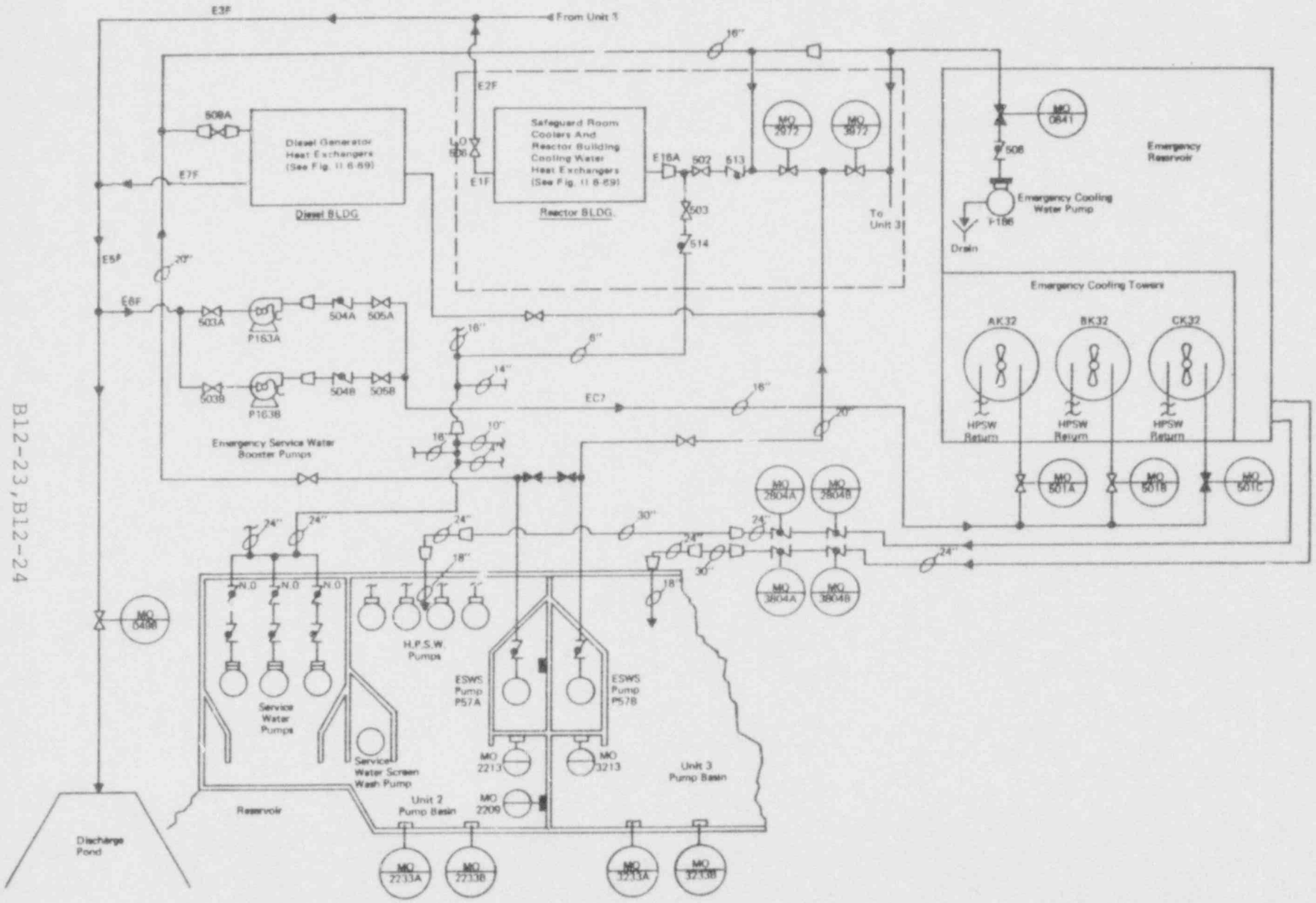

Figure B12-3. Peach Bottom ESWS

APPENDIX C

MARCH ANALYSES FOR THE DOMINANT

GRAND GULF ACCIDENT SEQUENCES

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1.0 INTRODUCTION

The dominant accident sequences for the Grand Gulf plant can be divided into the following categories: (1) loss of heat sink for dissipation of the fission product decay heat, (2) failure to provide coolant makeup to the reactor vessel following a transient or LOCA, and (3) failure to properly terminate the fission process after receiving a scram signal. MARCH analyses were performed to describe the accident progression for one or more of the sequences in each of these categories.

2.0 LOSS OF CONTAINMENT HEAT SINK

The sequences in this category include TPQI, TQW, and (S,A)I. As a consequence of the loss of the containment heat sink, elevated containment pressures and suppression pool temperatures result. The elevated suppression pool temperatures and containment pressures may lead to eventual failure of the ECC pumps. The possibility of recovery is included in the derivation of the sequence probabilities. Failure of the ECC pumps results in core uncovery and meltdown. ECC pump failure for these cases may occur in several ways: (1) due to prolonged operation above design temperatures, (2) by pump cavitation following containment failure, or (3) by depletion of the ECC coolant supply. Many of the sequences in this category were analyzed for more than one of the above cases. However, the case where the ECCS pumps fail after containment failure due to cavitation was assumed in the results given in Chapter 6.

After about 17 hours for the TQW sequence, the suppression pool temperature will exceed the 212°F design temperature for the ECC pumps. Prolonged pump operation in excess of design

conditions cannot be assured. However, if the ECC pumps continue to work, the containment pressure will continuously increase. The nominal containment failure pressure of 45 psia is reached in about 30 hours. At 30 hours, the suppression pool temperature is about 256°F. When containment failure occurs, suppression pool flashing would be expected to cause pump cavitation and failure. The containment failure may also produce structural damage which could cause ECC failure. If the ECC pumps do not fail when the containment fails, the pumps could conceivably operate until a significant fraction of the suppression pool is depleted. MARCH calculations indicate an additional several days would be required to vaporize the suppression pool assuming no replenishment.

The accident consequences are dependent on the timing of the assumed ECC pump failure in these loss-of-heat sink cases. If ECC pump failure does not occur until after containment failure, core meltdown occurs in a failed containment. No scrubbing of fission products by the suppression pool can be assured in this case, and large escape of fission products to the atmosphere is predicted. However, if early ECC pump failure is assumed (due to excessive pool temperature), core meltdown occurs in an initially intact containment and some fission product scrubbing and plateout may take place. MARCH predicts containment failure by the time of head failure, however, so that fission products released during the subsequent concrete penetration phase are released into a failed containment. CORRAL calculations predict BWR Category 2 releases for the case of delayed con-

tainment (and ECC) failure and BWR 3 releases for the case of early ECC failure and meltdown in an initially intact containment.

Figures C-1 and C-2 are plots of the MARCH calculated pressures in the drywell (Volume 1) and wetwell or containment (Volume 2) for sequence TQW. The ECC pumps in this case were assumed to fail at the end of ECC injection from the Condensate Storage Tanks. When the pumps switch to the recirculation mode at 980 minutes, the suppression pool temperature is 209°F. It was assumed the pumps failed at this time due to high pool temperature. Core uncovery starts at 1186 minutes. Core melting starts at 1255 minutes, and is complete by 1326 minutes. Bottom head failure occurs 14 minutes later. The containment pressure peaks at 61 psia. In this particular MARCH calculation, containment failure was assumed not to occur, and the pressure remains at about 60 psia for about 4 hours. At about 1600 minutes the metallic layer in the core debris on the drywell floor becomes more dense than the oxide layer, and flips to the bottom. This is accompanied by an increased chemical reaction and release of hot non-condensible gases to the containment (Figure C-3) and an increase in the vertical concrete penetration rate (Figure C-4). For the calculation of the fission product releases, this MARCH calculation was repeated assuming containment failure at 45 psia. The phenomena after containment failure are similar to those discussed above, and the plotted results are not repeated here.

Additional MARCH calculations were performed for the TQW sequence assuming ECC pump operation until containment failure

and for the TPQI and AI sequences. In the analysis of the TPQI sequence, the Power Conversion System is assumed to be unavailable for removal of decay heat; with the Power Conversion System functioning the onset of core melting would be substantially delayed. The phenomenological considerations and accident timing are similar for these cases. Figure C-5 shows containment pressures for a TPQI sequence in which ECC pump failure is assumed at the start of the recirculation mode, and containment failure occurs at 45 psia. The primary system pressure, coolant mixture level, and fractions core melted and cladding reacted are plotted in Figures C-6, C-7, and C-8.

3.0 COOLANT MAKEUP FAILURE

The dominant sequences in this category include TQUV, TPQE, and (S,A)E. These accidents involve failure to provide coolant makeup to the reactor vessel. Consequently, core uncovery and meltdown result. The accident timing depends on the coolant leak rate from the vessel, and thus on the type of transient or LOCA break size. For the TQUV transient, in which boiloff of the primary coolant would take place at an elevated pressure through a cycling safety valve, core melting starts at 106 minutes. If a safety valve sticks open, as in the TPQE sequence, core melting starts at 71 minutes. For a large LOCA, melting starts at 13 minutes.

The containment pressure histories following vessel head failure are somewhat different for the transient and LOCA initiated sequences. In the transients, the primary system is vented directly into the pressure suppression pool through the safety/relief

valve discharge headers. Thus, there is little or no condensation of water in the drywell. After head failure, the containment pressure is at relatively low levels but contains a large quantity of hydrogen. There are significant concentrations of hydrogen in both the drywell and wetwell (containment) atmospheres. If hydrogen burning takes place following vessel failure and includes burning in the large containment volume, there appears to be little question of containment failure. Burning in the containment could be initiated either by ignition sources there or through the propagation of burning from the drywell. In the latter, the core debris interaction with concrete appears to be a highly likely ignition source. In the absence of hydrogen burning, containment failure would occur several hours after vessel failure due to the buildup of noncondensables from the reaction of the core debris with concrete.

For LOCAs, the primary coolant is released directly to the drywell, with the possibility of water accumulation on the drywell floor and/or the bottom of the reactor cavity. MARCH analyses indicate that on the order of 250,000 lb of water could collect in the drywell for a sequence such as AE. The interaction of the core debris with this water will lead to rapid steam generation as well as additional hydrogen production. While much of the steam produced by the debris-water interaction will be quenched by the pool, the associated redistribution of noncondensables will raise the containment pressure to near the nominal failure level. Thus, there is a significant probability of containment failure shortly after vessel meltthrough even in the absence of

hydrogen burning. If the containment does not fail due to this pressure peak, failure would be predicted several hours later as a result of the continued buildup of noncondensables. As in the case of the transient sequences, there are significant concentrations of hydrogen in both the drywell and containment atmospheres at the time of vessel failure. In the event of hydrogen burning in the large containment, failure would be expected. Should the burning be limited to the drywell volume, a small overall pressure increase would be predicted.

The containment pressures obtained by hydrogen burning are based on MARCH calculations in which about 50 percent of the total core zircaloy is reacted during the in-vessel phase of core meltdown. For the Grand Gulf plant, the core zircaloy is approximately half in the fuel rod cladding with the remaining half primarily in the fuel bundle shrouds. Thus, the zircaloy reaction is equivalent to 100 percent cladding reaction, which is consistent with previous PWR studies. The remaining zircaloy may be oxidized during the concrete penetration phase of the accident.

The pressure suppression pool remains relatively cool in these sequences, even in the absence of RHRS operation, so that there is significant scrubbing of fission products by the pool prior to the time of containment failure. CORRAL calculations indicate BWR Category 3 releases from the containment if containment failure occurs after core meltdown but prior to the start of the concrete penetration phase of the accident. If containment failure is delayed several hours after head failure, BWR Category 4 releases are predicted.

Figures C-9, C-10, and C-11 show the primary system pressure, coolant mixture level, and the fractions core melted and cladding reacted for the TPQE sequence. Figure C-9 shows the primary system depressurization with a stuck open valve (flow area = 0.16 ft^2). Figure C-10 shows core uncovery starting at 32 minutes. From Figure C-11, core melting is shown to start at 71 minutes. Containment pressures in the drywell (Volume 1) and wetwell (Volume 2) are plotted in Figures C-12 and C-13. It was assumed that hydrogen burning did not occur in these calculations. Several hours are required after head failure (at 136 minutes) to reach the nominal failure pressure of 45 psia. Figure C-14 shows the adiabatic hydrogen burn pressures which would result from burning all the hydrogen in the compartments at the indicated times. Note that burning in the drywell would generally produce pressures that could probably be accommodated. The pressures associated with the wetwell (Volume 2) hydrogen burns are clearly well in excess of design. Compartment atmosphere temperatures are plotted in Figure C-15. The wetwell temperatures (Volume 2) follow the suppression pool temperature. The drywell temperature (Volume 1) after head failure is controlled by the hot gases coming from the core debris during the concrete penetration phase of the accident. Basepad melting is shown in Figure C-16.

In the calculations of accident probabilities for the TPQE sequence, the Systems Analysis Task assumed that ADS failure would preclude the possibility of using the low head ECC pumps. Figure C-9 indicates the primary system pressure would fall

below the low pressure core spray shutoff head (290 psig) at about 50 minutes with leakage only through the stuck-open valve. Hand calculations indicate that ECC injection equal to the steam leakage through the valve at pressures above 260 psia could accommodate the core decay heat. At 260 psia, the LPCS injection rate would approximately balance the boiloff rate. Thus, cooling by the LPCS may be possible for the TPQE sequence. At the time of possible LPCS injection, the core is nearly uncovered. Specific MARCH calculations were not performed to determine if core recovery could be accomplished in time to prevent core melting. The results would be sensitive to a number of modeling assumptions such as the assumed valve leak area. The results in Figure C-9 assume the valve fails in the full-open position. Lesser flow area could preclude LPCS injection.

Selected MARCH results for the TQUV and AE sequences are shown in Figures C-17 through C-32. The containment pressures for these MARCH calculations assume containment failure does not occur. The CORRAL results are based on an alternate set of MARCH calculations in which containment failure at 45 psia was assumed. No credit was taken in the CORRAL calculations for possible fission product scrubbing by the suppression pool after containment failure even though pool temperatures generally remain below 170°F. (See Figures C-24 and C-31.) This could be a possible overconservatism in the analysis. The uncertainties in the modes of containment failure, possible structural damage in the pool area, ejection of pool water during containment depressurization, or other means of vent uncovery could preclude effective fission product scrubbing.

4.0 REACTOR PROTECTION SYSTEM FAILURE

Failure of the reactor protection system will cause the core to remain at high power levels. For the BWR analyzed in the Reactor Safety Study (WASH-1400), the core power was considered to equilibrate at a 30 percent level in the absence of scram. This figure was derived from vendor ATWS calculations. The same power level was assumed for the present Grand Gulf MARCH calculations. The accident scenario in the absence of scram as described by MARCH is somewhat dependent on primary system break size, but the overall consequences are about the same for a number of sequences.

For small pipe break LOCAs and transients in the absence of ADS actuation, only the high head pumps are available for coolant makeup. The high head pumps do not have sufficient capacity to keep up with coolant boiloff at power levels substantially above decay levels. The rapid decrease of coolant inventory due to the elevated power level will lead to partial core uncovery and may lead to the start of core melting. Subsequent reduction in power will take place as a result of loss of moderator. If the initial melting is assumed to progress, core melting in an initially intact containment would be predicted. With the continued operation of the high pressure injection systems and the expected decrease in power level it is likely that effective cooling will be reestablished, then the core power will tend to approach a level where it is balanced by the heat removal capacity of the injection system. This quasiequilibrium power level will be higher than decay power and will exceed the capacity of the RHRS, thus leading to

suppression pool heatup. Continued suppression pool heatup will lead to increasing containment pressure and eventual failure. ECCS pump failure can be expected following containment failure or upon the switchover from the injection to the recirculation mode of operation. Since at the time of ECCS failure the core is already partially uncovered, core melting will follow shortly and take place within a failed containment. With the actuation of the ADS, the transient and small LOCA sequences with failure to scram will be similar to the corresponding large LOCA case.

For a large LOCA with failure to scram, the AC sequence, the low head pumps have sufficient capacity to compensate for coolant boiloff at 30 percent power level. However, suppression pool heatup and containment overpressurization occur because the RHRS decay heat removal system is inadequate to handle a 30 percent power level. The possible failure modes of the ECC pumps at high pool temperature or upon containment failure for the AC case are similar to those previously discussed for the TQW sequence. Core meltdown would follow failure of the ECC pumps. ECC failure due to containment depressurization would be predicted to result in BWR Category 2 releases. Loss of the ECC pumps prior to containment failure would result in Category 3 releases.

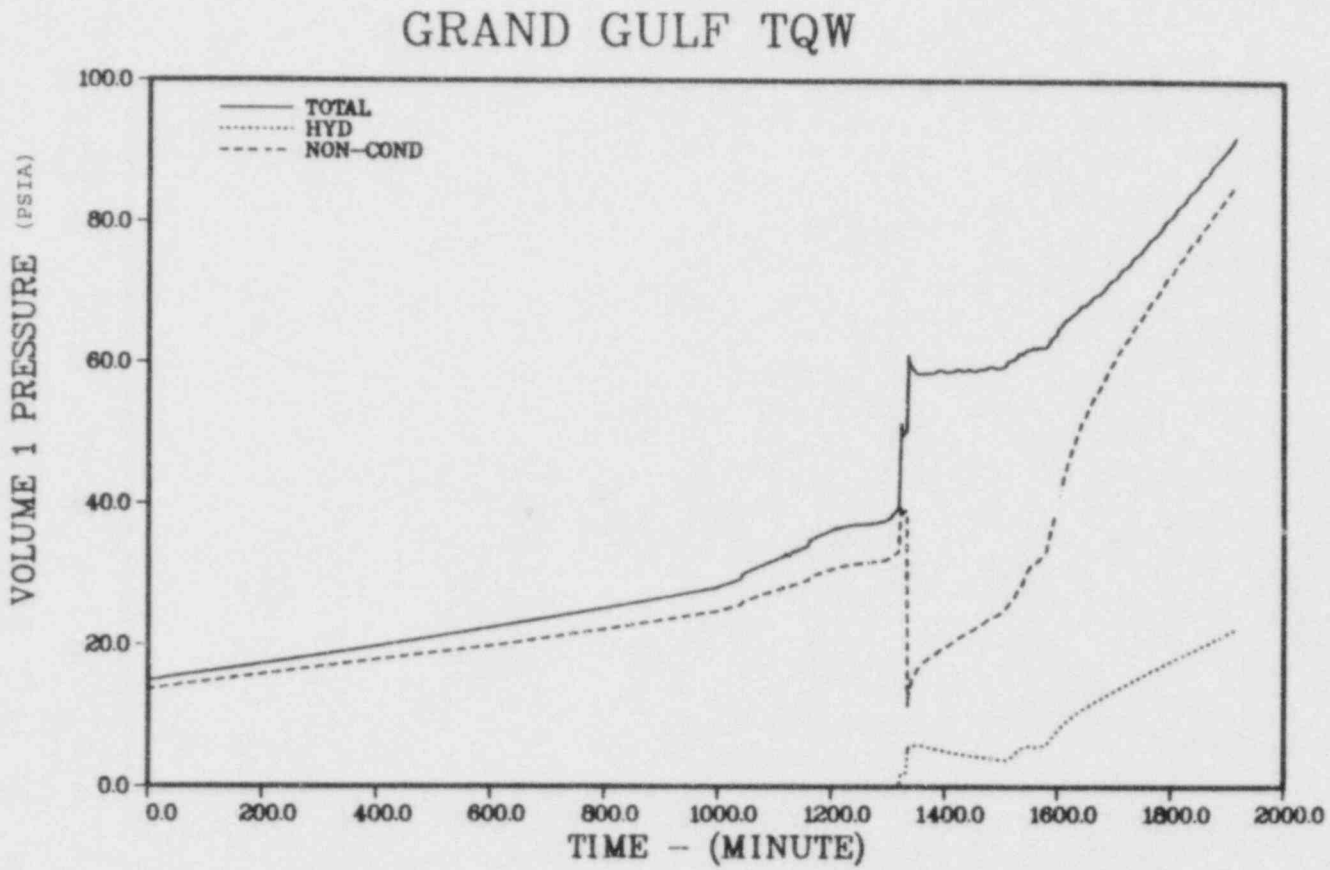

Figure C-1. Volume 1 Pressure Versus Time - TQW Sequence

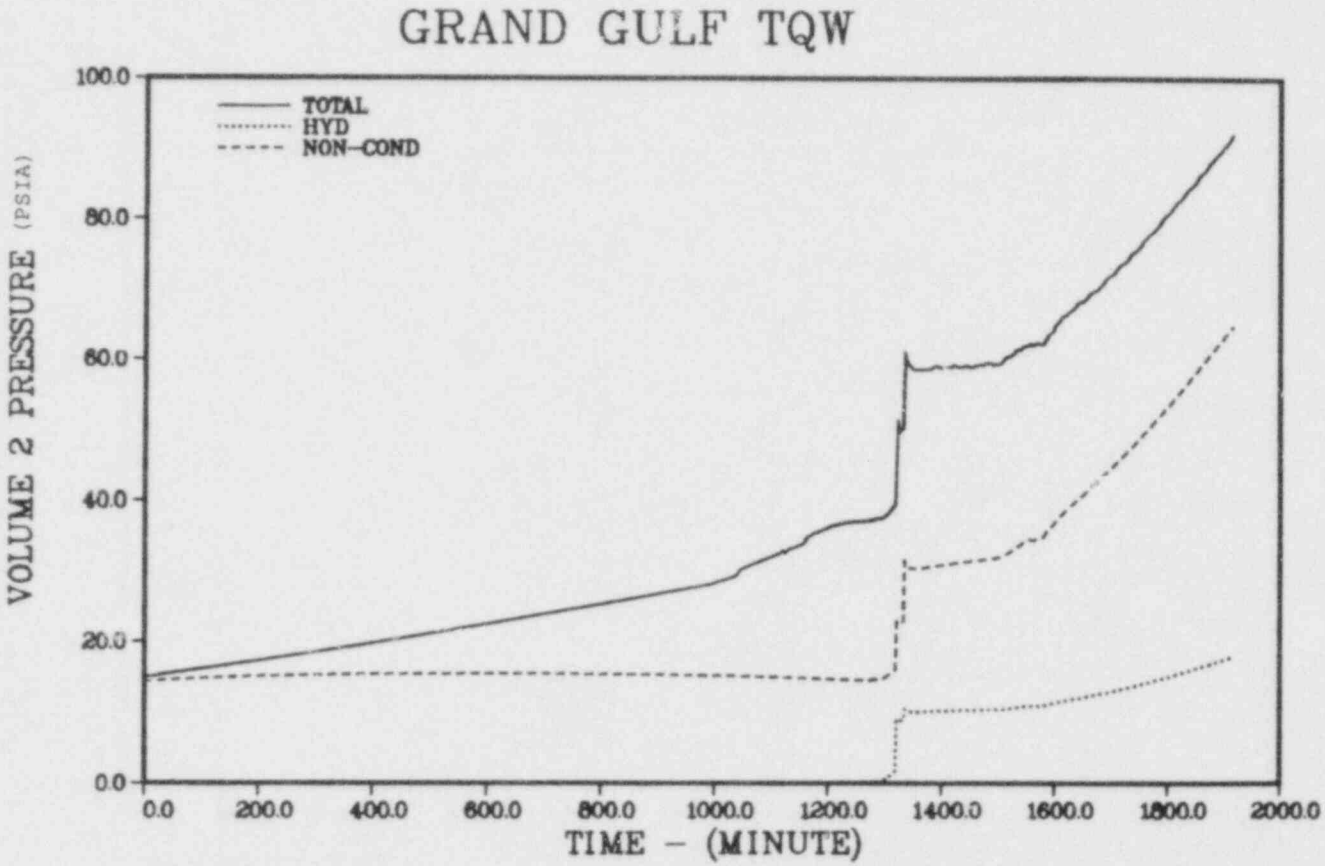

Figure C-2. Volume 2 Pressure Versus Time - TQW Sequence

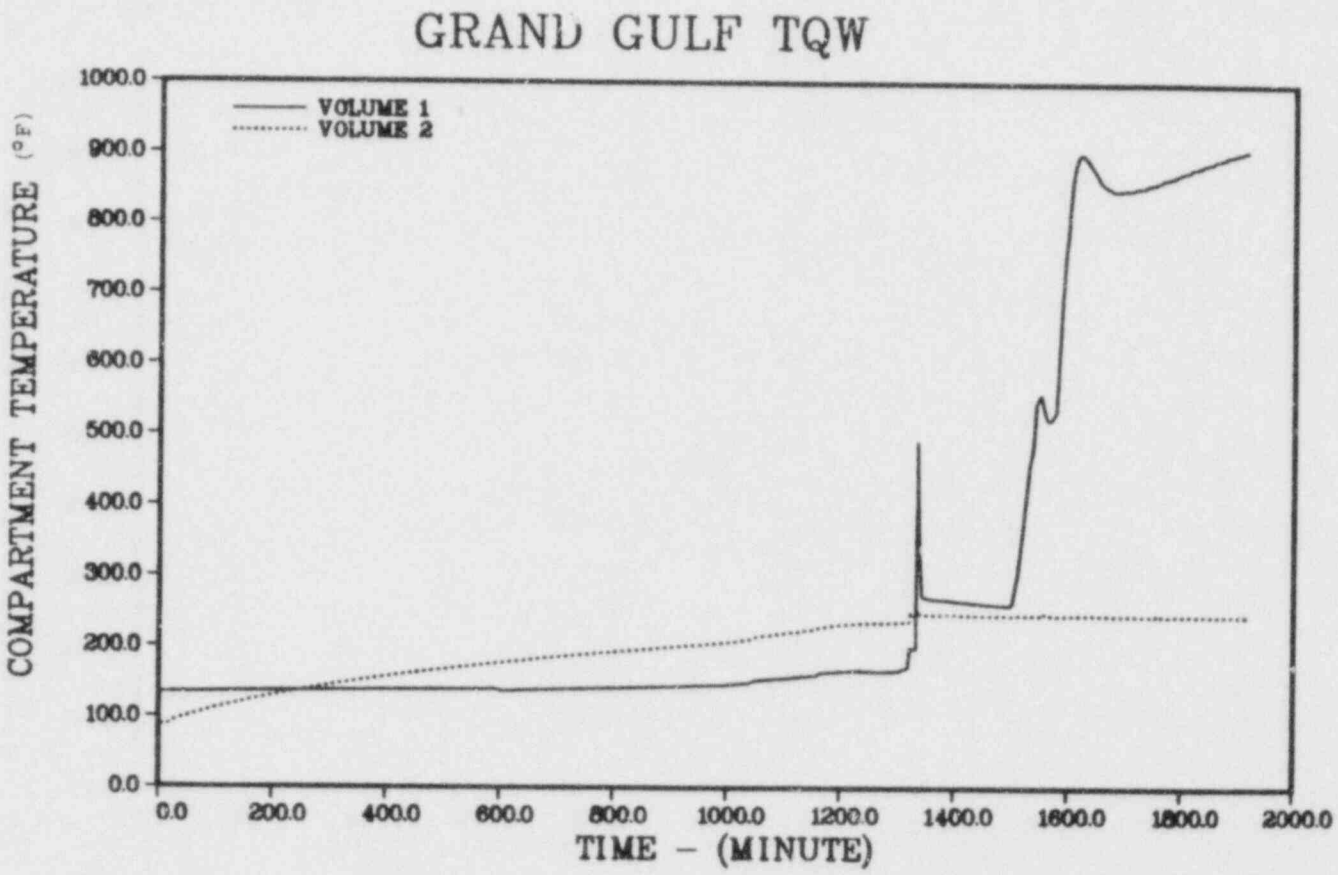

Figure C-3. Compartment Temperature Versus Time - TQW Sequence

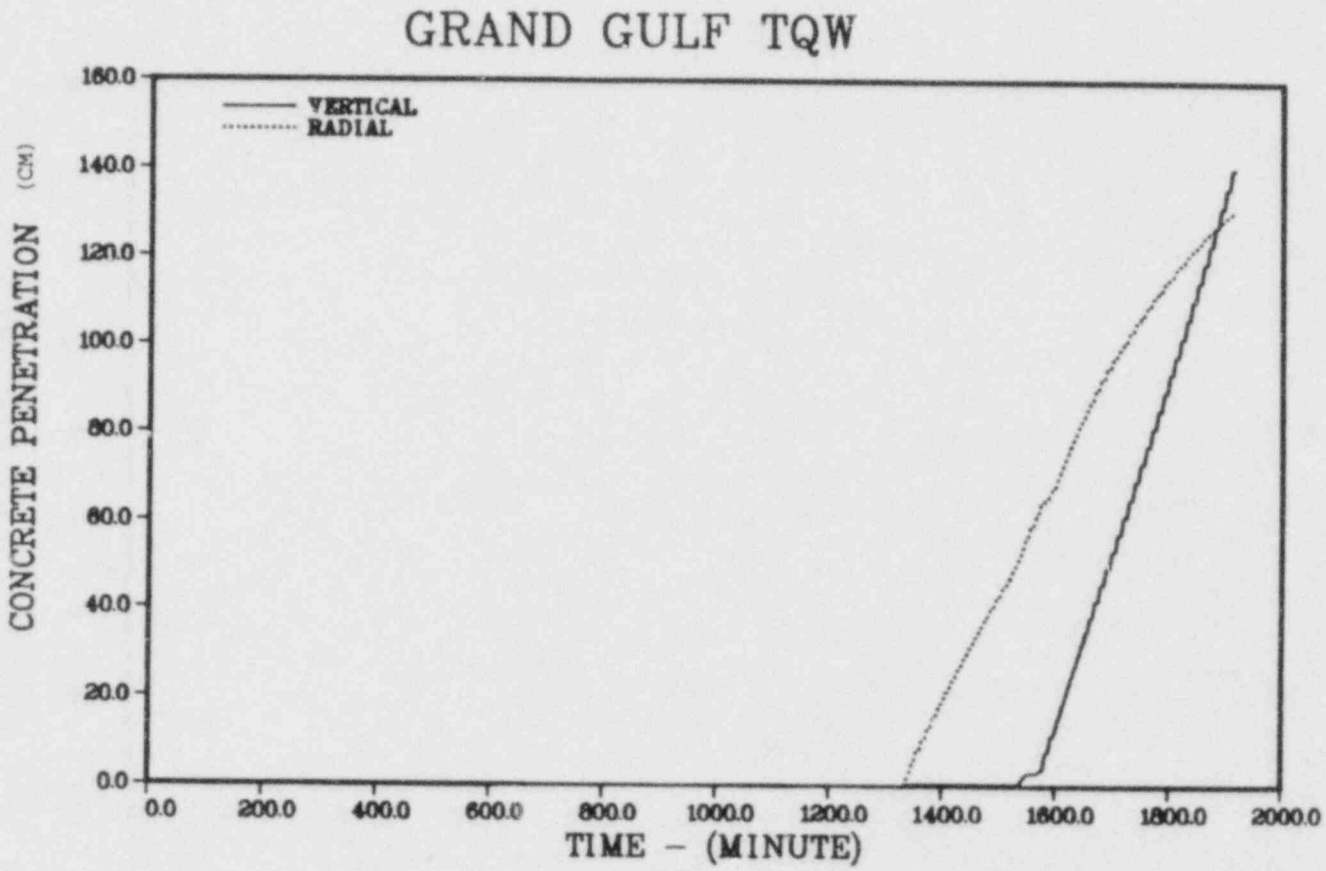

Figure C-4. Concrete Penetration Versus Time - TQW Sequence

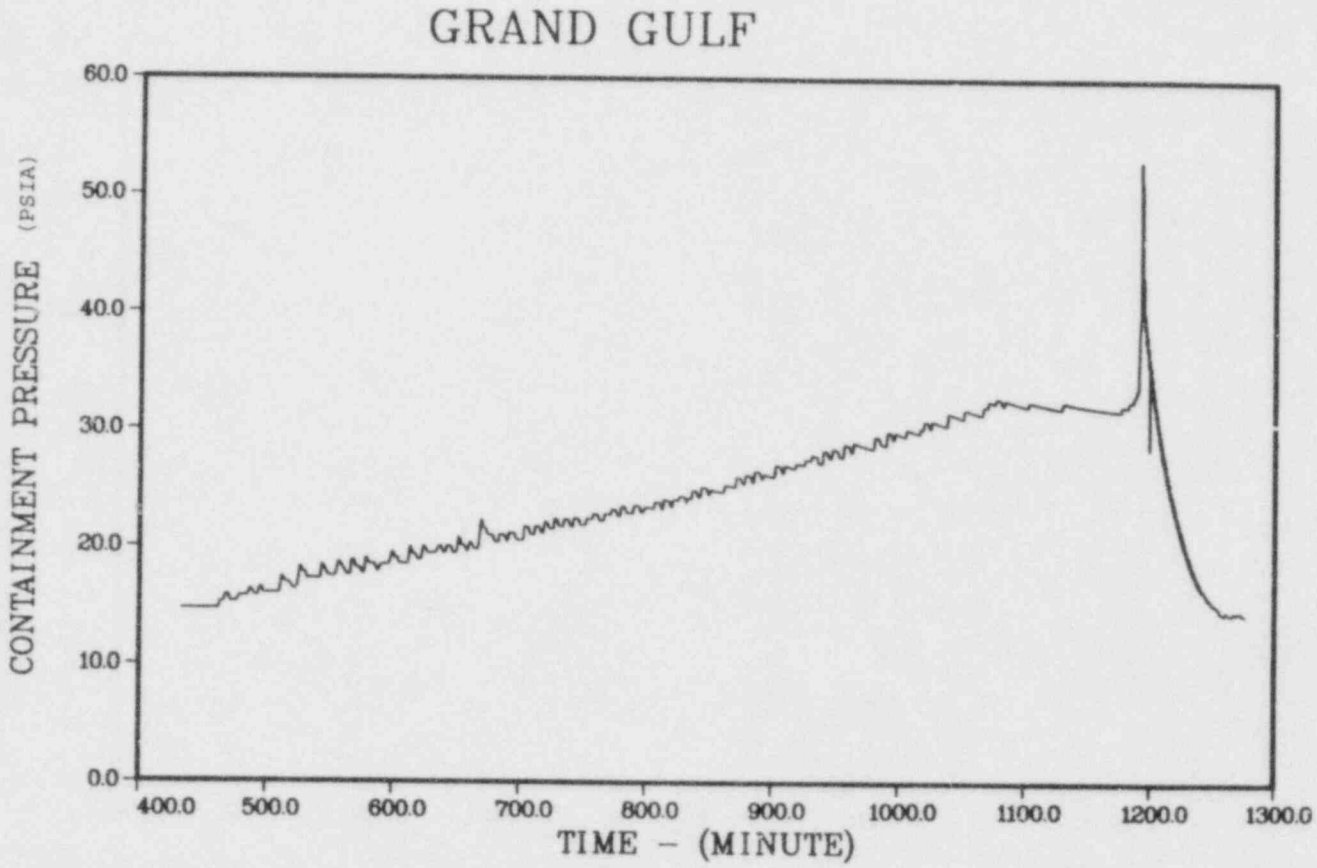

Figure C-5. Containment Pressure Versus Time - TPQI Sequence

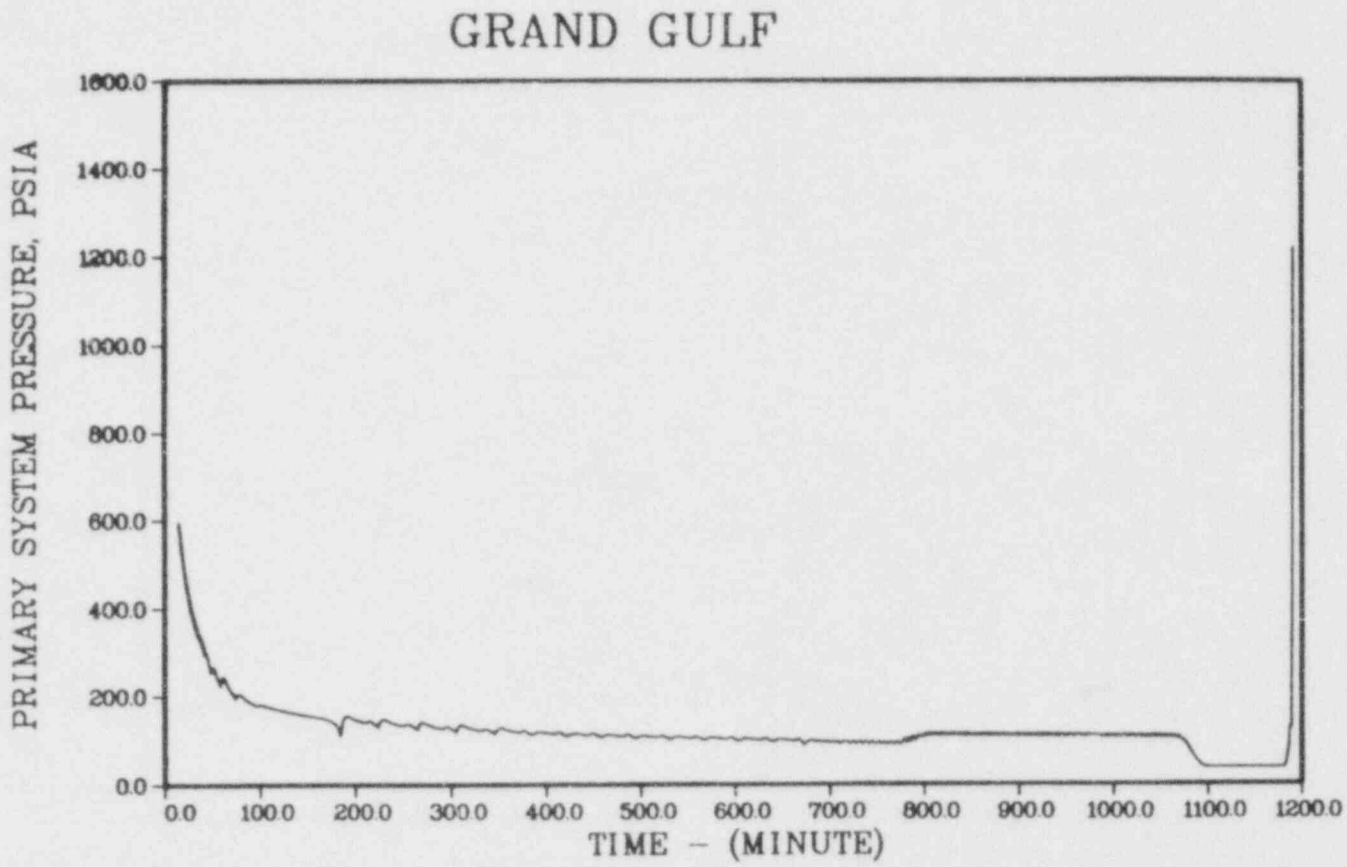

Figure C-6. Primary System Pressure Versus Time - TPQI Sequence

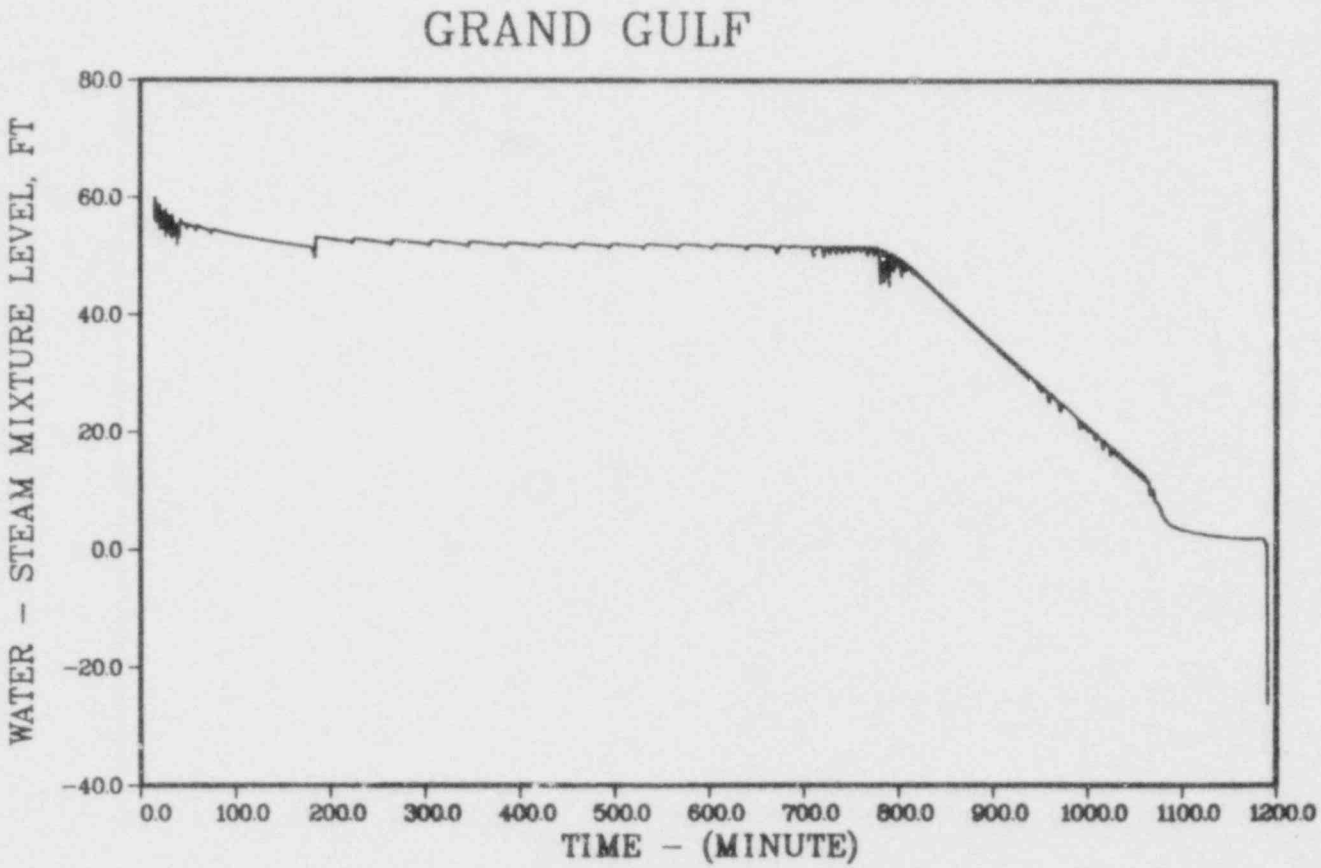

Figure C-7. Water/Steam Mixture Level Versus Time - TPQI Sequence

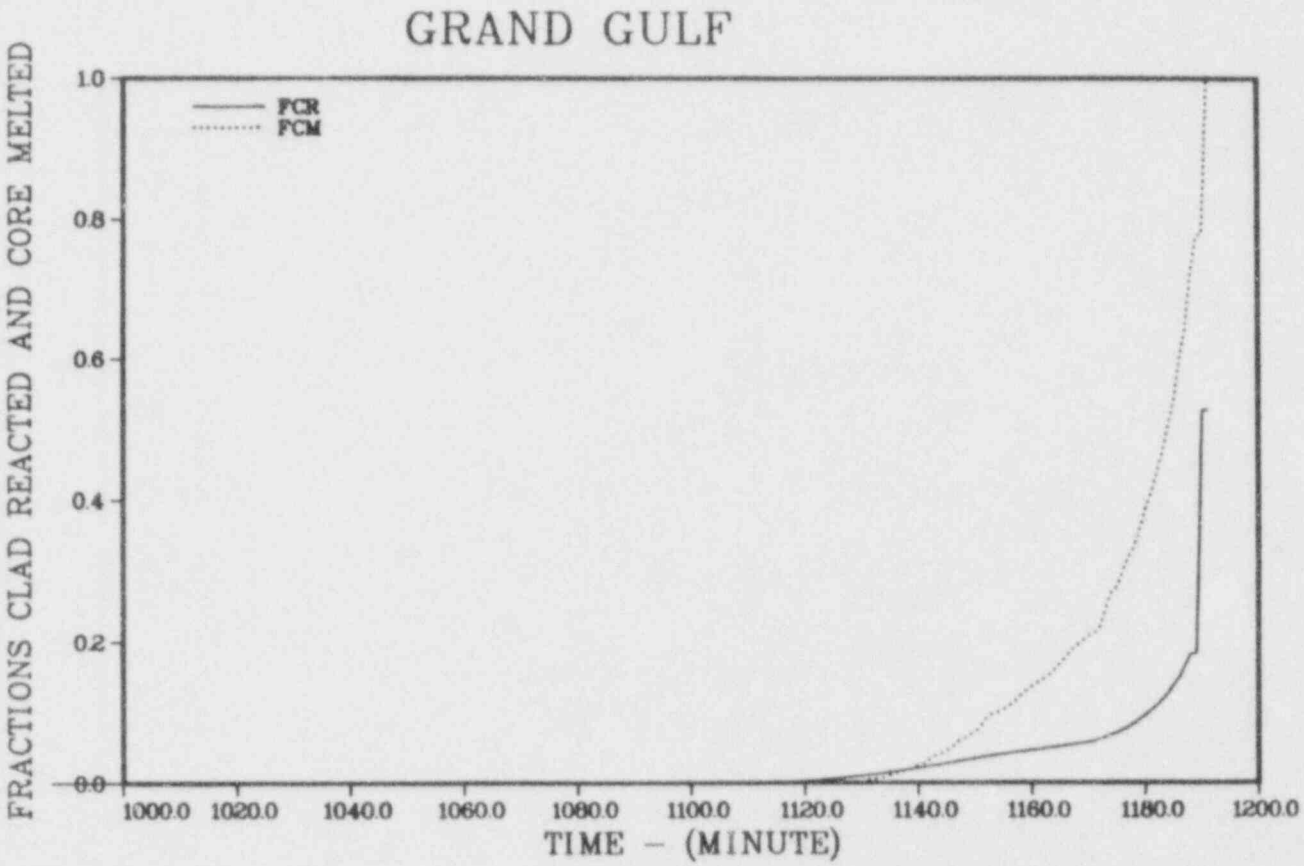

Figure C-8. Fraction of Clad Reacted and Core Melted Versus Time - TPQI Sequence

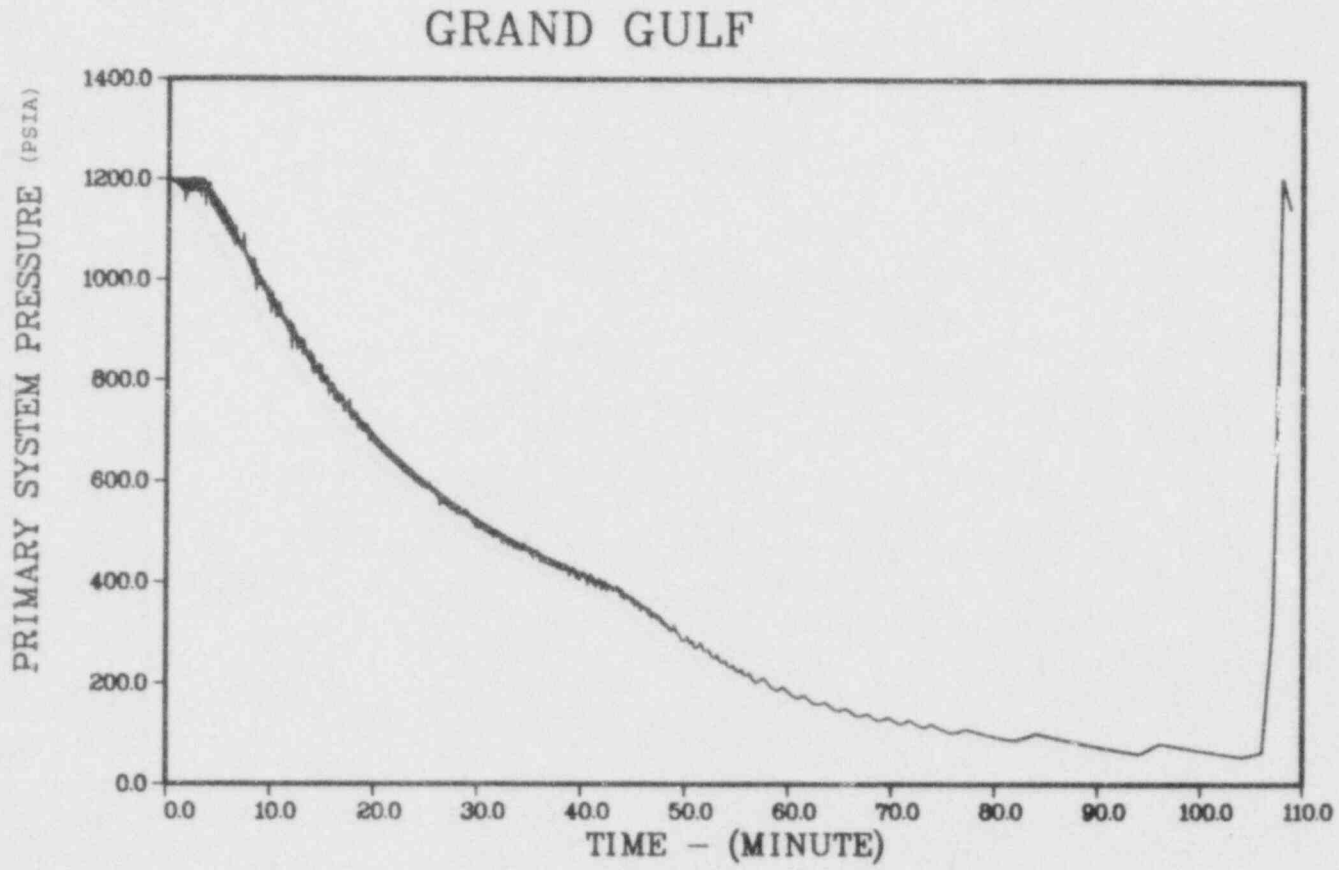

Figure C-9. Primary System Pressure Versus Time - TPQE Sequence

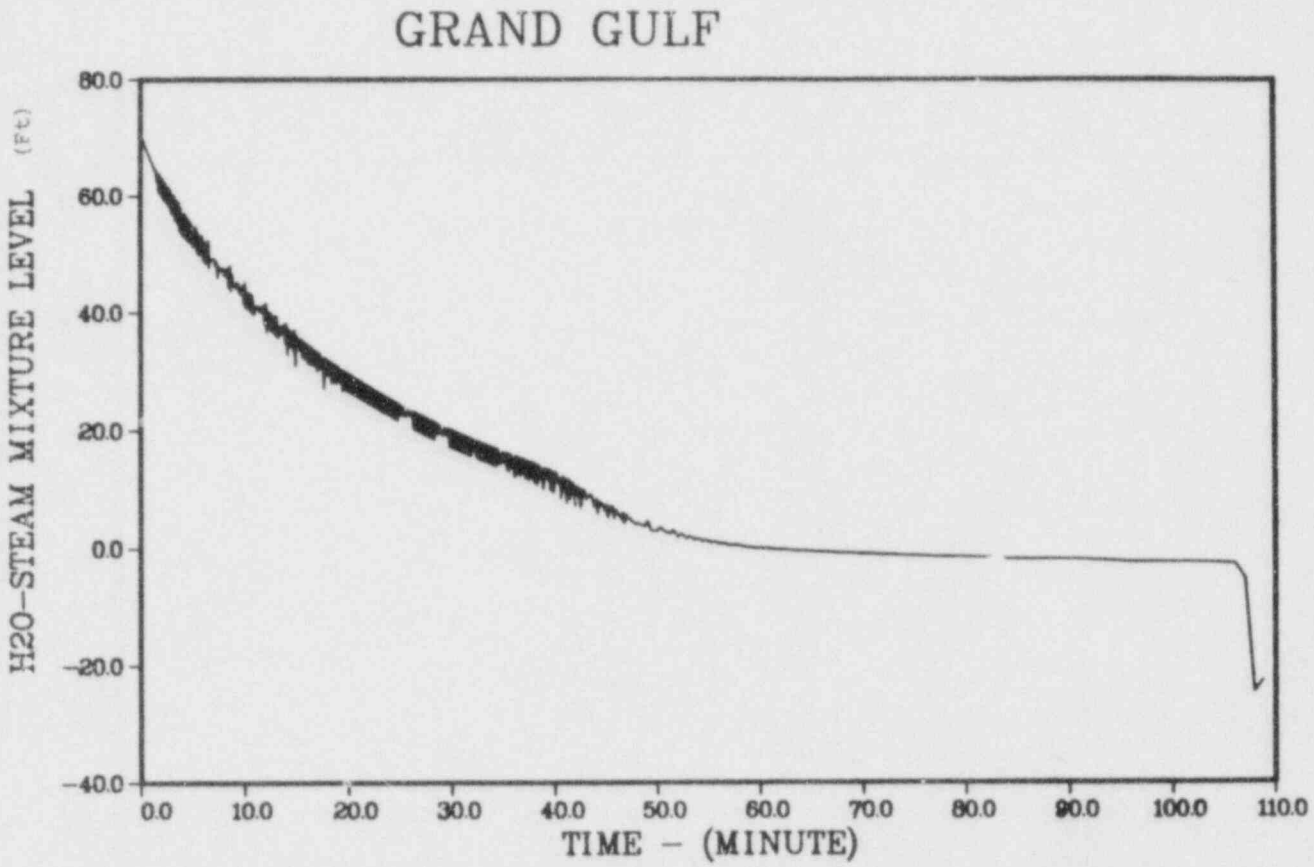

Figure C-10. H_2O/Steam Mixture Level Versus Time - TPQE Sequence

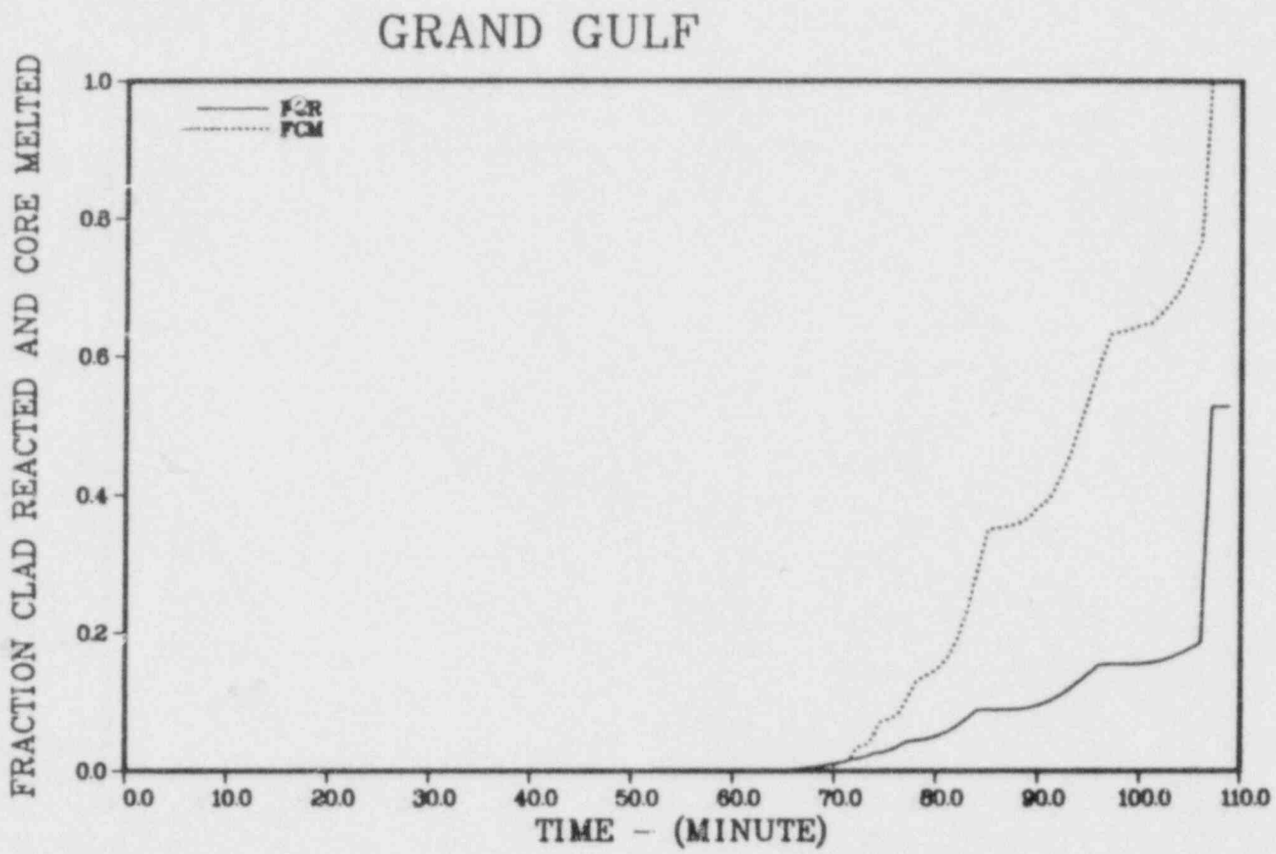

Figure C-11. Fraction of Clad Reacted and Core Melted Versus Time - TPQE Sequence

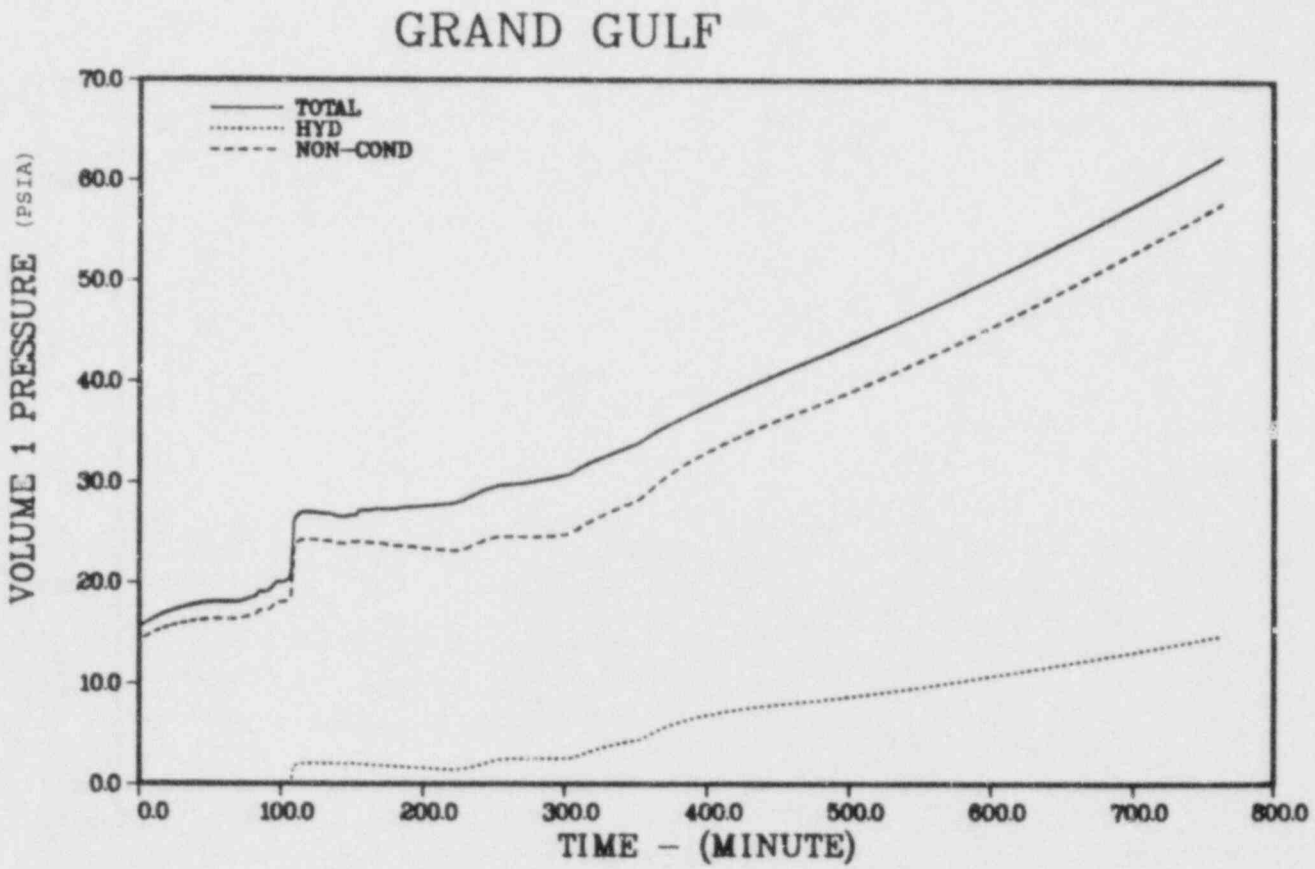

Figure C-12. Volume 1 Pressure Versus Time - TPQE Sequence

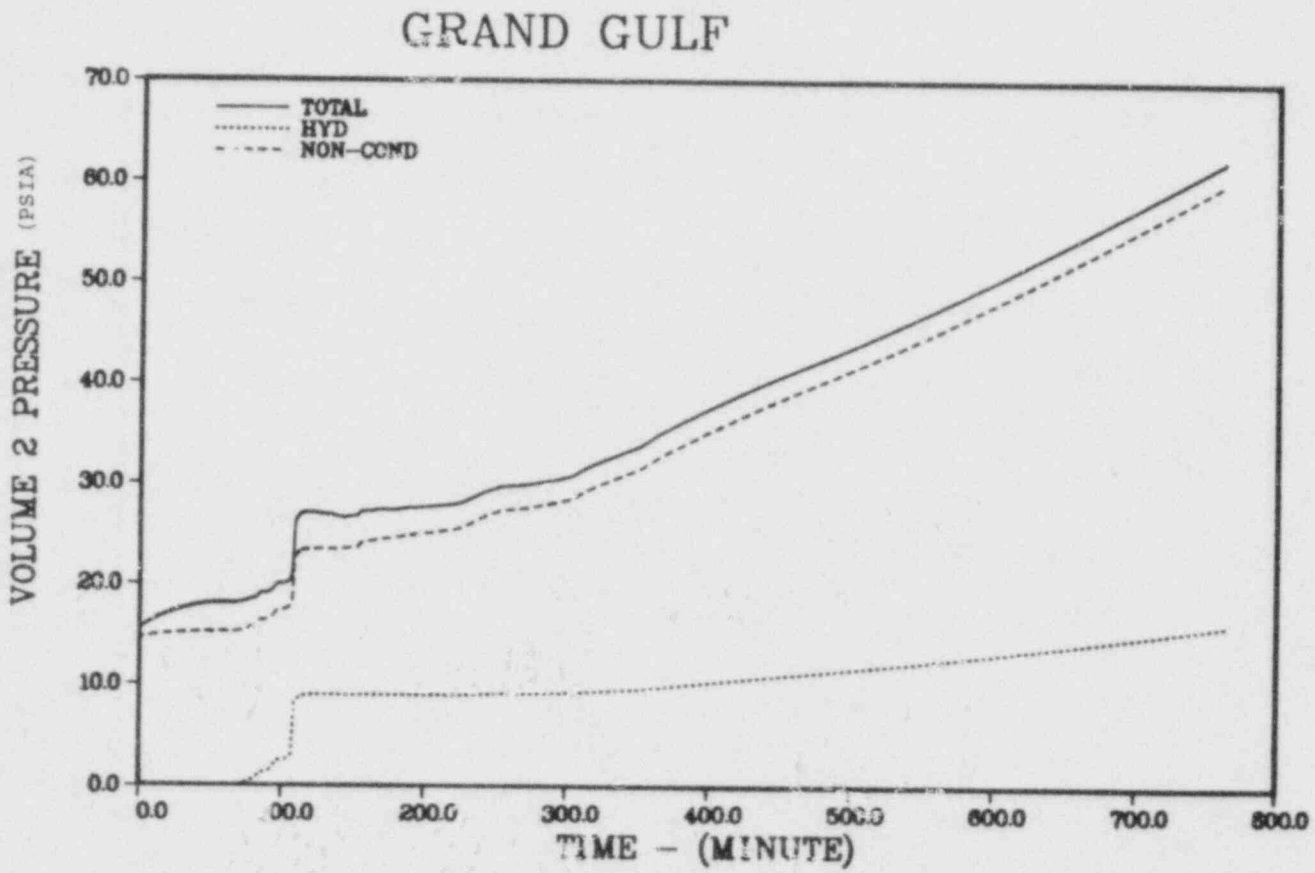

Figure C-13. Volume 2 Pressure Versus Time - TPQE Sequence

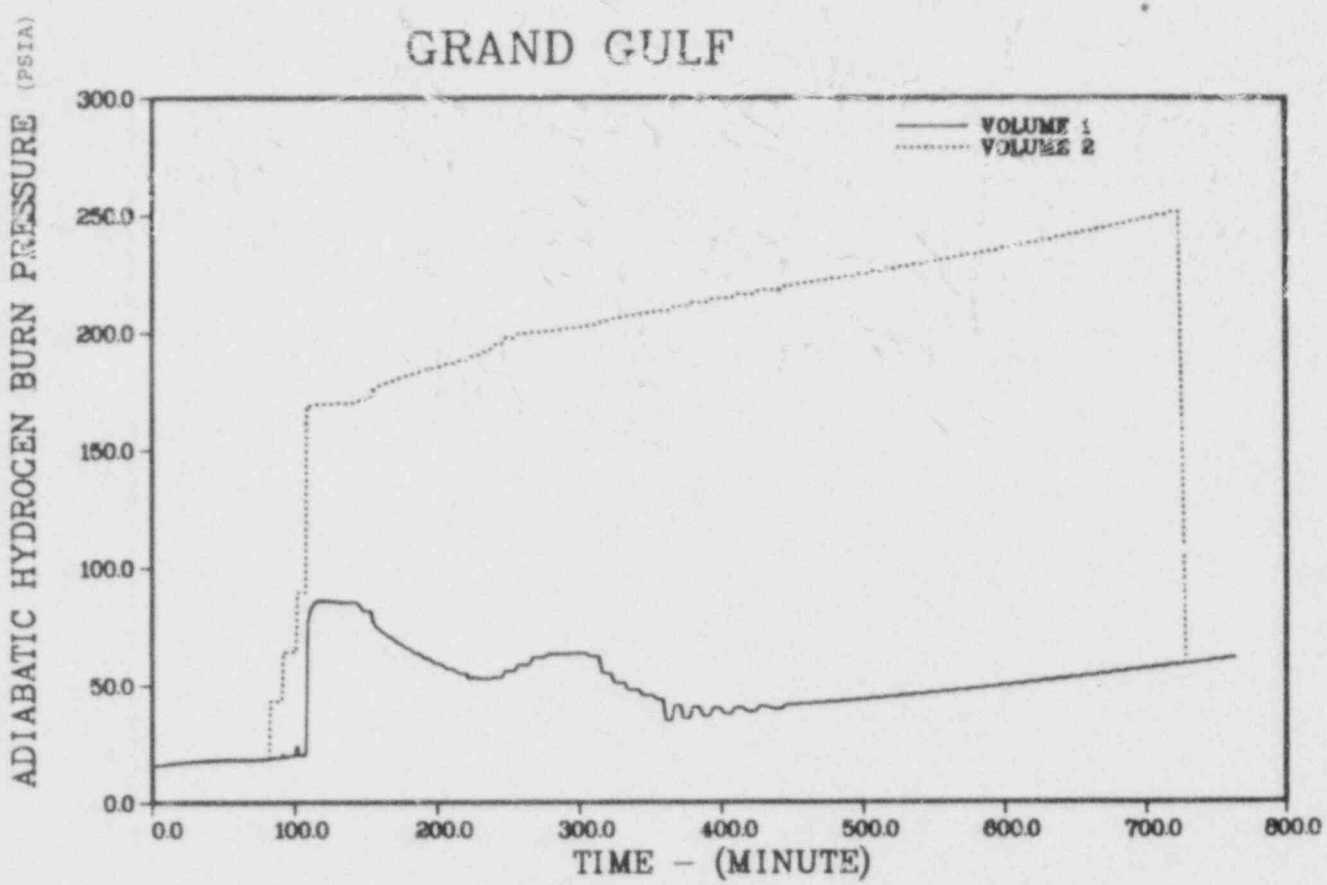

Figure C-14. Adiabatic Hydrogen Burn Pressure Versus Time - TPQE Sequence

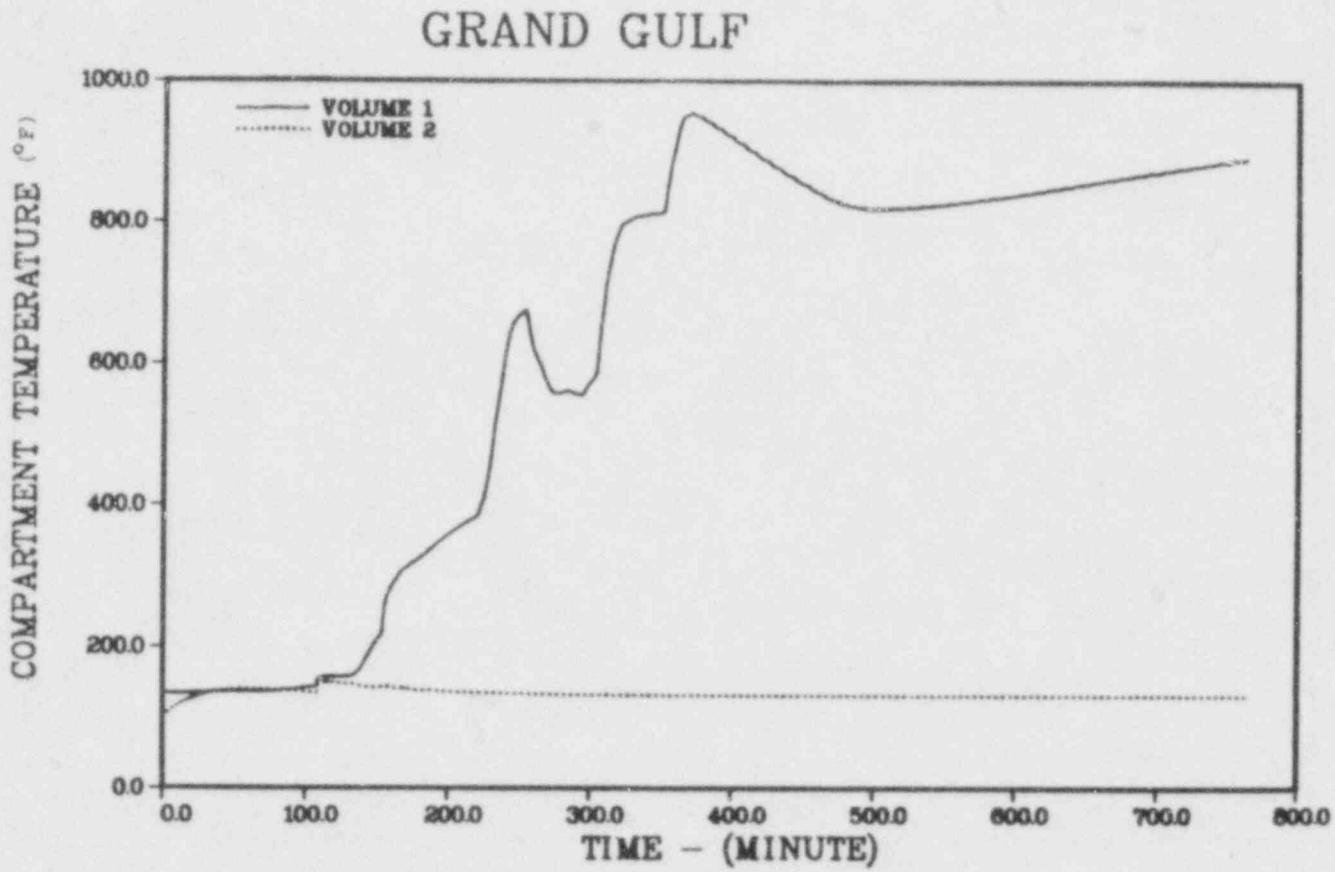

Figure C-15. Compartment Temperature Versus Time - TPQE Sequence

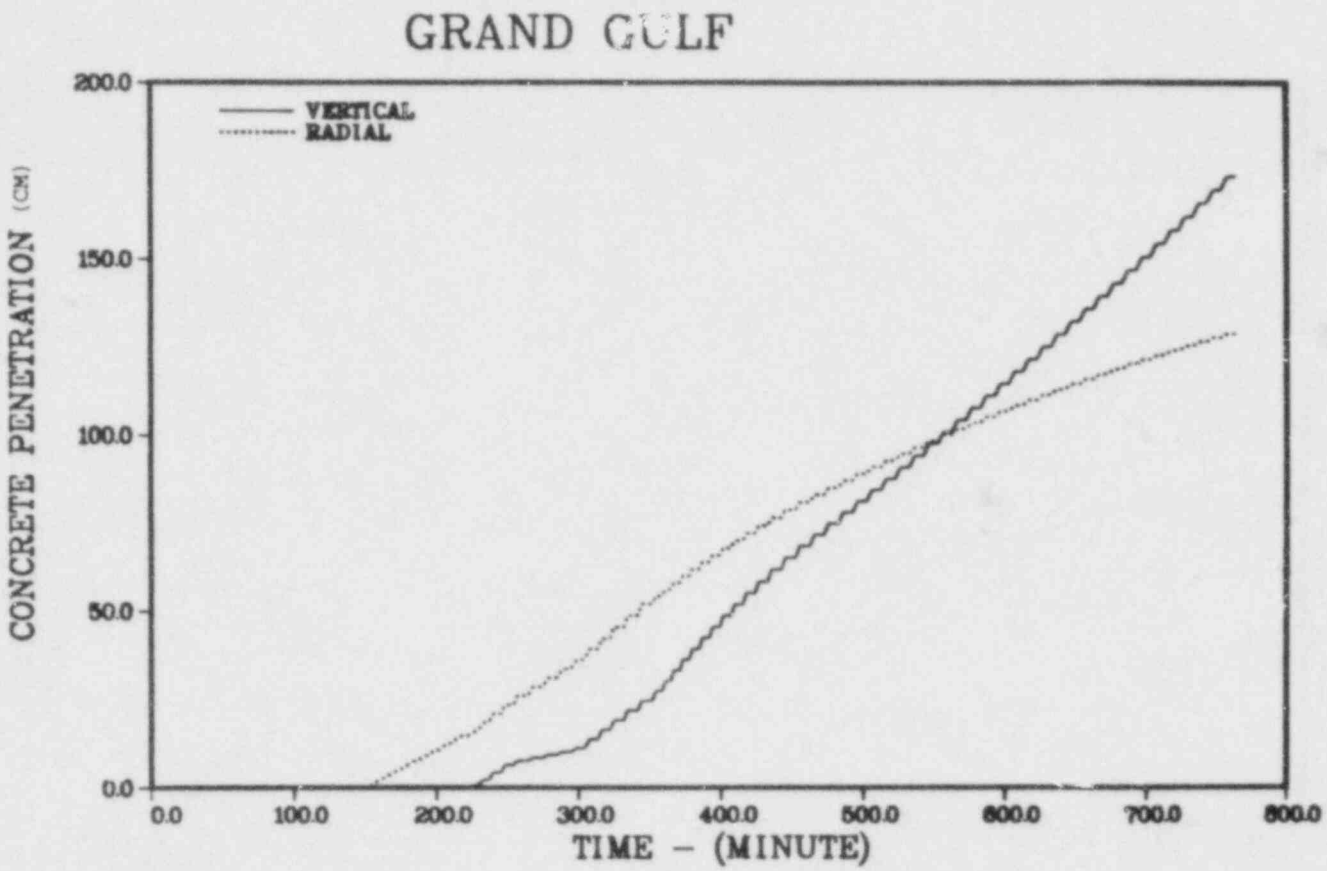

Figure C-16. Concrete Penetration Versus Time - TPQE Sequence

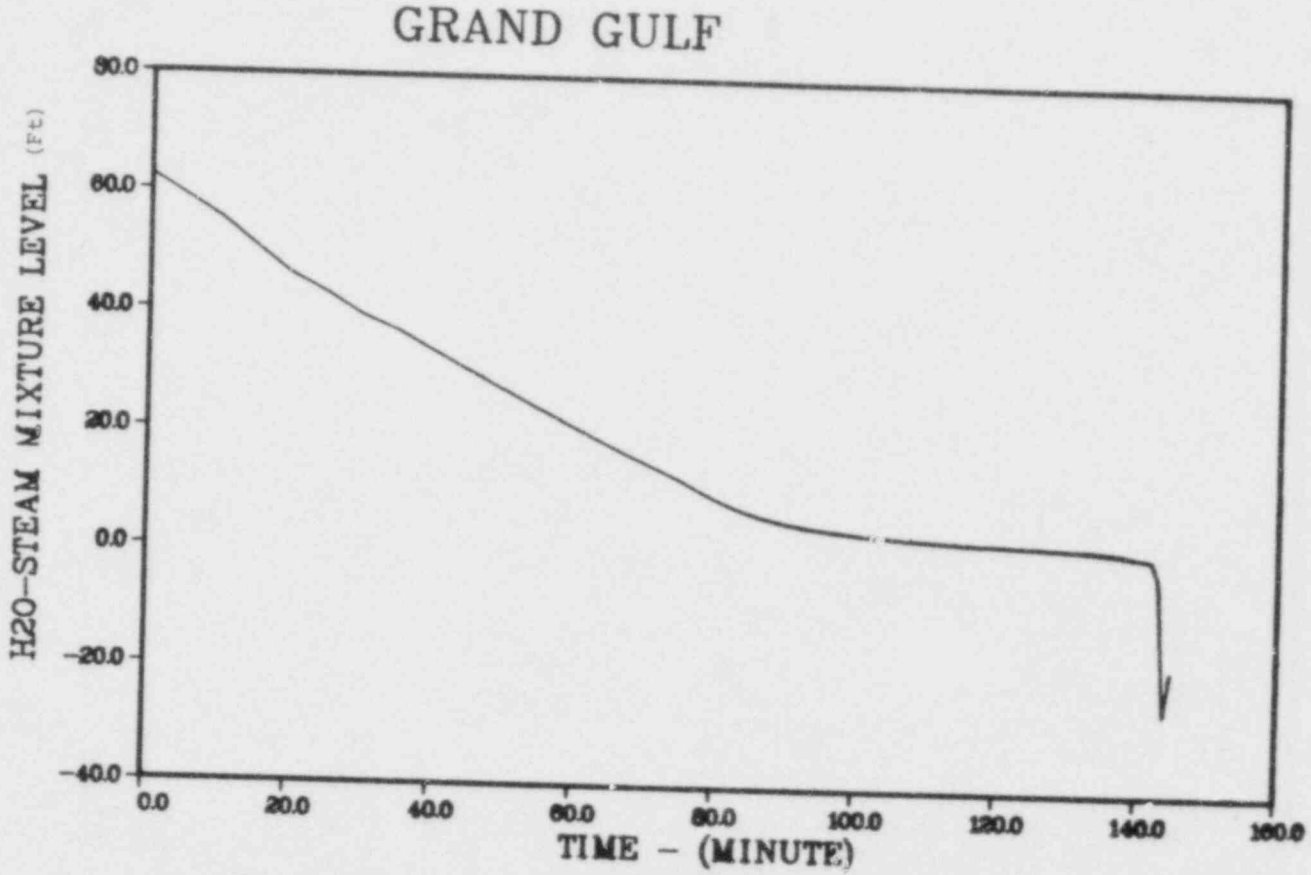

Figure C-17. H_2O/Steam Mixture Level Versus Time - TQUV Sequence

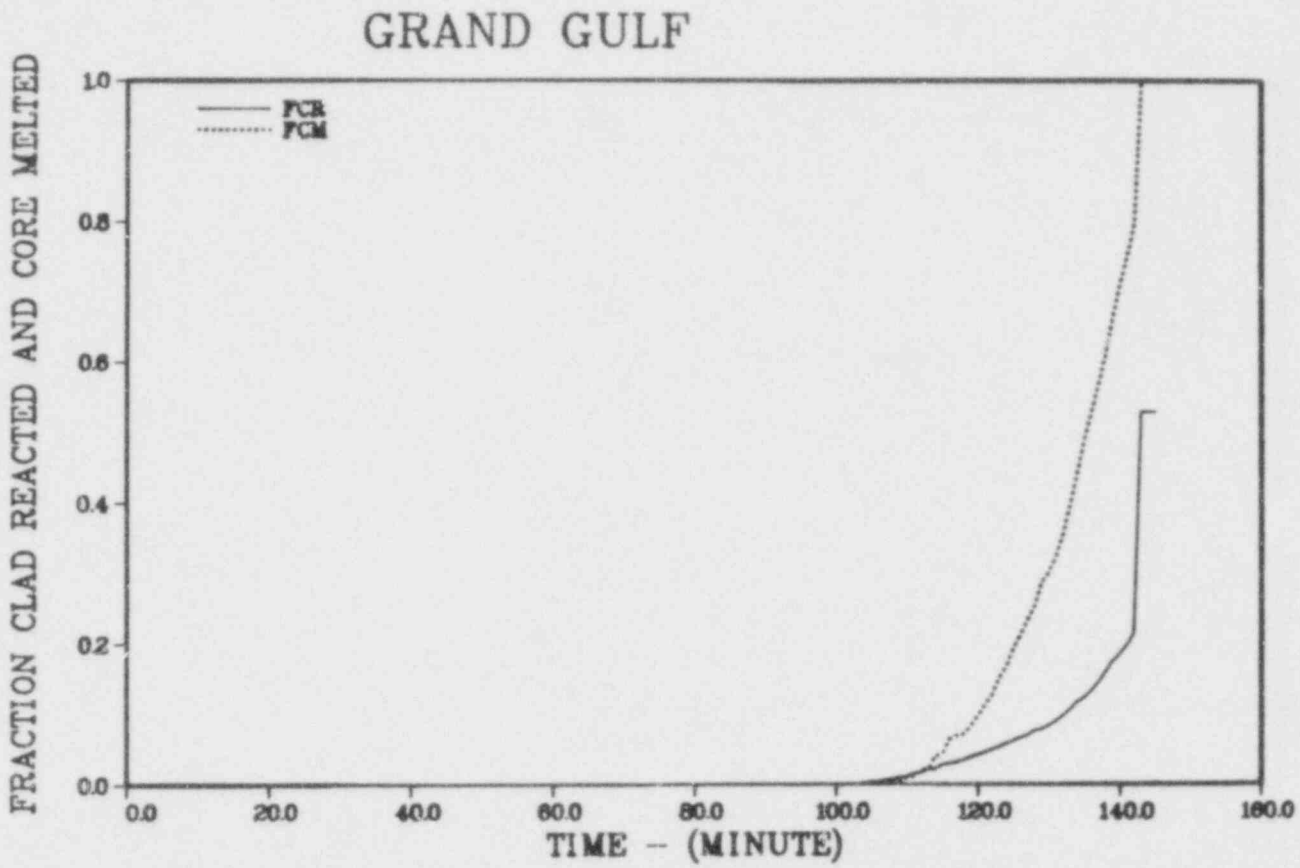

Figure C-18. Fraction of Clad Reacted and Core Melted Versus Time - TQUV Sequence

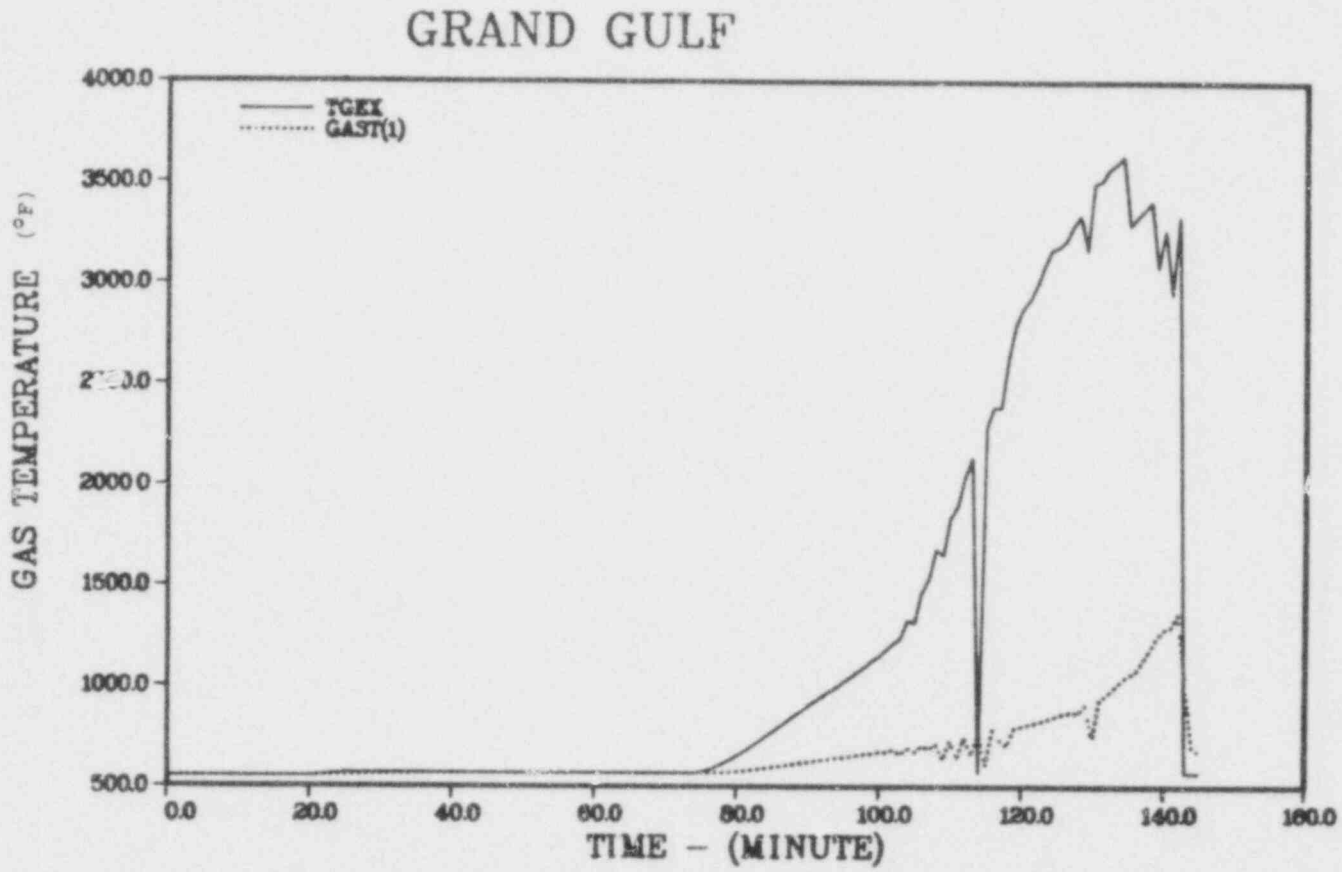

Figure C-19. Gas Temperature Versus Time - TQUV Sequence

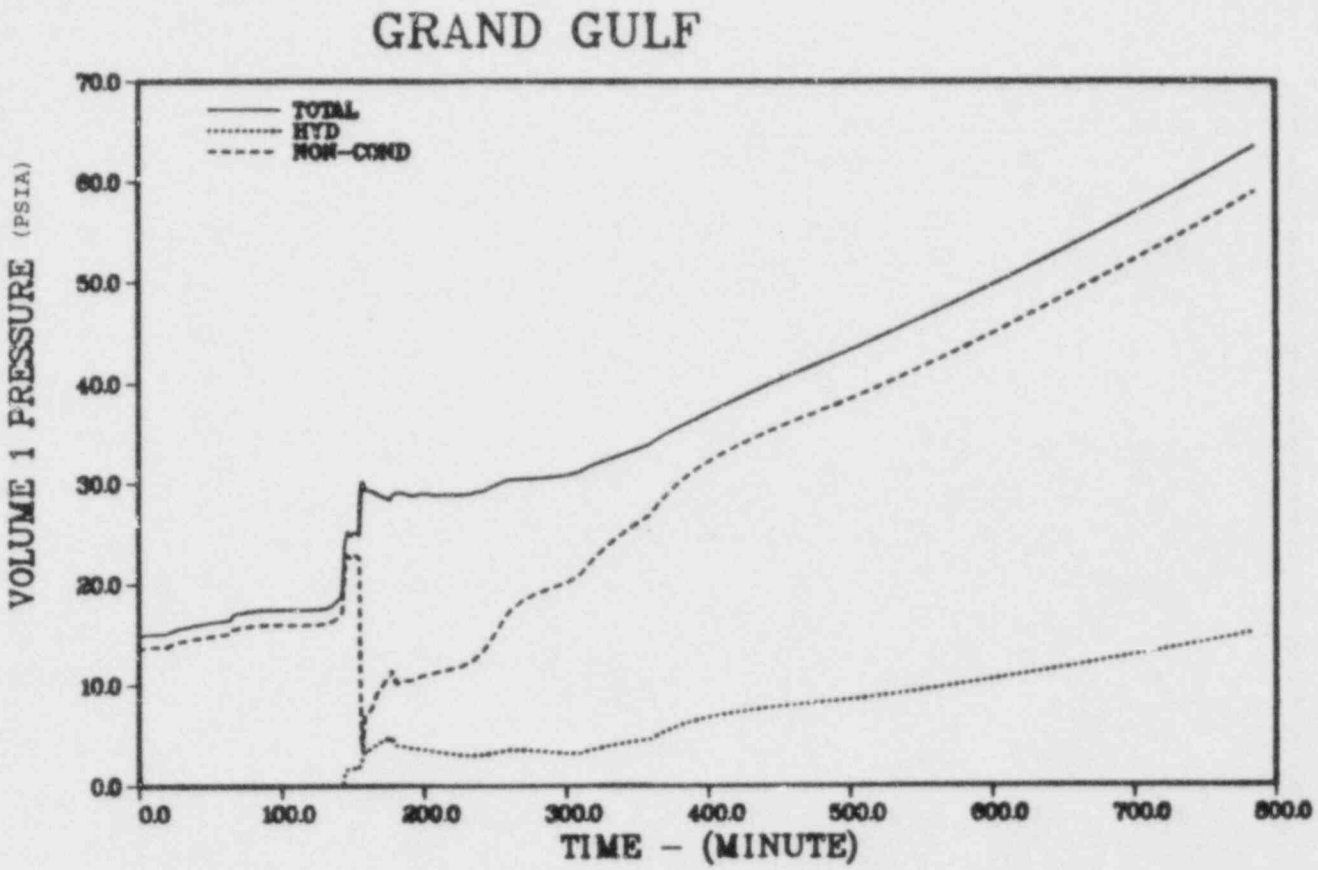

Figure C-20. Volume 1 Pressure Versus Time - TQUV Sequence

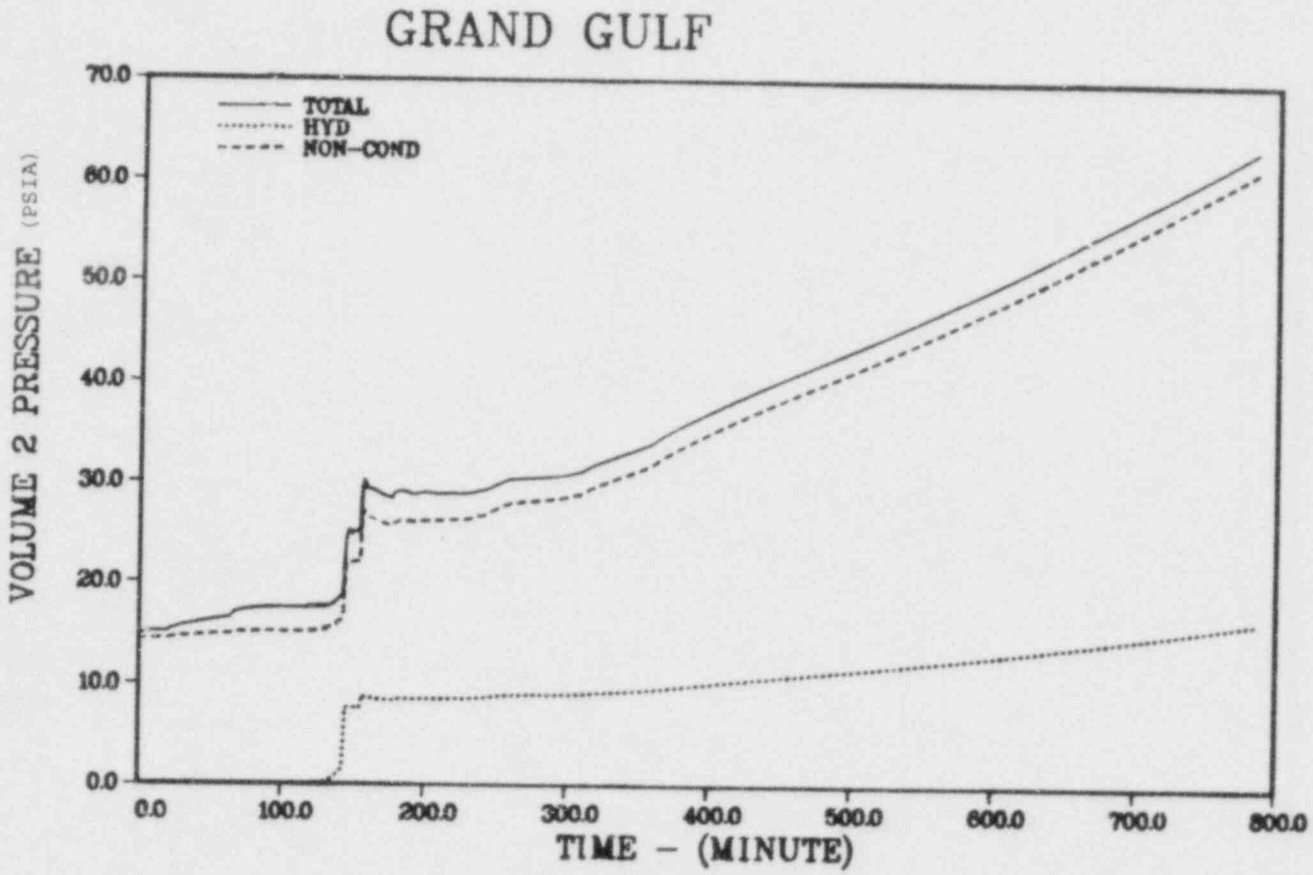

Figure C-21. Volume 2 Pressure Versus Time - TQUV Sequence

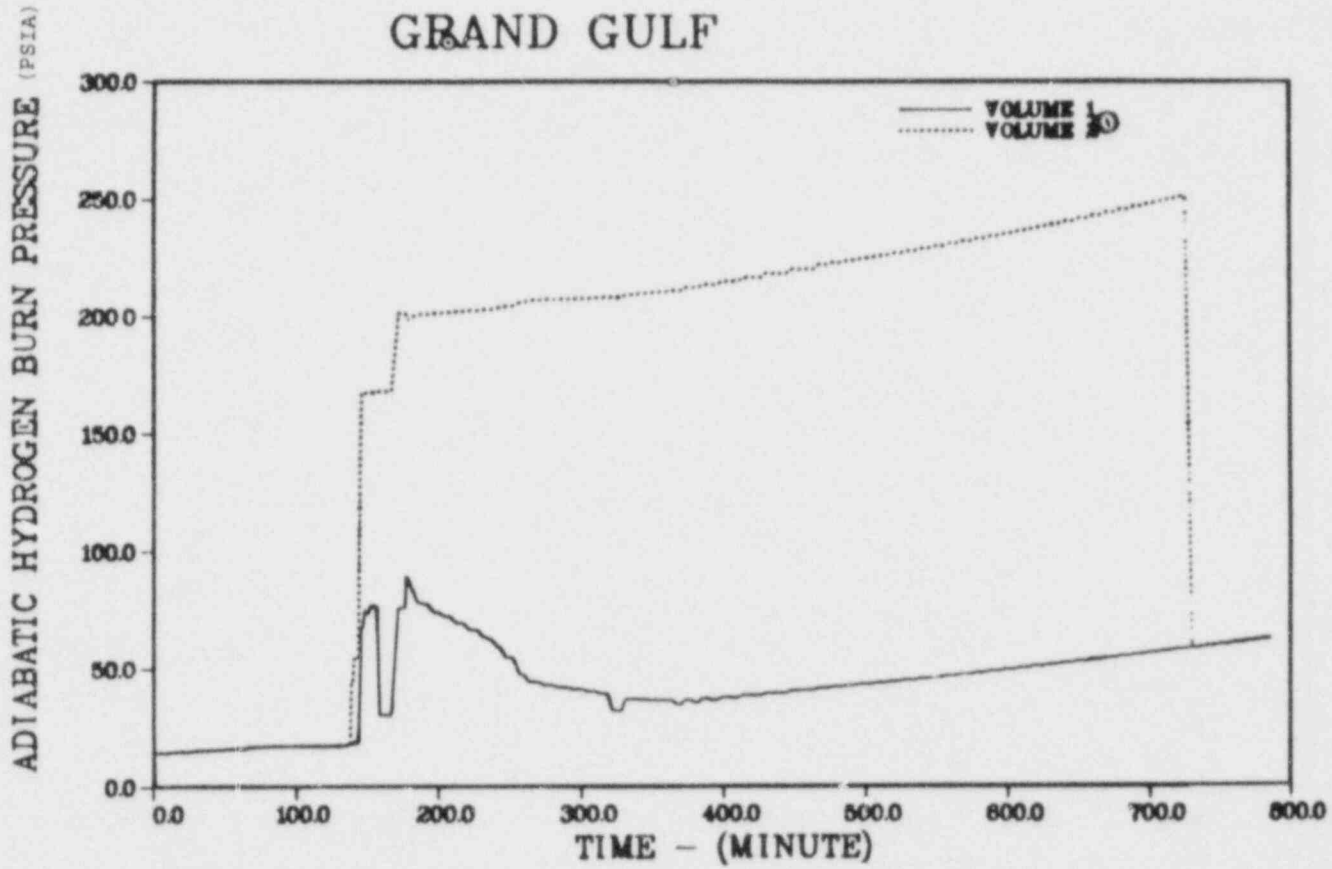

Figure C-22. Adiabatic Hydrogen Burn Pressure Versus Time - TQUV Sequence

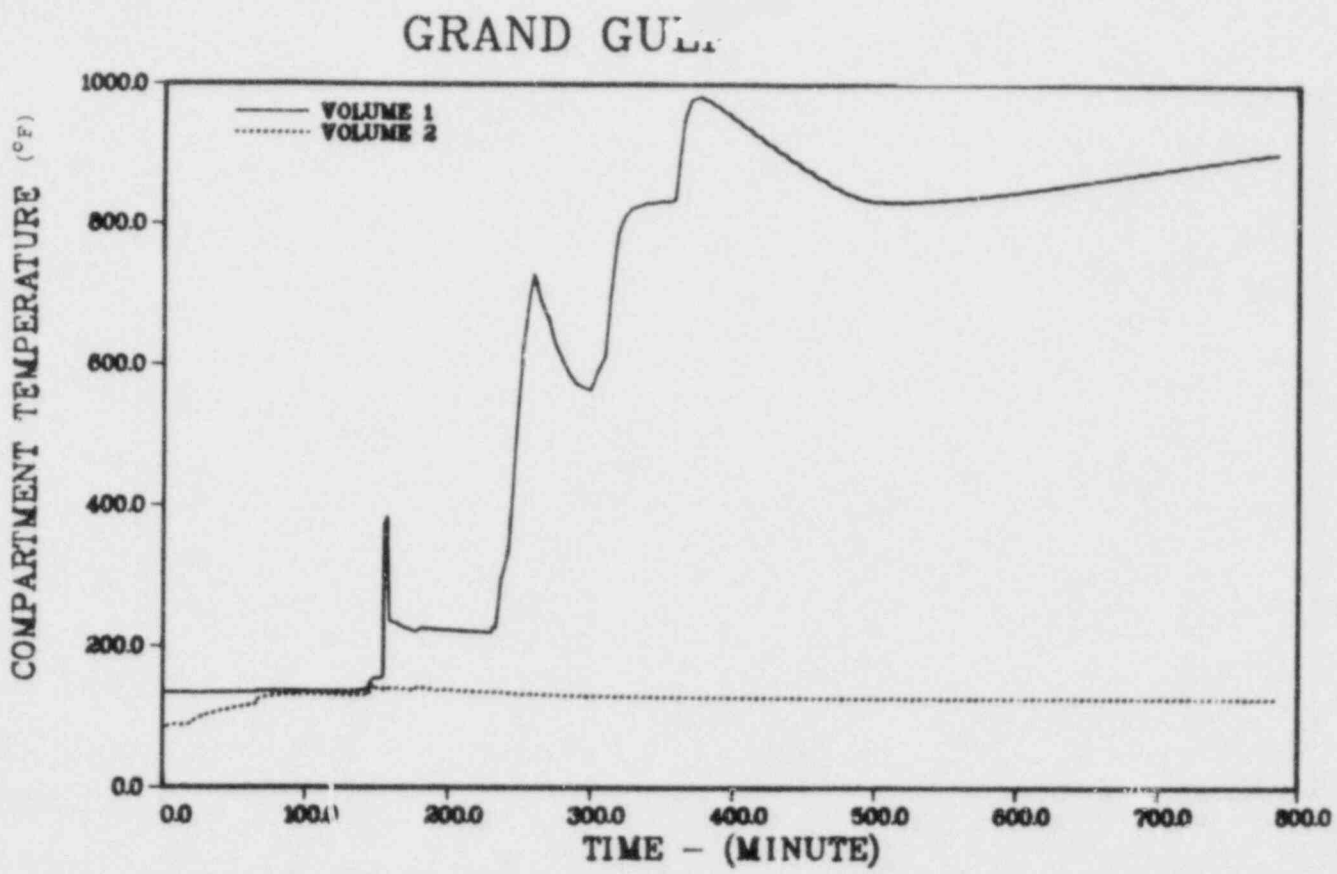

Figure C-23. Compartment Temperature Versus Time - TQUV Sequence

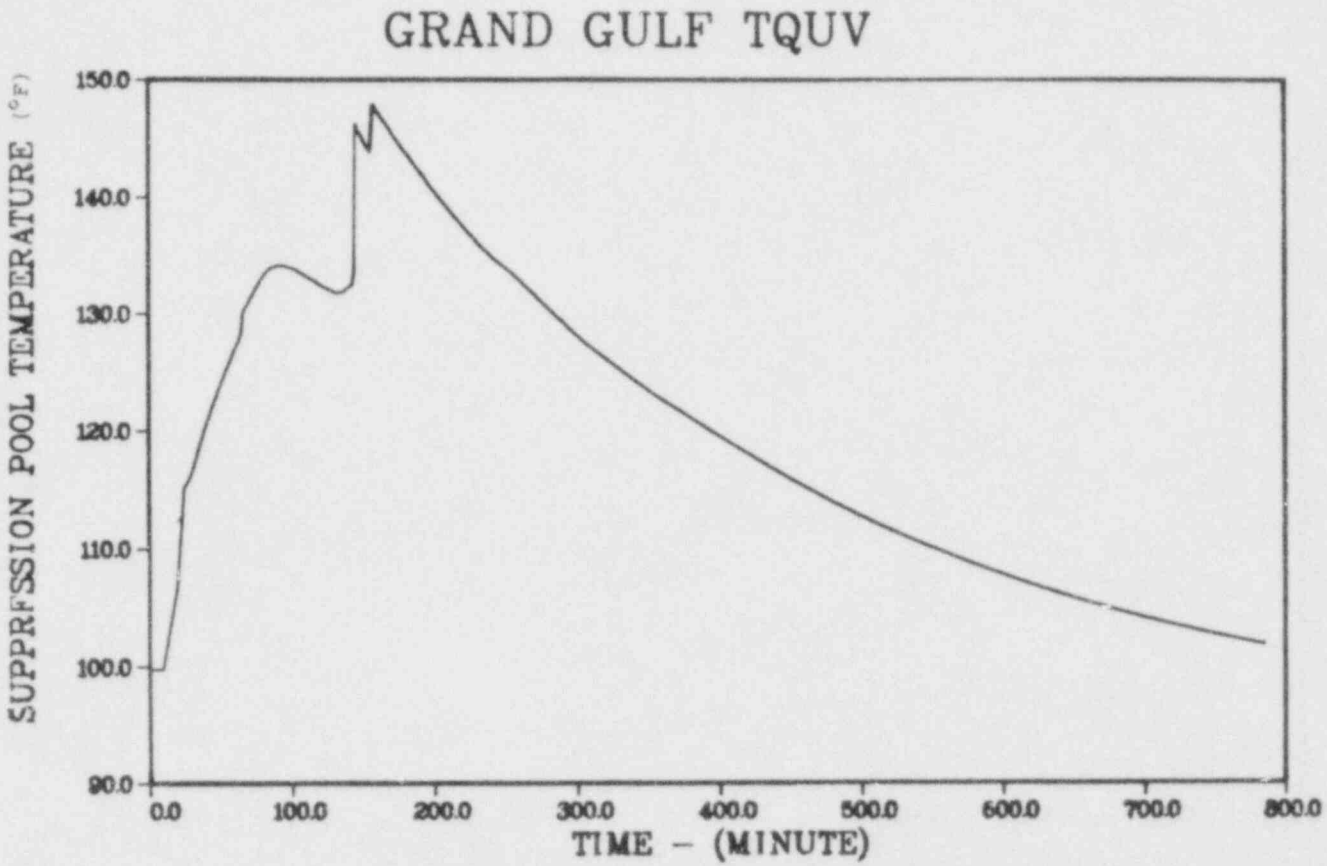

Figure C-24. Suppression Pool Temperature Versus Time - TQUV Sequence

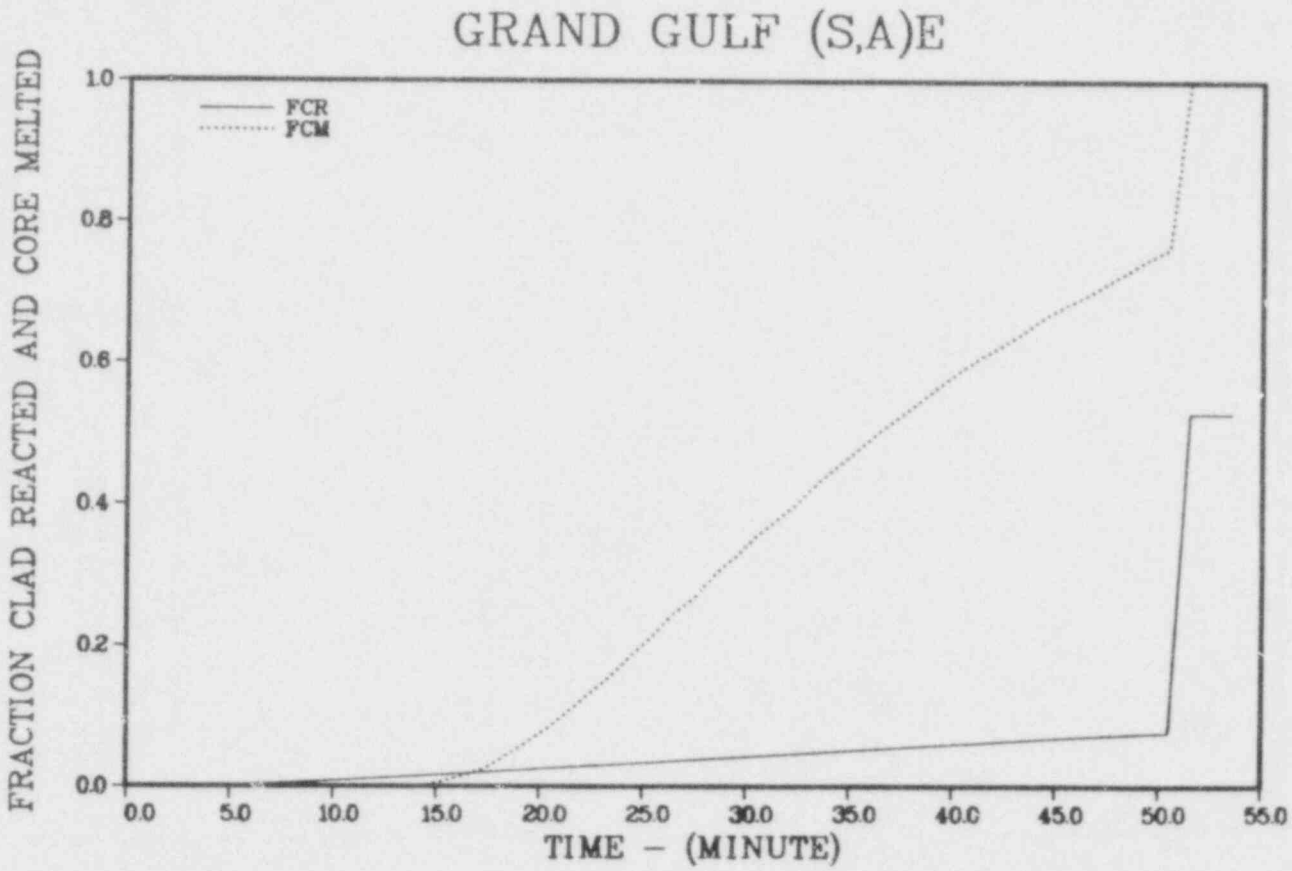

Figure C-25. Fraction of Clad Reacted and Core Melted Versus Time - SE and AE Sequences

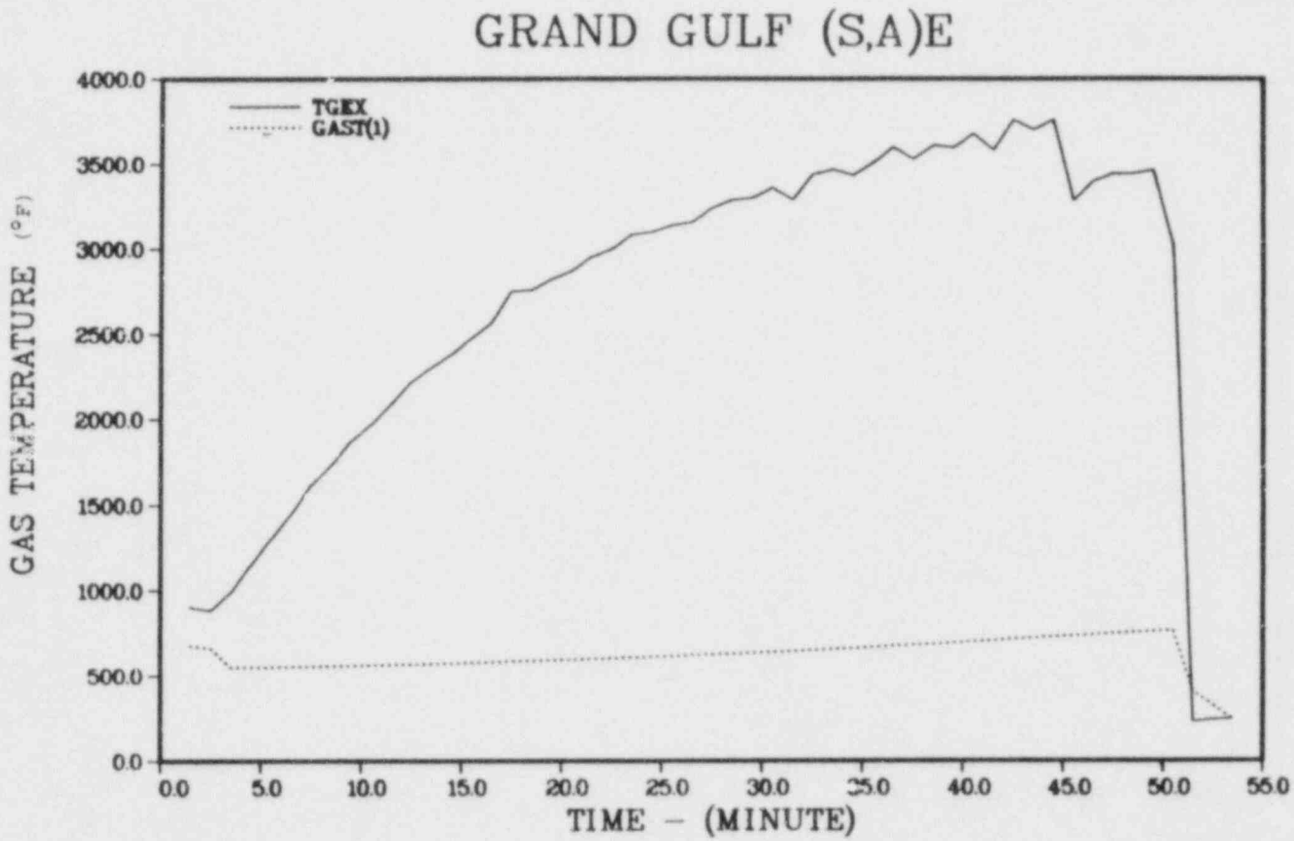

Figure C-26. Gas Temperature Versus Time - SE and AE Sequences

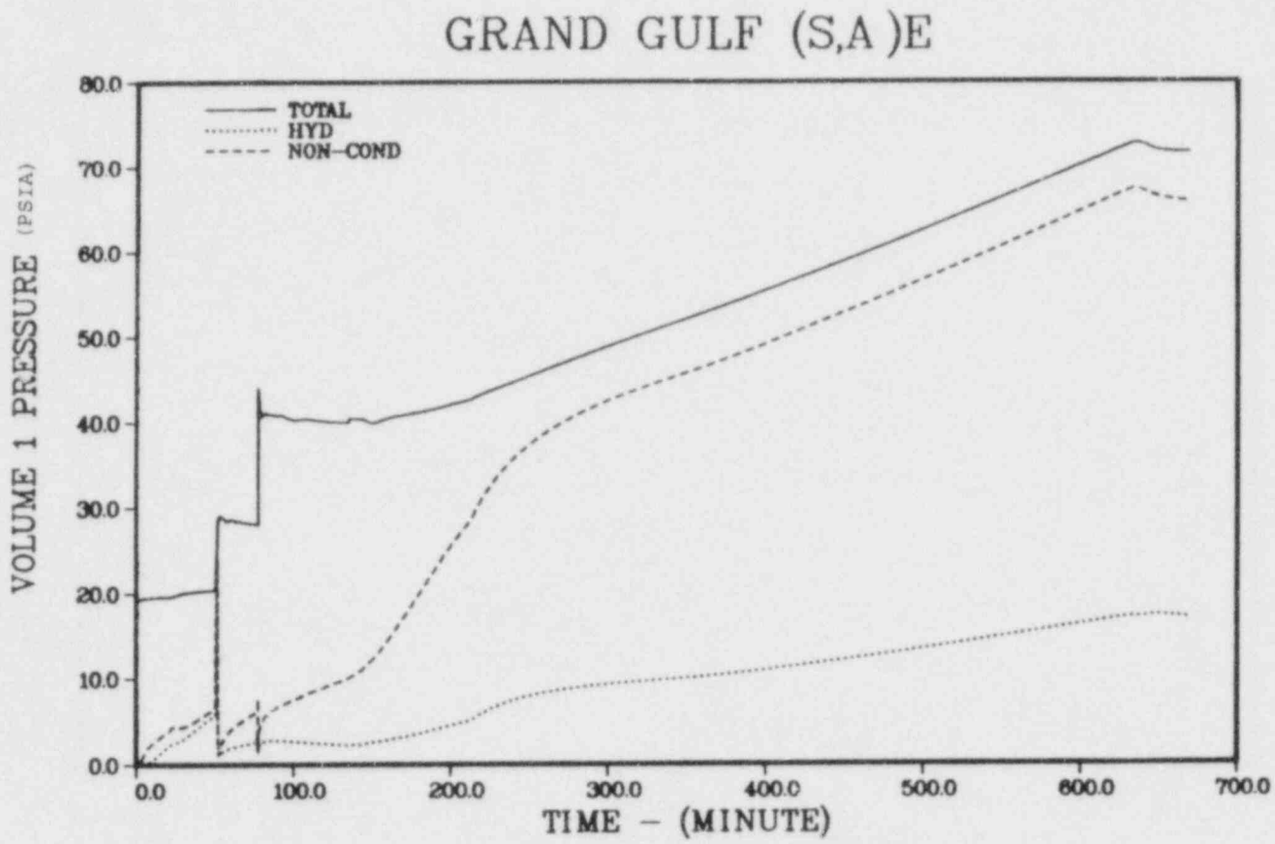

Figure C-27. Volume 1 Pressure Versus Time - SE and AE Swquences

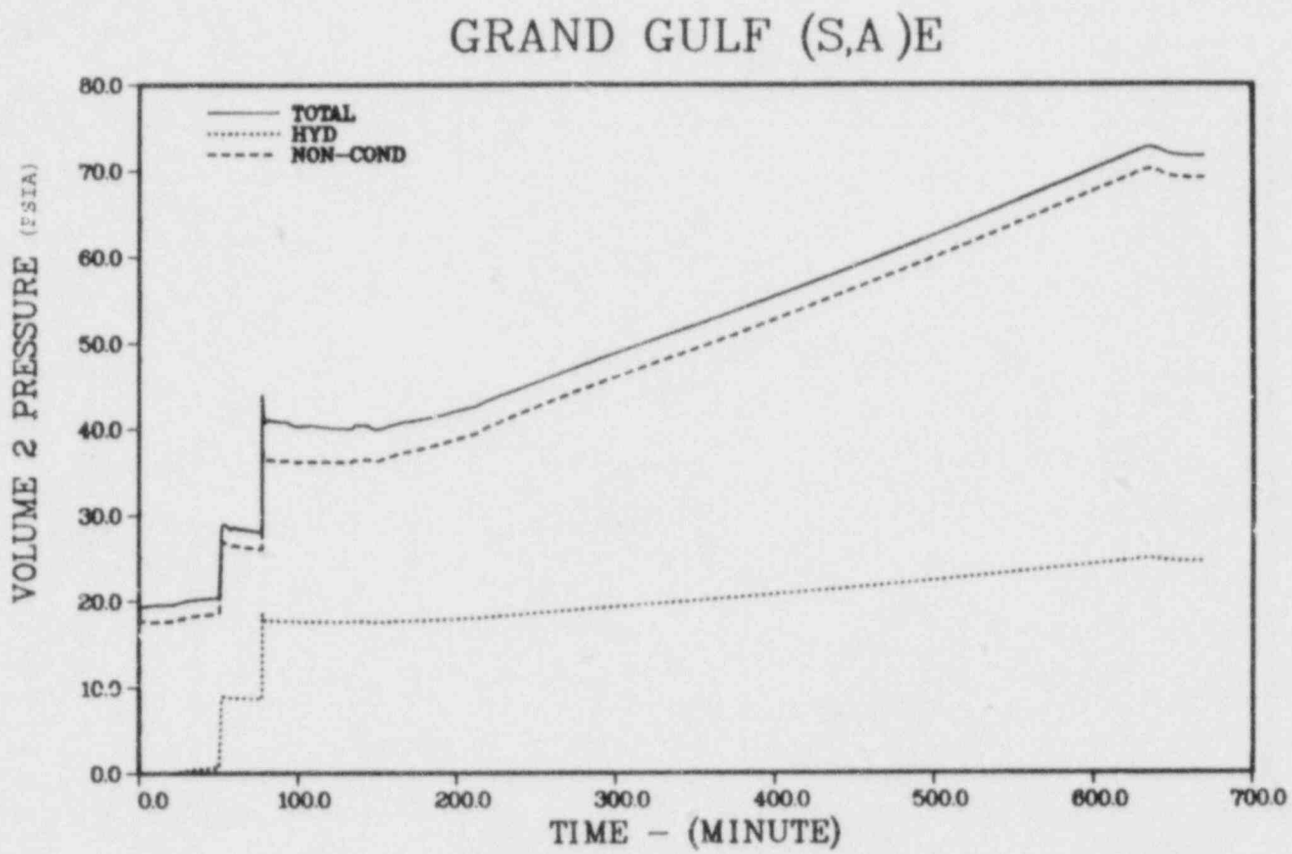

Figure C-28. Volume 2 Pressures Versus Time - SE and AE Sequences

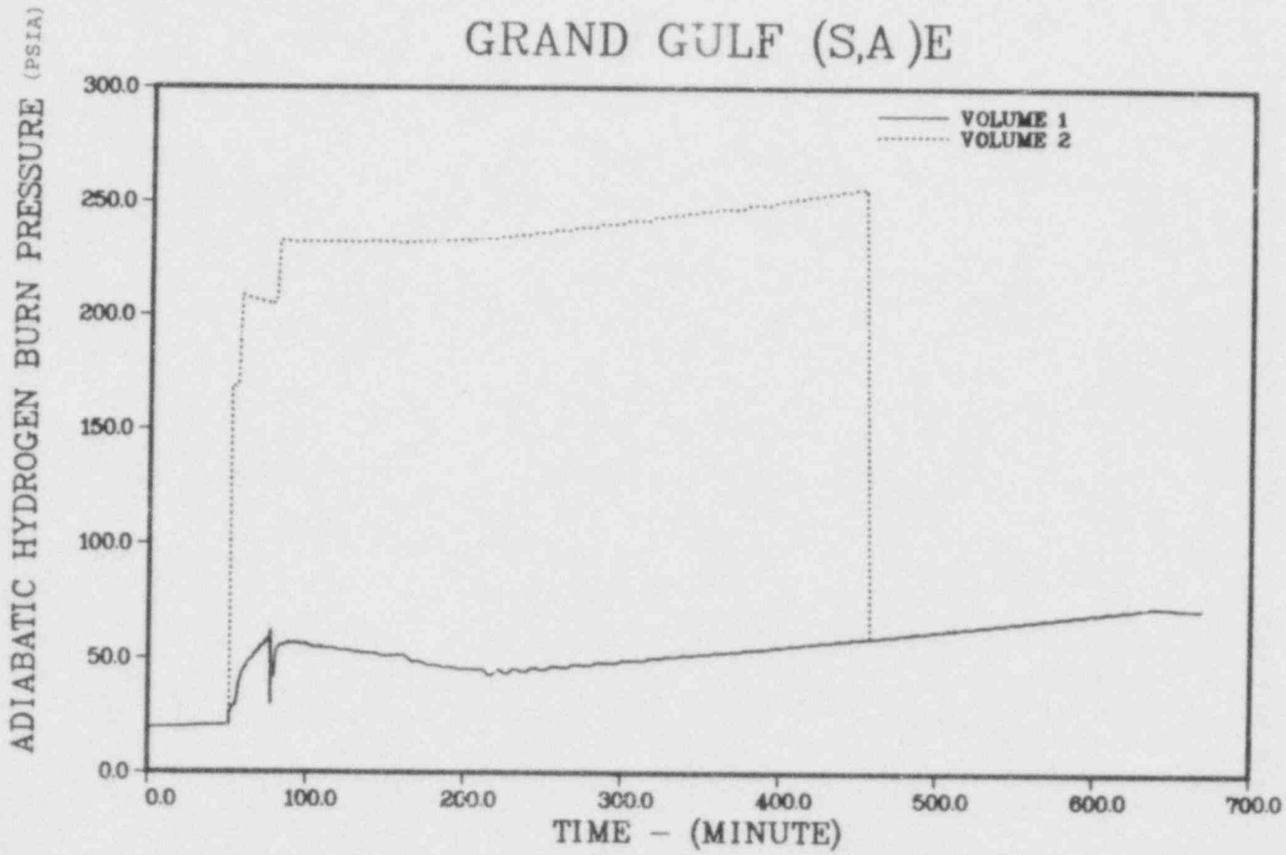

Figure C-29. Adiabatic Hydrogen Burn Pressure Versus Time - SE and AE Sequences

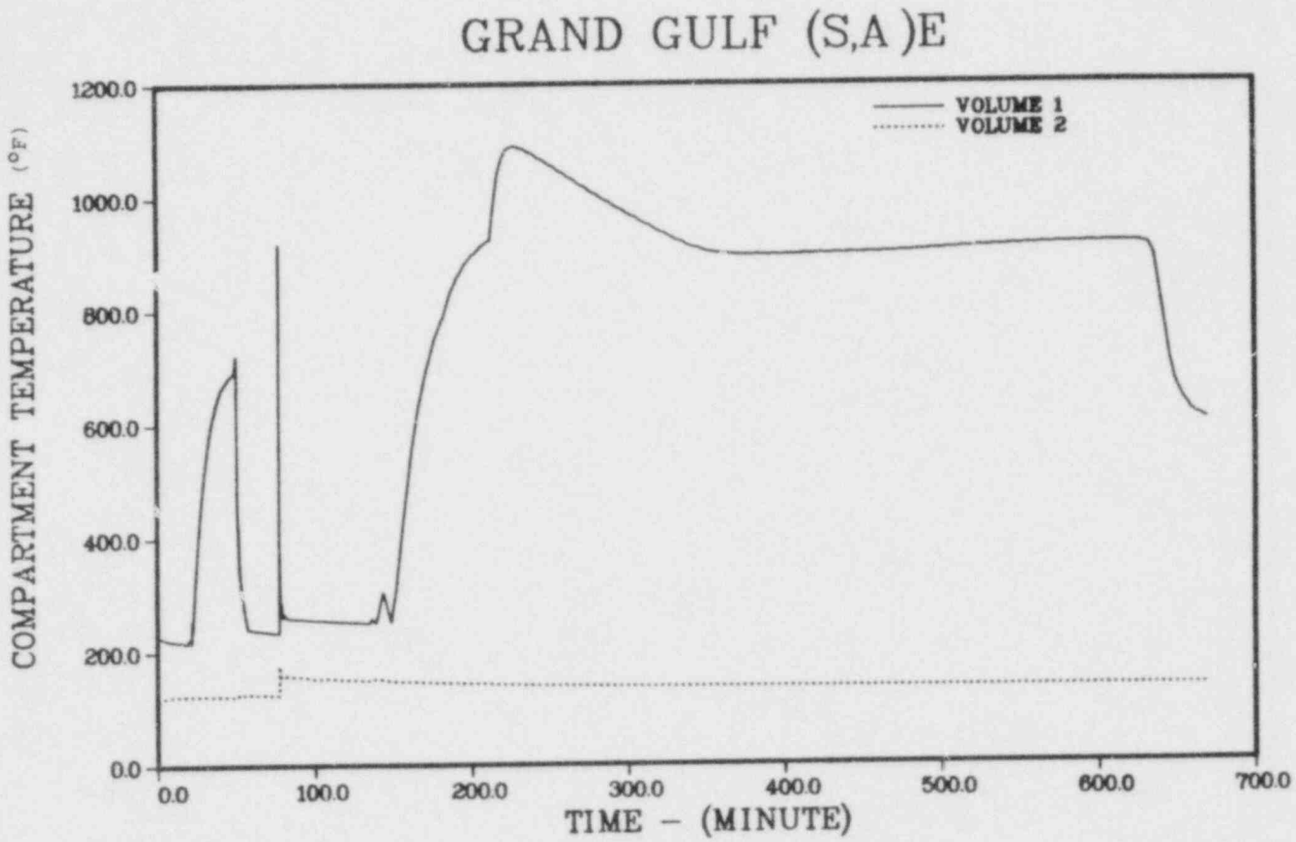

Figure C-30. Compartment Temperature Versus Time - SE and AE Sequences

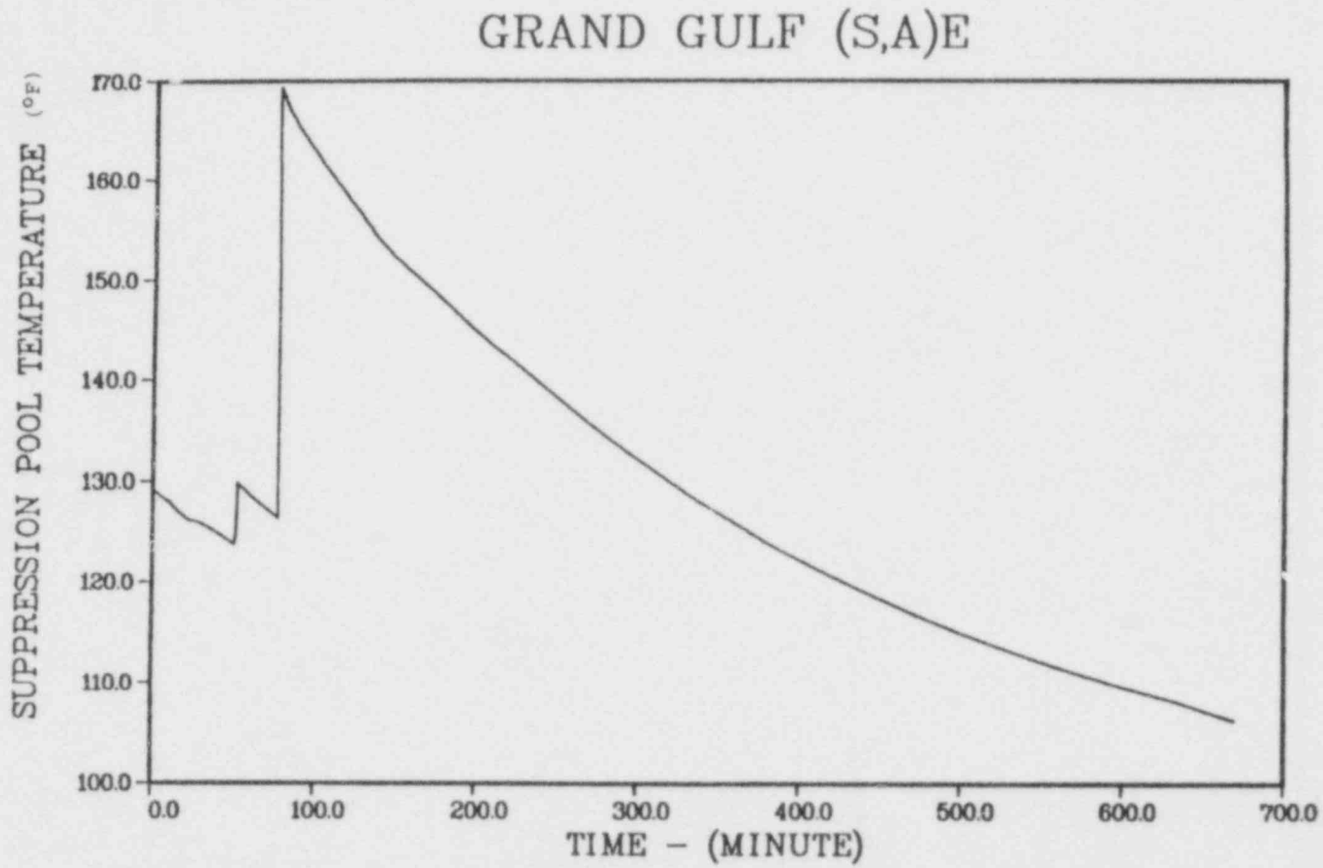

Figure C-31. Suppression Pool Temperature Versus Time - SE and AE Sequences

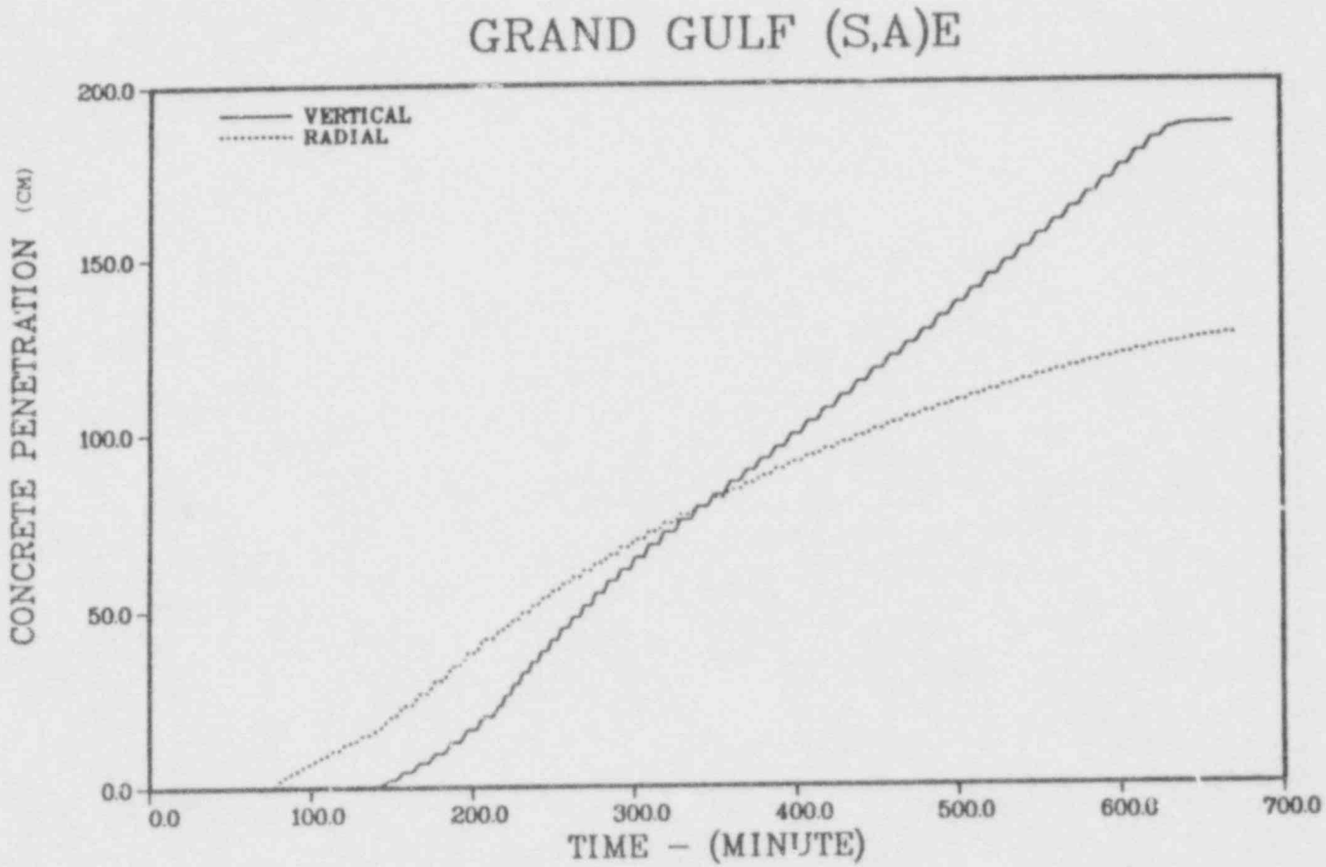

Figure C-32. Concrete Penetration Versus Time - SE and AE Sequences

APPENDIX D

CUT SETS FOR THE GRAND GULF
DOMINANT ACCIDENT SEQUENCES

The cut sets that contribute approximately 90% or more to the total of each dominant accident sequence frequency are listed below. Maintenance contributions to the cut set frequencies which would violate technical specifications have been removed when doing so will significantly affect the results. Descriptions of the cut set terms can be found in Appendices A and B.

Sequence T_1PQI

Cut Set	Frequency
T_1*P*LOPNRE*LOPNRL*DIESEL1*DIESEL2*RECOVERY	1.2×10^{-7}
T_1*P*LOPNRE*LOPNRL*VGA2*DIESEL2*RECOVERY	7.9×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGB2*DIESEL1*RECOVERY	7.9×10^{-8}
T_1*P*LOPNRE*LOPNRL*DIESEL1*SSB*RECOVERY	7.0×10^{-8}
T_1*P*LOPNRE*LOPNRL*DIESEL2*SSA*RECOVERY	7.0×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA2*VGB2*RECOVERY	5.3×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA1*DIESEL2*RECOVERY	5.0×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGB1*DIESEL1*RECOVERY	5.0×10^{-8}
T_1*P*LOPNRE*LOPNRL*SB*DIESEL1*RECOVERY	4.6×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA2*SSB*RECOVERY	4.6×10^{-8}
T_1*P*LOPNRE*LOPNRL*LA2*DIESEL2*RECOVERY	4.6×10^{-8}
T_1*P*LOPNRE*LOPNRL*SA*DIESEL2*RECOVERY	4.6×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGB2*SSA*RECOVERY	4.6×10^{-8}
T_1*P*LOPNRE*LOPNRL*LB2*DIESEL1*RECOVERY	4.6×10^{-8}
T_1*P*LOPNRE*LOPNRL*SSA*SSB*RECOVERY	4.1×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA1*VGB2*RECOVERY	3.3×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA2*VGB1*RECOVERY	3.3×10^{-8}
T_1*P*LOPNRE*LOPNRL*LA2*VGB2*RECOVERY	3.1×10^{-8}
T_1*P*LOPNRE*LOPNRL*LB2*VGA2*RECOVERY	3.1×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA1*SSB*RECOVERY	2.9×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGB1*SSA*RECOVERY	2.9×10^{-8}
T_1*P*LOPNRE*LOPNRL*LA2*SSB*RECOVERY	2.7×10^{-8}
T_1*P*LOPNRE*LOPNRL*SA*SSB*RECOVERY	2.7×10^{-8}
T_1*P*LOPNRE*LOPNRL*SB*SSA*RECOVERY	2.7×10^{-8}
T_1*P*LOPNRE*LOPNRL*LB2*SSA*RECOVERY	2.7×10^{-8}
T_1*P*LOPNRE*LOPNRL*DIESEL1*V2*RECOVERY	2.6×10^{-8}
T_1*P*LOPNRE*LOPNRL*DIESEL2*V1*RECOVERY	2.6×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA1*VGB1*RECOVERY	2.1×10^{-8}
T_1*P*LOPNRE*LOPNRL*LA2*VGB1*RECOVERY	1.9×10^{-8}
T_1*P*LOPNRE*LOPNRL*LB2*VGA1*RECOVERY	1.9×10^{-8}
T_1*P*LOPNRE*LOPNRL*SA*SB*RECOVERY	1.8×10^{-8}
T_1*P*LOPNRE*LOPNRL*LA2*LB2*RECOVERY	1.8×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA2*V2*RECOVERY	1.8×10^{-8}

Cut Set	Frequency
T_1*P*LOPNRE*LOPNRL*VGB2*V1*RECOVERY	1.8×10^{-8}
T_1*P*LOPNRE*LOPNRL*SSA*V2*RECOVERY	1.5×10^{-8}
T_1*P*LOPNRE*LOPNRL*SSB*V1*RECOVERY	1.5×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGA1*V2*RECOVERY	1.1×10^{-8}
T_1*P*LOPNRE*LOPNRL*VGB1*V1*RECOVERY	1.1×10^{-8}
T_1*P*LOPNRE*LOPNRL*LA2*V2*RECOVERY	1.0×10^{-8}
T_1*P*LOPNRE*LOPNRL*SA*V2*RECOVERY	1.0×10^{-8}
T_1*P*LOPNRE*LOPNRL*SB*V1*RECOVERY	1.0×10^{-8}
T_1*P*LOPNRE*LOPNRL*LB2*V1*RECOVERY	1.0×10^{-8}
T_1*P*LOPNRE*LOPNRL*V1*V2*RECOVERY	5.9×10^{-9}

Sequence T_{23}PQI

T_{23}*P*Q*VGA2*VGB2*RECOVERY	5.0×10^{-7}
T_{23}*P*Q*VGB2*SSA*RECOVERY	3.4×10^{-7}
T_{23}*P*Q*VGA2*SSB*RECOVERY	3.4×10^{-7}
T_{23}*P*Q*VGA2*VGB1*RECOVERY	2.5×10^{-7}
T_{23}*P*Q*VGA1*VGB2*RECOVERY	2.5×10^{-7}
T_{23}*P*Q*VGA2*LB2*RECOVERY	2.3×10^{-7}
T_{23}*P*Q*VGB2*LA2*RECOVERY	2.3×10^{-7}
T_{23}*P*Q*SSA*SSB*RECOVERY	1.6×10^{-7}
T_{23}*P*Q*VGB1*SSA*RECOVERY	1.3×10^{-7}
T_{23}*P*Q*VGA1*SSB*RECOVERY	1.3×10^{-7}
T_{23}*P*Q*LB2*SSA*RECOVERY	1.0×10^{-7}
T_{23}*P*Q*LA2*SSB*RECOVERY	1.0×10^{-7}
T_{23}*P*Q*VGA1*VGB1*RECOVERY	1.0×10^{-7}
T_{23}*P*Q*VGA1*LB2*RECOVERY	8.5×10^{-8}
T_{23}*P*Q*VGB1*LA2*RECOVERY	8.5×10^{-8}
T_{23}*P*Q*SA*SB*RECOVERY	6.9×10^{-8}
T_{23}*P*Q*LA2*LB2*RECOVERY	6.9×10^{-8}
T_{23}*P*Q*VGA2*SBC*RECOVERY	3.2×10^{-8}
T_{23}*P*Q*VGA2*BCACT*RECOVERY	3.2×10^{-8}
T_{23}*P*Q*VGB2*SAC*RECOVERY	3.2×10^{-8}
T_{23}*P*Q*VGB2*LRACT*RECOVERY	3.2×10^{-8}
T_{23}*P*Q*SAC*SSB*RECOVERY	2.8×10^{-8}
T_{23}*P*Q*SSB*LRACT*RECOVERY	2.8×10^{-8}
T_{23}*P*Q*SBC*SSA*RECOVERY	2.8×10^{-8}
T_{23}*P*Q*SSA*BCACT*RECOVERY	2.8×10^{-8}
T_{23}*P*Q*PA27*VGB2*RECOVERY	2.2×10^{-8}
T_{23}*P*Q*PB27*VGA2*RECOVERY	2.2×10^{-8}
T_{23}*P*Q*VGA1*BCACT*RECOVERY	2.0×10^{-8}
T_{23}*P*Q*VGA1*SBC*RECOVERY	2.0×10^{-8}
T_{23}*P*Q*LRACT*VGB1*RECOVERY	2.0×10^{-8}
T_{23}*P*Q*VGB1*SAC*RECOVERY	2.0×10^{-8}
T_{23}*P*Q*PA27*SSB*RECOVERY	1.9×10^{-8}
T_{23}*P*Q*PB27*SSA*RECOVERY	1.9×10^{-9}
T_{23}*P*Q*SAACC*SB*RECOVERY	1.9×10^{-8}
T_{23}*P*Q*LRACT*LB2*RECOVERY	1.9×10^{-8}
T_{23}*P*Q*LA2*SBC*RECOVERY	1.9×10^{-8}
T_{23}*P*Q*LB2*SAC*RECOVERY	1.9×10^{-8}
T_{23}*P*Q*LA2*BCACT*RECOVERY	1.9×10^{-8}
T_{23}*P*Q*SA*SBACC*RECOVERY	1.9×10^{-8}

Sequence T_1PQE

Cut Set	Frequency
T_1*P*Q*OP*H*R	1.1×10^{-8}
T_1*P*Q*OP*LOPNRE*DIESEL3*R	1.1×10^{-8}
T_1*P*Q*LOPNRE*DIESEL1*DIESEL2*DIESEL3*R	9.5×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*DIESEL3*R*LC	5.8×10^{-9}
T_1*P*Q*LOPNRE*DIESEL2*DIESEL3*L*R	5.6×10^{-9}
T_1*P*Q*LOPNRE*SSA*DIESEL2*DIESEL3*R	5.6×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*DIESEL2*H*R	5.6×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*SSB*DIESEL3*R	5.6×10^{-9}
T_1*P*Q*LOPNRE*BATA*DIESEL2*DIESEL3	5.2×10^{-9}
T_1*P*Q*OP*LOPNRE*SSC*R	4.3×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*DIESEL2*SSC*R	3.7×10^{-9}
T_1*P*Q*LOPNRE*LB2*DIESEL1*DIESEL3*R	3.7×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*DIESEL3*R*LB1	3.4×10^{-9}
T_1*P*Q*LOPNRE*SSA*DIESEL3*R*LC	3.4×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*H*R*LC	3.4×10^{-9}
T_1*P*Q*LOPNRE*SSB*DIESEL3*L*R	3.2×10^{-9}
T_1*P*Q*LOPNRE*L*H*R*DIESEL2	3.2×10^{-9}
T_1*P*Q*LOPNRE*SSA*DIESEL2*H*R	3.2×10^{-9}
T_1*P*Q*LOPNRE*SSA*SSB*DIESEL3*R	3.2×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*SSB*H*R	3.2×10^{-9}
T_1*P*Q*BATA*LOPNRE*DIESEL3*LC	3.2×10^{-9}
T_1*P*Q*BATA*LOPNRE*DIESEL2*H	3.0×10^{-9}
T_1*P*Q*BATA*LOPNRE*SSB*DIESEL3	3.0×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*SSC*R*LC	2.3×10^{-9}
T_1*P*Q*LOPNRE*DIESEL2*SSC*L*R	2.2×10^{-9}
T_1*P*Q*LOPNRE*SSA*DIESEL2*SSC*R	2.2×10^{-9}
T_1*P*Q*LOPNRE*LB2*SSA*DIESEL3*R	2.2×10^{-9}
T_1*P*Q*LOPNRE*LB2*DIESEL1*H*R	2.2×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*SSB*SSC*R	2.2×10^{-9}
T_1*P*Q*LOPNRE*V1*DIESEL2*DIESEL3*R	2.1×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*V2*DIESEL3*R	2.1×10^{-9}
T_1*P*Q*BATA*LOPNRE*DIESEL2*SSC	2.0×10^{-9}
T_1*P*Q*BATA*LOPNRE*LB2*DIESEL3	2.0×10^{-9}
T_1*P*Q*LOPNRE*SSA*DIESEL3*R*LB1	2.0×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*H*R*LB1	2.0×10^{-9}
T_1*P*Q*LOPNRE*SSA*H*R*LC	2.0×10^{-9}
T_1*P*Q*LOPNRE*SSB*L*H*R	1.9×10^{-9}
T_1*P*Q*LOPNRE*SSA*SSB*H*R	1.9×10^{-9}
T_1*P*Q*BATA*LOPNRE*DIESEL3*LB1	1.9×10^{-9}
T_1*P*Q*OP*HACT*R	1.8×10^{-9}
T_1*P*Q*BATA*LOPNRE*H*LC	1.8×10^{-9}
T_1*P*Q*BATA*LOPNRE*SSB*H	1.8×10^{-9}
T_1*P*Q*LOPNRE*LB2*DIESEL1*SSC*R	1.4×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*SSC*R*LB1	1.3×10^{-9}
T_1*P*Q*LOPNRE*SSA*SSC*R*LC	1.3×10^{-9}
T_1*P*Q*LOPNRE*V1*DIESEL3*R*LC	1.3×10^{-9}
T_1*P*Q*LOPNRE*SSB*SSC*L*R	1.3×10^{-9}
T_1*P*Q*LOPNRE*LB2*SSA*H*R	1.3×10^{-9}
T_1*P*Q*LOPNRE*SSA*SSB*SSC*R	1.3×10^{-9}
T_1*P*Q*LOPNRE*V2*DIESEL3*L*R	1.2×10^{-9}
T_1*P*Q*LOPNRE*SSA*V2*DIESEL3*R	1.2×10^{-9}

Cut Set	Frequency
T_1*P*Q*LOPNRE*V1*DIESEL2*H*R	1.2×10^{-9}
T_1*P*Q*LOPNRE*V1*SSB*DIESEL3*R	1.2×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*V2*H*R	1.2×10^{-9}
T_1*P*Q*BATA*LOPNRE*SSC*LC	1.2×10^{-9}
T_1*P*Q*BATA*LOPNRE*SSB*SSC	1.2×10^{-9}
T_1*P*Q*BATA*LOPNRE*LB2*H	1.2×10^{-9}
T_1*P*Q*LOPNRE*SSA*H*R*LB1	1.2×10^{-9}
T_1*P*Q*BATA*LOPNRE*V2*DIESEL3	1.2×10^{-9}
T_1*P*Q*BATA*LOPNRE*H*LB1	1.1×10^{-9}
T_1*P*Q*LOPNRE*DIESEL1*DIESEL2*V3*R	8.7×10^{-10}
T_1*P*Q*LOPNRE*LB2*SSA*SSC*R	8.4×10^{-10}
T_1*P*Q*LOPNRE*V1*DIESEL2*SSC*R	8.2×10^{-10}
T_1*P*Q*LOPNRE*LB2*V1*DIESEL3*R	8.2×10^{-10}
T_1*P*Q*LOPNRE*DIESEL1*V2*SSC*R	8.2×10^{-10}
T_1*P*Q*BATA*LOPNRE*LB2*SSC	7.8×10^{-10}
T_1*P*Q*LOPNRE*SSA*SSC*R*LB1	7.8×10^{-10}
T_1*P*Q*LOPNRE*V1*DIESEL3*R*LB1	7.6×10^{-10}
T_1*P*Q*LOPNRE*V1*H*R*LC	7.5×10^{-10}
T_1*P*Q*BATA*LOPNRE*SSC*LB1	7.3×10^{-10}
T_1*P*Q*LOPNRE*V2*L*H*R	7.2×10^{-10}
T_1*P*Q*LOPNRE*SSA*V2*H*R	7.2×10^{-10}
T_1*P*Q*LOPNRE*V1*SSB*H*R	7.2×10^{-10}
T_1*P*Q*BATA*LOPNRE*V2*H	6.7×10^{-10}
T_1*P*Q*LRACT*H*R*LC	5.7×10^{-10}
T_1*P*Q*BCACT*L*H*R	5.4×10^{-10}
T_1*P*Q*LOPNRE*DIESEL1*V3*R*LC	5.3×10^{-10}
T_1*P*Q*LOPNRE*DIESEL2*V3*L*R	5.1×10^{-10}
T_1*P*Q*LOPNRE*SSA*DIESEL2*V3*R	5.1×10^{-10}
T_1*P*Q*LOPNRE*DIESEL1*SSB*V3*R	5.1×10^{-10}
T_1*P*Q*LOPNRE*V1*SSC*R*LC	5.0×10^{-10}
T_1*P*Q*LOPNRE*V2*SSC*L*R	4.8×10^{-10}
T_1*P*Q*LOPNRE*SSA*V2*SSC*R	4.8×10^{-10}
T_1*P*Q*LOPNRE*LB2*V1*H*R	4.8×10^{-10}
T_1*P*Q*LOPNRE*V1*SSB*SSC*R	4.8×10^{-10}
T_1*P*Q*BATA*LOPNRE*DIESEL2*V3	4.8×10^{-10}
Sequence T_{23}PQE	
T_{23}*P*Q*OP*R*H	3.8×10^{-7}
T_{23}*P*Q*OP*R*HACT	6.4×10^{-8}
T_{23}*P*Q*OP*RACT*H	2.6×10^{-8}
T_{23}*P*Q*R*LRACT*H*LC	2.0×10^{-8}
T_{23}*P*Q*R*BCACT*L*H	1.9×10^{-8}
T_{23}*P*Q*R*LRACT*LB2*H	1.3×10^{-8}
T_{23}*P*Q*R*LRACT*H*LB1	1.2×10^{-8}
Sequence SI	
S*VGA2*VGB2	6.2×10^{-7}
S*VGB2*SSA	4.2×10^{-7}
S*VGA2*SSB	4.2×10^{-7}
S*VGA2*VGB1	3.2×10^{-7}
S*VGA1*VGB2	3.2×10^{-7}
S*VGA2*LB2	2.8×10^{-7}

Cut Set	Frequency
S*LA2*VGB2	2.8×10^{-7}
S*SSA*SSB	1.9×10^{-7}
S*VGB1*SSA	1.6×10^{-7}
S*VGA1*SSB	1.6×10^{-7}
S*LB2*SSA	1.3×10^{-7}
S*LA2*SSB	1.3×10^{-7}
S*VGA1*VGB1	1.3×10^{-7}
S*VGA1*LB2	1.1×10^{-7}
S*LA2*VGB1	1.1×10^{-7}
S*SA*SB	8.6×10^{-8}
S*LA2*LB2	8.6×10^{-8}
S*VGA2*SBC	4.0×10^{-8}
S*VGA2*BCACT	4.0×10^{-8}
S*VGB2*SAC	4.0×10^{-8}
S*VGB2*LRACT	4.0×10^{-8}
S*SAC*SSB	3.5×10^{-8}
S*LRACT*SSB	3.5×10^{-8}
S*SSA*SBC	3.5×10^{-8}
S*BCACT*SSA	3.5×10^{-8}
S*PA27*VGB2	2.7×10^{-8}
S*VGA2*PB27	2.7×10^{-8}
S*VGA1*BCACT	2.5×10^{-8}
S*VGA1*SBC	2.5×10^{-8}
S*LRACT*VGB1	2.5×10^{-8}
S*VGB1*SAC	2.5×10^{-8}
S*PA27*SSB	2.4×10^{-8}
S*PB27*SSA	2.4×10^{-8}
S*SAACC*SB	2.4×10^{-8}
S*LRACT*LB2	2.4×10^{-8}
S*LA2*SBC	2.4×10^{-8}
S*LB2*SAC	2.4×10^{-8}
S*LA2*BCACT	2.4×10^{-8}
S*SA*SBACC	2.4×10^{-8}

Sequence T_1QW

T_1*LOPNRE*LOPNRL*DIESEL1*DIESEL2*RECOVERY	1.1×10^{-6}
T_1*LOPNRE*LOPNRL*SSA*DIESEL2*RECOVERY	6.4×10^{-7}
T_1*LOPNRE*LOPNRL*DIESEL1*SSB*RECOVERY	6.4×10^{-7}
T_1*LOPNRE*LOPNRL*VGB1*DIESEL1*RECOVERY	4.5×10^{-7}
T_1*LOPNRE*LOPNRL*VGA1*DIESEL2*RECOVERY	4.5×10^{-7}
T_1*LOPNRE*LOPNRL*SSA*SSB*RECOVERY	3.7×10^{-7}
T_1*LOPNRE*LOPNRL*VGB1*SSA*RECOVERY	2.6×10^{-7}
T_1*LOPNRE*LOPNRL*VGA1*SSB*RECOVERY	2.6×10^{-7}
T_1*LOPNRE*LOPNRL*V1*DIESEL2*RECOVERY	2.4×10^{-7}
T_1*LOPNRE*LOPNRL*DIESEL1*V2*RECOVERY	2.4×10^{-7}
T_1*LOPNRE*LOPNRL*VGA1*VGB1*RECOVERY	1.9×10^{-7}
T_1*LOPNRE*LOPNRL*SSA*V2*RECOVERY	1.4×10^{-7}
T_1*LOPNRE*LOPNRL*V1*SSB*RECOVERY	1.4×10^{-7}
T_1*LOPNRE*LOPNRL*VGB1*V1*RECOVERY	1.0×10^{-7}
T_1*LOPNRE*LOPNRL*VGA1*V2*RECOVERY	1.0×10^{-7}
T_1*LOPNRE*LOPNRL*V1*V2*RECOVERY	5.4×10^{-8}
T_1*LOPNRE*LOPNRL*VGA2*DIESEL2*R*RECOVERY	3.7×10^{-8}

Cut Set	Frequency
T_1*LOPNRE*LOPNRL*VGB2*DIESEL1*R*RECOVERY	3.7×10^{-8}
T_1*LOPNRE*LOPNRL*SAC*DIESEL2*RECOVERY	3.6×10^{-8}
T_1*LOPNRE*LOPNRL*DIESEL1*SBC*RECOVERY	3.6×10^{-8}
T_1*LOPNRE*LOPNRL*BATB*DIESEL1*RECOVERY	3.0×10^{-8}
T_1*LOPNRE*LOPNRL*BATA*DIESEL2*RECOVERY	3.0×10^{-8}
T_1*LOPNRE*LOPNRL*VGA2*VGB2*R*RECOVERY	2.5×10^{-8}
T_1*LOPNRE*LOPNRL*VGB2*SCVB*DIESEL1*RECOVERY	2.3×10^{-8}
T_1*LOPNRE*LOPNRL*VGA2*SCVA*DIESEL2*RECOVERY	2.3×10^{-8}
Sequence T_{23}QW	
T_{23}*Q*SSA*SSB*RECOVERY	3.2×10^{-6}
T_{23}*Q*VGB1*SSA*RECOVERY	1.9×10^{-6}
T_{23}*Q*VGA1*SSB*RECOVERY	1.9×10^{-6}
T_{23}*Q*VGA1*VGB1*RECOVERY	9.4×10^{-7}
T_{23}*Q*VGA2*VGB2*R*RECOVERY	3.0×10^{-7}
T_{23}*Q*VGA2*SSB*R*RECOVERY	2.6×10^{-7}
T_{23}*Q*VGB2*SSA*R*RECOVERY	2.6×10^{-7}
T_{23}*Q*SSA*SBC*RECOVERY	2.6×10^{-7}
T_{23}*Q*SAC*SSB*RECOVERY	2.6×10^{-7}
T_{23}*Q*VGA2*VGB1*R*RECOVERY	1.9×10^{-7}
T_{23}*Q*VGA1*VGB2*R*RECOVERY	1.9×10^{-7}
T_{23}*Q*VGB1*SAC*RECOVERY	1.9×10^{-7}
T_{23}*Q*VGA1*SBC*RECOVERY	1.9×10^{-7}
T_{23}*Q*LA2*VGB2*R*RECOVERY	1.8×10^{-7}
T_{23}*Q*VGA2*LB2*R*RECOVERY	1.8×10^{-7}
T_{23}*Q*VGB2*SCVB*SSA*RECOVERY	1.7×10^{-7}
T_{23}*Q*VGA2*SCVA*SSB*RECOVERY	1.7×10^{-7}
T_{23}*Q*LA2*SSB*R*RECOVERY	1.5×10^{-7}
T_{23}*Q*LB2*SSA*R*RECOVERY	1.5×10^{-7}
Sequence T_{23}C	
T_{23}*C	5.4×10^{-6}
Sequence T_1QUV	
T_1*LOPNRE*OP*R*DIESEL3	1.1×10^{-7}
T_1*LOPNRE*R*DIESEL1*DIESEL2*DIESEL3	9.5×10^{-8}
T_1*LOPNRE*OP*R*H	6.4×10^{-8}
T_1*LOPNRE*R*DIESEL1*DIESEL3*LC	5.8×10^{-8}
T_1*LOPNRE*R*SSA*DIESEL2*DIESEL3	5.6×10^{-8}
T_1*LOPNRE*R*DIESEL1*SSB*DIESEL3	5.6×10^{-8}
T_1*LOPNRE*R*DIESEL1*DIESEL2*H	5.6×10^{-8}
T_1*LOPNRE*R*DIESEL2*DIESEL3*L	5.6×10^{-8}
T_1*LOPNRE*BATA*DIESEL2*DIESEL3	5.2×10^{-8}
T_1*LOPNRE*OP*R*SSC	4.3×10^{-8}
T_1*LOPNRE*R*DIESEL1*DIESEL2*SSC	3.7×10^{-8}
T_1*LOPNRE*R*LB2*DIESEL1*DIESEL3	3.7×10^{-8}
T_1*LOPNRE*R*LB1*DIESEL1*DIESEL3	3.4×10^{-8}
T_1*LOPNRE*R*SSA*DIESEL3*LC	3.4×10^{-8}
T_1*LOPNRE*R*DIESEL1*H*LC	3.4×10^{-8}
T_1*LOPNRE*R*SSA*SSB*DIESEL3	3.2×10^{-8}

Cut Set	Frequency
T_1*LOPNRE*R*SSA*DIESEL2*H	3.2×10^{-8}
T_1*LOPNRE*R*SSB*DIESEL1*H	3.2×10^{-8}
T_1*LOPNRE*R*SSB*DIESEL3*L	3.2×10^{-8}
T_1*LOPNRE*R*DIESEL2*L*H	3.2×10^{-8}
T_1*LOPNRE*BATA*DIESEL3*LC	3.2×10^{-8}
T_1*LOPNRE*BATA*SSB*DIESEL3	3.0×10^{-8}
T_1*LOPNRE*BATA*DIESEL2*H	3.0×10^{-8}
T_1*LOPNRE*R*DIESEL1*SSC*LC	2.3×10^{-8}
T_1*LOPNRE*R*SSA*DIESEL2*SSC	2.2×10^{-8}
T_1*LOPNRE*R*LB2*SSA*DIESEL3	2.2×10^{-8}
T_1*LOPNRE*R*DIESEL1*SSB*SSC	2.2×10^{-8}
T_1*LOPNRE*R*LB2*DIESEL1*H	2.2×10^{-8}
T_1*LOPNRE*R*DIESEL2*SSC*L	2.2×10^{-8}
T_1*LOPNRE*R*V1*DIESEL2*DIESEL3	2.1×10^{-8}
T_1*LOPNRE*R*DIESEL1*V2*DIESEL3	2.1×10^{-8}
T_1*LOPNRE*BATA*DIESEL2*SSC	2.0×10^{-8}
T_1*LOPNRE*BATA*LB2*DIESEL3	2.0×10^{-8}
T_1*LOPNRE*R*SSA*DIESEL3*LB1	2.0×10^{-8}
T_1*LOPNRE*R*DIESEL1*H*LB1	2.0×10^{-8}
T_1*LOPNRE*R*SSA*H*LC	2.0×10^{-8}
T_1*LOPNRE*R*SSA*SSB*H	1.9×10^{-8}
T_1*LOPNRE*R*SSB*L*H	1.9×10^{-8}
T_1*LOPNRE*BATA*DIESEL3*LB1	1.9×10^{-8}
T_1*LOPNRE*BATA*H*LC	1.8×10^{-8}
T_1*LOPNRE*BATA*SSB*H	1.8×10^{-8}
T_1*LOPNRE*R*LB2*DIESEL1*SSC	1.4×10^{-8}
T_1*LOPNRE*R*DIESEL1*SSC*LB1	1.3×10^{-8}
T_1*LOPNRE*R*SSA*SSC*LC	1.3×10^{-8}
T_1*LOPNRE*R*V1*DIESEL3*LC	1.3×10^{-8}
T_1*LOPNRE*R*SSA*SSB*SSC	1.3×10^{-8}
T_1*LOPNRE*R*LB2*SSA*H	1.3×10^{-8}
T_1*LOPNRE*R*SSB*SSC*L	1.3×10^{-8}
T_1*LOPNRE*R*SSA*V2*DIESEL3	1.2×10^{-8}
T_1*LOPNRE*R*V1*SSB*DIESEL3	1.2×10^{-8}
T_1*LOPNRE*R*V1*DIESEL2*H	1.2×10^{-8}
T_1*LOPNRE*R*DIESEL1*V2*H	1.2×10^{-8}
T_1*LOPNRE*R*V2*DIESEL3*L	1.2×10^{-8}
T_1*LOPNRE*BATA*SSC*LC	1.2×10^{-8}
T_1*LOPNRE*BATA*LB2*H	1.2×10^{-8}
T_1*LOPNRE*BATA*SSB*SSC	1.2×10^{-8}
T_1*LOPNRE*R*SSA*H*LB1	1.2×10^{-8}
T_1*LOPNRE*BATA*V2*DIESEL3	1.2×10^{-8}
T_1*LOPNRE*BATA*H*LB1	1.1×10^{-8}
T_1*LOPNRE*OP*R*V3	1.0×10^{-8}
T_1*LOPNRE*R*DIESEL1*DIESEL2*V3	8.7×10^{-9}
T_1*LOPNRE*R*LB2*SSA*SSC	8.4×10^{-9}
T_1*LOPNRE*R*V1*DIESEL2*SSC	8.2×10^{-9}
T_1*LOPNRE*R*LB2*V1*DIESEL3	8.2×10^{-9}
T_1*LOPNRE*R*DIESEL1*V2*SSC	8.2×10^{-9}
T_1*LOPNRE*BATA*LB2*SSC	7.8×10^{-9}
T_1*LOPNRE*R*SSA*SSC*LB1	7.8×10^{-9}
T_1*LOPNRE*R*V1*DIESEL3*LB1	7.6×10^{-9}
T_1*LOPNRE*R*V1*H*LC	7.5×10^{-9}

Cut Set	Frequency
T_1*LOPNRE*BATA*SSC*LB1	7.3×10^{-9}
T_1*LOPNRE*R*SSA*V2*H	7.2×10^{-9}
T_1*LOPNRE*R*V1*SSB*H	7.2×10^{-9}
T_1*LOPNRE*R*V2*L*H	7.2×10^{-9}
T_1*LOPNRE*BATA*V2*H	6.7×10^{-9}
T_1*LOPNRE*R*DIESEL1*V3*LC	5.3×10^{-9}
T_1*LOPNRE*R*SSA*DIESEL2*V3	5.1×10^{-9}
T_1*LOPNRE*R*SSB*DIESEL1*V3	5.1×10^{-9}
T_1*LOPNRE*R*DIESEL2*V3*L	5.1×10^{-9}
T_1*LOPNRE*R*V1*SSC*LC	5.0×10^{-9}
T_1*LOPNRE*R*SSA*V2*SSC	4.8×10^{-9}
T_1*LOPNRE*R*V1*SSB*SSC	4.8×10^{-9}
T_1*LOPNRE*R*LB2*V1*H	4.8×10^{-9}
T_1*LOPNRE*R*V2*SSC*L	4.8×10^{-9}
T_1*LOPNRE*BATA*DIESEL2*V3	4.8×10^{-9}
T_1*LOPNRE*R*V1*V2*DIESEL3	4.7×10^{-9}
T_1*LOPNRE*BATA*V2*SSC	4.5×10^{-9}
T_1*LOPNRE*R*V1*H*LB1	4.5×10^{-9}
T_1*LOPNRE*OP*R*SCC	3.7×10^{-9}
T_1*LOPNRE*OP*R*HACT	3.7×10^{-9}
T_1*LOPNRE*R*LB2*DIESEL1*V3	3.4×10^{-9}

APPENDIX E

GLOSSARY OF ACRONYMS AND ABBREVIATIONS

ADS	Automatic Depressurization System
ANL	Argonne National Laboratories
ATWS	Anticipated Transient Without Scram
BCL	Battelle Columbus Laboratories
BWR	Boiling Water Reactor
CRDS	Control Rod Drive System
CSIS	Core Spray Injection System
CST	Condensate Storage Tank
DCPS	DC Power System
ECCS	Emergency Core Cooling System
ECI	Emergency Coolant Injection
EPS	Emergency Power System
ESF	Engineered Safety Feature
ESWS	Emergency Service Water System
FSAR	Final Safety Analysis Report
HPCIS	High Pressure Coolant Injection System
HPCS	High Pressure Core Spray
HPSWS	High Pressure Service Water System
LOCA	Loss of Coolant Accident
LOP	Loss of Offsite Power
LPCIS	Low Pressure Coolant Injection System
LPCS	Low Pressure Core Spray
LWR	Light Water Reactor
MWe	Megawatt Electrical
NRC	Nuclear Regulatory Commission

PCS	Power Conversion System
PWR	Pressurized Water Reactor
RCICS	Reactor Core Isolation Cooling System
RCS	Reactor Coolant System
RHRS	Residual Heat Removal System
RPLS	Reactor Protection Logic System
RPS	Reactor Protection System
RSS	Reactor Safety Study
RSSMAP	Reactor Safety Study Methodology Applications Program
SGTS	Standby Gas Treatment System
SNL	Sandia National Laboratories
SPMS	Suppression Pool Makeup System
S/RV	Safety/Relief Valve
SSWS	Standby Service Water System
VAC	Volts AC
VDC	Volts DC
VSS	Vapor Suppression System

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