INTERNATIONAL
TECHNOLOGY
CORPORATION

M-R470025

PROBABILISTIC ANALYSIS OF
LaSALLE COUNTY NUCLEAR POWER STATION
DIESEL GENERATOR TECHNICAL SPECIFICATION ADMENDMENT

Submitted to

COMMONWEALTH EDISON COMPANY

Prepared by

IT-DELIAN CORPORATION
One Monroeville Center, Suite 700
Monroeville, Pennsylvania 15146-2145
412/856-5700

December 15, 1987

M-R470025

PROBABILISTIC ANALYSIS OF LaSALLE COUNTY NUCLEAR POWER STATION DIESEL GENERATOR TECHNICAL SPECIFICATION ADMENDMENT

Submitted to

COMMONWEALTH EDISON COMPANY

Prepared by

IT-DELIAN CORPORATION
One Monroeville Center, Suite 700
Monroeville, Pennsylvania 15146-2145
412/856-5700

December 15, 1987

Table of Contents

Table of Contents (continued)

1.0 INTRODUCTION

This report documents the results of analyses conducted to determine the risk implication of amending the technical specification requirements for the two units of the LaSalle Nuclear Station to allow continued operation of a single unit for a period of seven days while the shared diesel generator (DG 0) is out of service to satisfy maintenance and surveillance requirements.

1.1 BACKGROUND

As an operational document, the primary goal of technical specifications is to ensure that the operation of a nuclear power plant does not pose undue risk to the general public. Though several means are commonly used to achieve this goal, the one most pertinent to this evaluation is the imposition of limiting conditions for operation (LCOs). As a means of assuring the high availability of a system during plant operation, LCOs limit the outage time of key safety system components. If a component cannot be returned to service within the allowable outage time (AOT) established by the technical specifications, the plant usually must be shut down.

Though the intent of imposing LCOs that govern the outage of key safety system components is to limit the risk to the general public from a reactor accident in which an offsite radiation release occurs, the historical basis for setting an acceptable AOT for a particular component has not been through the use of quantitative risk-based methods. Rather, establishment of appropriate AOTs has relied on engineering judgment. In the absence of a nuclear component failure rate data base, such an approach is arguably a prudent means of establishing an acceptable component outage time that balances the need to maintain the high availability of the system with the need to have a reasonable length of time to service the component without affecting plant availability.

As the nuclear power industry has accumulated operational experience, however, it has been possible to predict more accurately the reliability of individual components. With this improvement in the quality of component failure data, probabilistic risk assessments (PRAs) sponsored by both the NRC and the nuclear industry have provided insight into the risks associated with plant operation. As witnessed by their use in assessing the efficacy of implementing extensive plant design modifications, PRAs can be used as important tools in assessing the risk implications of design or procedural modifications. As a result, the recently issued "Proposed Policy Statement on Technical Specification Improvements for Nuclear Power Reactors" states that the NRC would utilize risk insights and PRAs in evaluating plant-specific submittals (1).

1.2 STUDY OBJECTIVES

In order to provide a meaningful assessment of the risk significance of the proposed extension of the AOT for the common diesel generator from three days to seven days, the following objectives must be satisfied:

- The baseline risk under the current technical specifications and the competing risk associated with a change to the AOT must be properly defined.
- The risk significance of the proposed change must be expressed in both absolute and relative terms so that informed conclusions concerning the change can be formulated.
- Engineering insights associated with plant response and system reliability must be utilized to ensure that reasonable safeguards, or restrictions to the implementation of the proposed change, have been taken to minimize the risk to the general public.

1.3 REPORT ORGANIZATION

As a prelude to discussion of the analysis, Section 2 provides an overview of the ac power distribution network at the LaSalle station. This section also examines the problems associated with the technical specification that prohibit operation of either unit if the shared diesel generator is inoperable for more than three days. The perceived cause(s) of these problems, as well as a suggested resolution, are discussed. Thus, Section 2 presents the basis for the proposed technical specification amendment and serves to define the general structure of the analysis.

With a definition of the problem(s) and a suggested resolution, it is possible to structure the analysis necessary to examine the competing risks between the two cases (i.e., before and after the proposed technical specification change). Section 3 discusses the analysis methods and structure, while the event trees used to model plant response are examined in Section 4. The results and conclusions of the analysis are presented in Sections 5 and 6, respectively.

2.0 TECHNICAL SPECIFICATION PROBLEM EVALUATION

This section focuses on the problems associated with adhering to the technical specification requirement that states that both units of the LaSalle station should be placed in cold shutdown should an outage of the common diesel generator (DG 0) exceed three days. Before evaluating the causes of the problem and attempting to devise an acceptable resolution, it is first necessary to understand the purpose and the design of the electrical power distribution system at LaSalle.

Most of the engineered safety features in nuclear power plants are extremely dependent on the availability of electric power. Within these systems, electricity is used to power pumps and valves as well as instruments and controls. Without a source of electrical power, most safety systems cannot be relied upon to perform their designed function. Consequently, the risk (i.e., the frequency of core damage or the health effects to the public) associated with a loss of offsite power (LOOP) event can be a significant contributor to the overall risk profile of a plant. Of course, the importance of such an event is dependent on a variety of plant-specific parameters such as the reliability of the offsite power grid and of the diesel generators, as well as the design and reliability of installed safety systems. Therefore, a proper evaluation of the risk implication of changes that affect the ac power system must examine the design and reliability of the ac system.

The preferred power source for all station auxiliaries at LaSalle is offsite power supplied through the switchyard. The switchyard (Figure 2-1) consists of 10 bus sections arranged in a double-ring configuration with each ring bus serving the power requirements of a single unit. Each 345 kV ring bus can be energized from one of four sources:

- o the main output transformer of the associated station when that station is operating;
- o two independent, diverse offsite 345 kV power sources; and
- o A 138 kV power line, designed for pre-operational use, which may be connected to either ring bus in the event of a loss of all other power sources.

The 138 kV Mazon/Streator line, initially installed as a second offsite power source for Unit 1, represents an offsite power supply above and beyond the standard nuclear station design requirement for two offsite power sources. As a result, the duration of a LOOP event at the LaSalle station is apt to be shorter than at comparable sites for which only the two required offsite power sources exist.

Power from the switchyard is normally supplied to each unit through the system auxiliary transformer. From the system auxiliary transformer, power to key safety systems is distributed by the three divisions of the 4.1 kV engineered safeguards features (ESF) ac system. Figure 2-2 presents a simplified schematic of the ESF ac power system for Unit 2. The distribution systems for both units of the LaSalle station are identical, so discussion of the Unit 2 system is also applicable to Unit 1.

The Division I and II buses supply loads vital to the safe shutdown of the plant in response to anticipated transients, while the Division III bus is a dedicated emergency power source for the high-pressure core spray (HPCS) system. The Division I and II buses function similarly, except that Division I shares its emergency diesel generator with the other unit. Other than this difference, each bus is provided with four power sources:

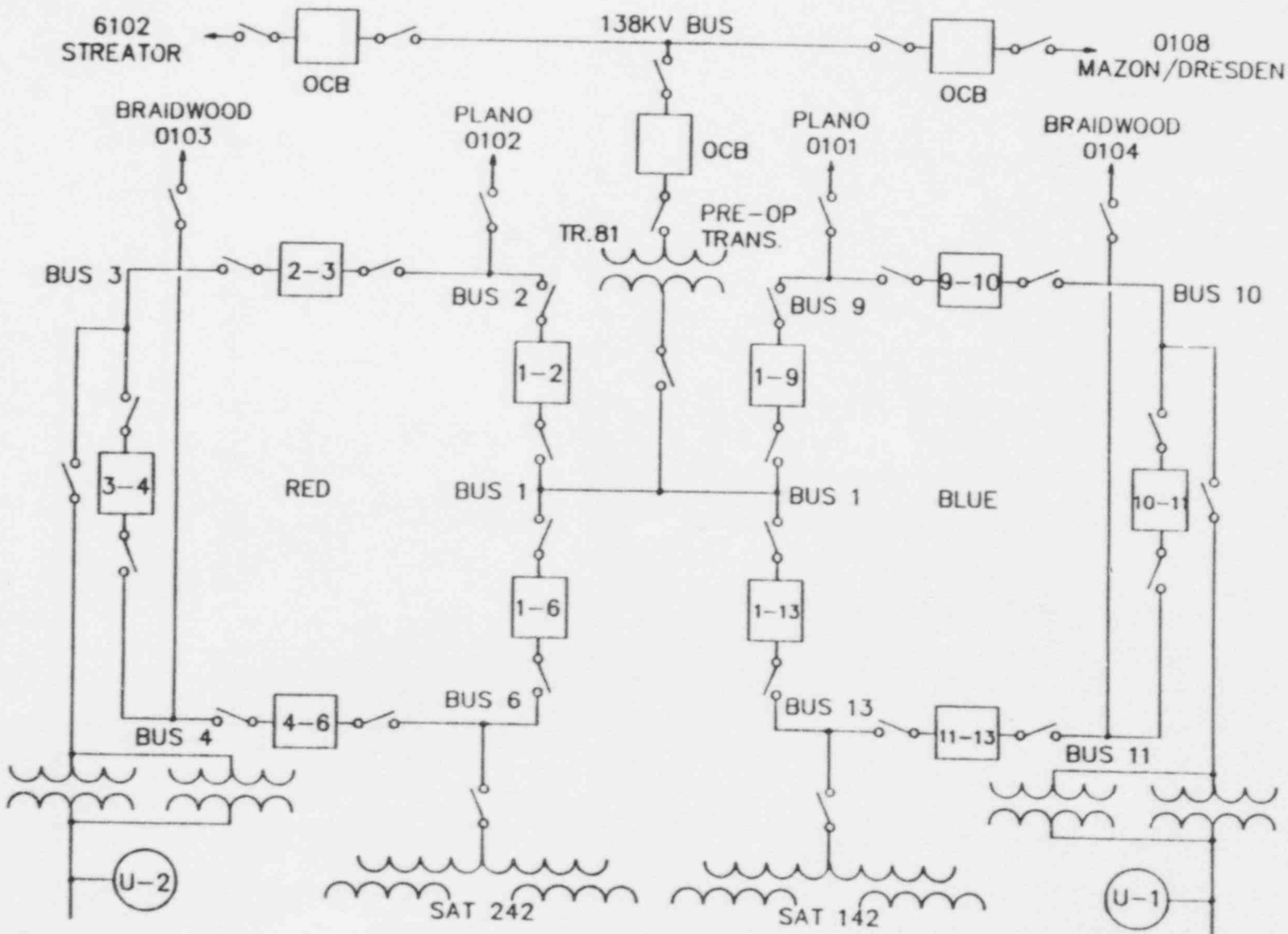


Figure 2-1 LaSalle Station Switchyard

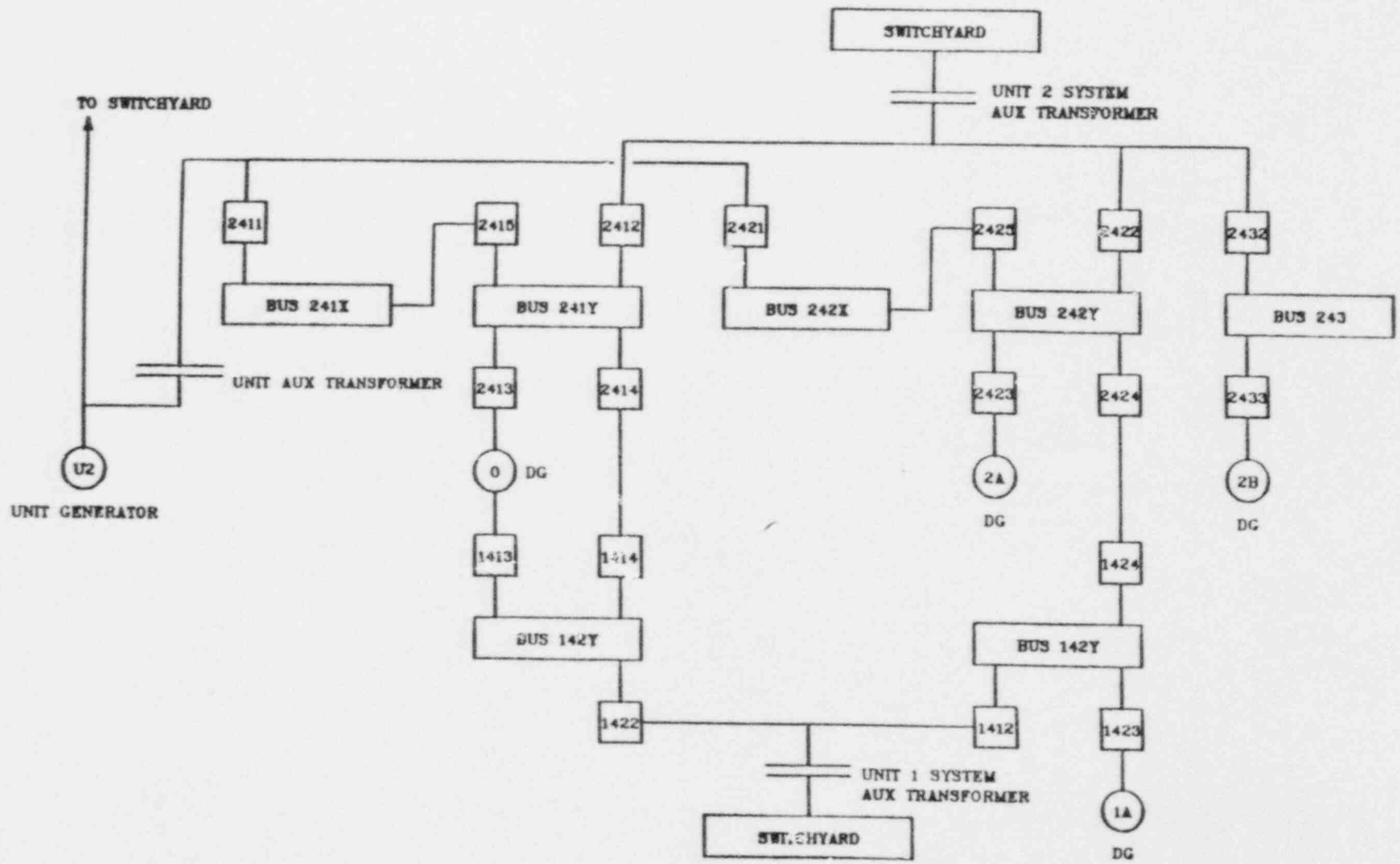


Figure 2-2 LaSalle 4kV ESF Power Distribution System

1. During normal operation, regardless of plant mode, each bus receives offsite power via the system auxiliary transformer;

2. On a loss of the normal power source, each bus automatically fast transfers to unit power via buses 241X and 242X;

3. If fast transfer to unit power fails or the unit has tripped or is not operating, an emergency diesel generator (0 or A) will automatically start and energize each bus after all loads have been shed; and

4. Should the emergency diesel power supply to either bus fail, the operator may cross-connect the bus to the corresponding Unit 1 ESF bus. It should be noted that breaker interlocks prevent this cross connection if an emergency diesel is supplying the Unit 1 bus. Since each diesel is only sized to supply the loads of a single bus, these interlocks are designed to prevent the loss of both buses in the event of a LOOP.

The Division III bus is supplied by the normal offsite source through the system auxiliary transformer with emergency power backup provided by the 2B diesel generator. As with the other diesel generators, the 2B diesel is designed to automatically start and load when a loss of power at Bus 243 is detected. Additionally, the diesel is designed to start whenever HPCS is actuated (i.e., on a reactor low-low water level or drywell high-pressure signal).

2.1 PROBLEM DESCRIPTION

According to the technical specifications, the outage of the Division I and II diesel generators shall be limited to three days. Normally, such an AOT does not present an operational burden, but the performance of routine maintenance and surveillance on the shared diesel generator (DG 0) during the refueling outage of one unit can have a significant impact on the availability of the on-line unit. While technical specification AOT requirements do not apply while a unit is in cold shutdown or refueling, the outage time restriction for DG 0 is applicable as long as one unit is operating. Hence, as discussed in more detail below, routine preventive maintenance during refueling generally will require that the operating unit be placed in cold shutdown.

On the 18-month refueling cycle, each diesel generator must be subjected to an inspection that meets the recommended preventive maintenance practices of the diesel manufacturer (Tech Spec 4.8.1.1.2d.1). Experience has shown that this inspection, which requires disassembly of the diesel, cannot be completed in the 72 hours allotted by the technical specifications of the operating unit. Also, as the diesels accumulate more run time, the number and complexity of recommended maintenance items will increase, further limiting the ability to complete all required maintenance tasks within three days.

In the past, refueling inspections of DG 0 have been performed during periods in which both units were shutdown, or the surveillance was conducted in stages (i.e., more than one outage of the diesel was required, but all outages were less than the 72 hour AOT). Performing inspections in piecemeal fashion has the potential to increase the likelihood of errors during the inspection process. Consequently, without amendment of the technical specification to extend the diesel generator AOT, CECo will opt to shutdown the operating unit before removing DG 0 from service.

In addition to the routine refueling inspection, less frequent surveillance items may further lengthen the diesel outage time. For example, once every ten years the diesel fuel oil storage tank must be drained and cleaned (Tech Spec 4.8.1.1.2f.1). Because this task cannot be completed within a 72-hour outage, it would be scheduled to coincide with the refueling inspection so that at most only one unit would be required to be shutdown.

Finally, all maintenance activities on the common diesel are complicated by the requirement that the other diesel generators for the on-line unit be started once every eight hours (Tech Spec 4.8.1.1.2a.4). Since the common diesel is removed from service to perform preplanned preventive maintenance, there is no reason to expect that the other diesels may have experienced a common mode failure. Hence, the required surveillance of the operable diesels has little effect on improving their availability. In fact, recent analyses indicate that the increased demands on the diesel generators tend to degrade their reliability (2). Furthermore, the eight-hour testing cycle for the two operable diesels burdens the operators with a distraction that diverts their attention from operation of the plant.

2.2 PROPOSED RESOLUTION

Through a review of the maintenance and surveillance requirements for DG 0, the LaSalle maintenance staff has estimated that five days will be necessary to complete all tasks. To allow for an adequate margin of error in this estimate, CECo proposes to amend the technical specification to extend the AOT for the common diesel generator to seven days. This amendment will only apply to those cases in which DG 0 has been removed from service to perform pre-planned preventive maintenance. In recognition of the importance of the availability of ac power, implementation of this amendment will be subject to the following conditions:

- One unit must be in cold shutdown, the refueling mode or defueled.
- Within 24 hours prior to removal of the 0 diesel generator from service, the diesels dedicated to the on-line unit and the Division I diesel generator (DG A) of the unit in refueling must be started and loaded onto their associated bus (Tech Spec 4.8.1.1.2a.5). Also, the alignment of the offsite power circuits for the operating unit must be verified (Tech Spec 4.8.1.1.1a).
- No maintenance of the offsite power circuits or the A and B diesel generators of the on-line unit or the A diesel generator of the unit in refueling may be performed while DG 0 is out of service.
- The control circuit for the unit cross-tie circuit breakers between buses 142Y and 242Y will be temporarily modified to allow the breakers to be closed with a diesel generator feeding one of the buses.

In the event that the above conditions cannot be satisfied, appropriate action shall be taken to place the operating unit in hot shutdown within 12 hours and cold shutdown within the following 24 hours.

2.3 EXPECTED BENEFITS

Successful resolution of the problems associated with adherence to the current three-day AOT for the common diesel generator through the implementation of the proposed amendment is expected to afford the following operational benefits:

- o Eliminate the need to shutdown an operating unit when pre-planned refueling maintenance for DG 0 is performed;
- o Decrease distractions to the operators during the outage of the shared diesel generator through a reduction in the testing requirement for the on-line unit's diesel generators; and
- o Possibly increase the reliability of the diesel generators due to fewer demands between overhauls.

A simplified economic valuation of the benefits afforded by the proposed technical specification amendment, which only considers the value of allowing continued operation of the on-line unit for five days, assesses the benefit to be $2.5M per fuel cycle (based on a replacement power cost of $500K per day).

3.0 ANALYSIS STRUCTURE

In assessing the risk impact of an amendment to the technical specifications, a baseline implicitly exists for which the fault tree and/or event tree models and data used are consistent with the requirements of the current technical specifications. Quantification of these models then represents the baseline risk, while the effect of the proposed change(s) on the baseline risk can be calculated by either modifying the baseline logic models and/or data or by developing appropriate alternate risk models. The definition and quantification of these two plant risk profiles, however, is only one aspect of the overall evaluation process. Equally important facets of the evaluation are the choice of an appropriate figure of merit to gauge the risk change and the choice of an acceptance criterion.

Though the choice of a risk measure to be used to compare the risk before and after a technical specification change can be constrained by the availability of plant-specific models and/or the modeling detail necessary to fully examine the impact of the change, the selection of a risk measure to be used in the evaluation can have a substantial influence on the conclusions drawn from the results of the analysis. For example, a technical specification change that only affects a single system or function may be examined through the use of a simple fault tree model. The use of system/functional unavailability as a figure of merit, however, has the potential to exaggerate the impact of proposed change. Without an assessment of the impact at other levels of risk (e.g., core damage frequency or public health risk), it must be conservatively assumed that any increase in unavailability results in a corresponding increase at all levels of risk. Thus, a large increase in unavailability, say 40 percent, would appear to be unacceptable. If the analysis was extended to include the effect on the total plant core damage frequency (CDF), however, it may be found that such a large system unavailability increase produces only a small increase in CDF; thus, the change may be acceptable at this level of analysis.

Similarly, the criterion used to judge the acceptability of a change in risk can also have a significant impact on the evaluation process. For example, one acceptance criterion might be that no risk increase occur as a result of the change. Such a restrictive gauge of acceptance, however, may preclude consideration of beneficial technical specification changes. To illustrate, a small increase in plant CDF (e.g., 1.0E-08) would be unacceptable if increases were not allowed, but such a change may only represent an increase in overall risk of 0.1 percent, conservatively assuming a yearly CDF of 1.0E-05. Depending on the value of the benefits to be obtained through the adoption of the proposed technical specification amendment, such a small increase in risk could be justifiable. Therefore, it is frequently necessary to examine a variety of acceptance criteria in order to better interpret the results of the analysis and formulate reasonable conclusions regarding the advisability of implementing the proposed change.

3.1 BASELINE RISK

The LaSalle maintenance staff has estimated completion of emergency diesel generator refueling inspection and maintenance will require an outage of five days; thus, under the current three-day AOT limit there is little confidence that a plant shutdown can be avoided. As a result, CECo has decided the most prudent course of action would be to shutdown the operating unit prior to removing the shared diesel generator from service. Through the avoidance of plant operation during the outage of DG 0, the incremental risk due to a LOOP event during the outage is eliminated. Therefore, the baseline risk would essentially be the core damage risk associated with plant shutdown.

Typical probabilistic analyses of shutdown risk (3,4) report the core damage frequency attributable to a manual plant shutdown to be approximately 1.0E-07. It should be noted, however, that such estimates conservatively consider the potential degradation of systems important to safe shutdown (e.g., the feedwater, power conversion, or residual heat removal systems). In developing a best estimate of shutdown risk, this approach is valid because many shutdowns are initiated by failures in these systems. For this analysis, such an estimate is not appropriate because it is known that plant shutdown occurs as a result of the impending outage of the diesel generator. Consequently, the probability of core damage due to plant shutdown would be somewhat less than 1.0E-07.

While the shutdown risk could be more precisely estimated using probabilistic models (i.e., fault and event trees), use of such an approach to develop the baseline risk has the following inherent disadvantages:

- o Due to the uncertainties associated with the use of different event tree models to calculate the baseline and competing risk and the low core damage frequency values calculated for each case, the analysis results may not be meaningful. That is, the calculated difference in core damage frequency between the two cases is apt to be within the bounds of the uncertainty.
- o The existing technical specification does not require plant shutdown to be initiated prior to removal of the shared diesel generator from service. Therefore, for licensing purposes, the permissible baseline risk should include the core damage risk associated with plant operation during the three-day allowed outage of the shared diesel generator.

To address the deficiencies associated with utilizing the shutdown risk as the baseline risk measure, an alternate approach would be to compare the risk due to a LOOP during the allowed three-day outage of DG 0 with the LOOP risk during a seven-day outage. The primary benefit of this approach is that similar probabilistic models can be used to estimate both the baseline and competing risks; hence, uncertainties due to use of different event tree models will not influence the results. Additionally, comparison of the core damage risk due to a LOOP for a three-day and a seven-day outage of the shared diesel generator permits an assessment of the effectiveness of the operating restrictions that CECo proposes to implement as a part of the technical specification change.

3.2 ALTERNATE RISK

The risk associated with amending the technical specifications to extend the AOT from three to seven days can be defined as the probability of core damage from a LOOP initiator over the seven-day outage. With the outage duration estimated to be five days, there is a high degree of confidence that a plant shutdown can be avoided. Consequently, a contribution to core damage frequency due to a manual shutdown does not need to be considered for this case. Because several restrictions govern the outage of the 0 diesel generator under the proposed technical specification amendment, the effect of these conditions must be included in the risk calculation. The possible benefits of these additional conditions can be described as follows:

- By prohibiting maintenance on the diesel generators and offsite power circuits of the operating unit during the outage of DG 0, the availability of ac power is expected to improve.
- By requiring a more thorough test of the operating unit's diesel generators (i.e., starting and loading the diesels) prior to removing the 0 diesel generator from service, the availability of the diesel generators will improve.

The benefit of imposing specific conditions on the outage of the shared diesel generator are not apparent in the construction of the LOOP event trees (see Section 4.1). Rather, these conditions have been considered in the quantification of the emergency power fault trees used to supply values for the event tree.

3.3 CONSIDERATION OF OTHER RISKS/BENEFITS

In addition to the quantifiable risk differences between the requirements of the current technical specification and those related to the amendment, there are other risks/benefits that may influence either the results of the analysis or the conclusions that may be drawn from the analysis results. These are:

- The baseline risk conservatively excludes calculation of the core damage risk associated with plant shutdown.
- There is a nontrivial risk associated with a plant in cold shutdown, as evidenced by analyses performed for the Brunswick Nuclear Station (5). In this study, the yearly contribution to core damage caused by a loss of the decay heat removal function in cold shutdown was estimated to be 5.2E-07. Even though these results may not be directly applicable to LaSalle, it must be remembered that the baseline risk encompasses more than just the risk due to a manual shutdown and/or the risk from a LOOP during the outage of the common diesel generator.
- The third offsite power source at LaSalle, as discussed in Section 2.0, would be expected to increase the capability of recovering from a loss of offsite power event. Consequently, the generic ac power recovery values used in the analysis (see Appendix B) are judged to be conservative estimates.
- Temporarily bypassing breaker interlocks that would prevent cross connection of the Division II buses on the two units if offsite power is not available may be expected to decrease the core damage frequency due to a LOOP during the AOT by an order of magnitude, assuming a human error rate of 0.1. Because the cross connection of the Unit 1 and 2 buses during a LOOP may affect the unit in refueling, this analysis has conservatively omitted consideration of this action. However, analyses show that after one week the decay heat level of the unit in refueling will be sufficiently low that cross connection of one of its buses to the operating unit will have a negligible risk impact on the unit in refueling (5).

The above items, which would tend to either increase the baseline risk or decrease the risk associated with a LOOP during the outage of the common diesel generator, cannot be explicitly quantified in the fault tree and event tree models used in this analysis. Nevertheless, in developing conclusions from the event tree analyses, the potential influence that these items may have on the results should be considered, especially if the risk difference between the three-day and seven-day AOT cases is slight.

4.0 LOSS OF OFFSITE POWER EVENT TREE MODELS

This section discusses the loss of offsite power event tree models that were developed and quantified in order to assess the impact of the proposed technical specification amendment on the risk profile of the operating unit.

During the outage of one of the two emergency diesel generators (0 or 2A), the ability of the plant to respond in the event of a LOOP is degraded. Because the Division I or Division II ESF bus must be energized to supply power to key safety systems, such as the low-pressure emergency cooling systems, failure of the operable diesel in the event of a LOOP would render these systems inoperable. The systems available in the event of such an occurrence would include the HPCS and RCIC systems with the fire protection system providing an alternate source of cooling water via the feedwater system. Even with operation of these systems, however, power must be recovered in order to establish a means of containment heat removal.

4.1 EVENT TREE MODEL DESCRIPTION

The LOOP event tree model developed for use in this analysis is presented in Figures 4-1 and 4-2, quantified for the three-day and seven-day AOT cases, respectively. The model consists of event trees that depict different time phases in the accident. To understand the necessity of developing such a model, each time phase event tree is discussed below.

Phase I (0 to 6.5 hours). With a LOOP event, the reactor will trip. To avoid core damage, coolant makeup to the vessel must be provided within 45 minutes (6). Within this short time frame, the recovery of offsite power or successful operation of the diesel (sequences 1 and 2) is considered to lead to a safe shutdown because multiple plant systems will be available to supply cooling to the reactor. Recovery probabilities for offsite power or a failed diesel generator are presented in Appendix B.

The situation in which no power is available is defined as a station blackout (SBO). Under these circumstances, the HPCS and RCIC systems would initiate on

M-R470025

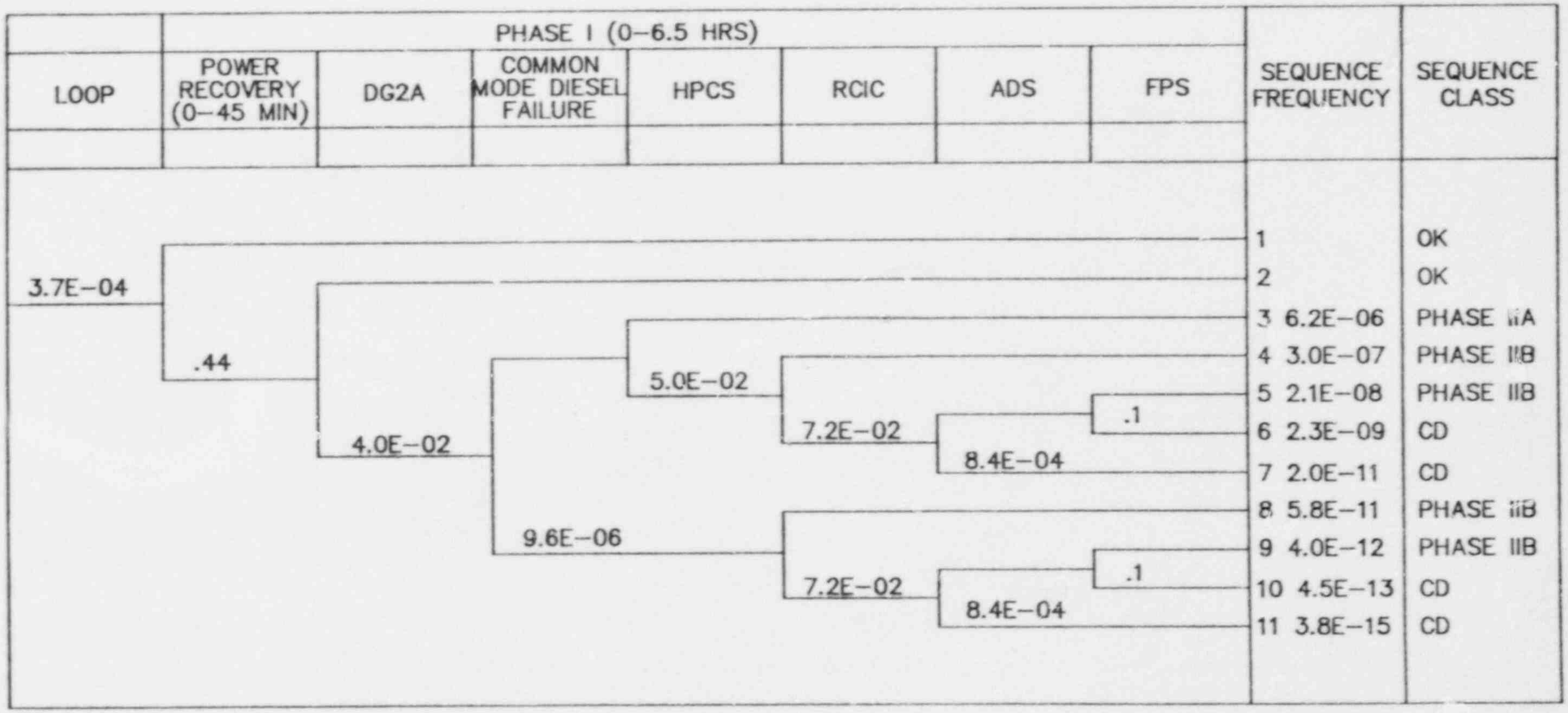
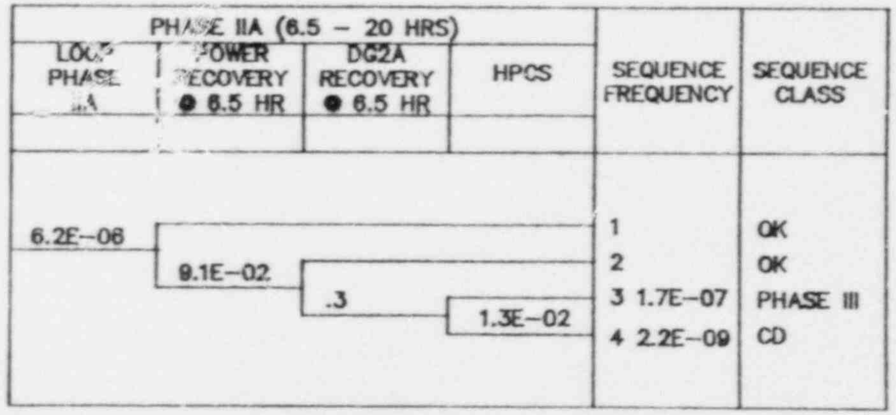


Figure 4-1

LaSalle Loss of Offsite Power Event Tree
(3-Day Allowed Outage Time)

47002531

M-R470025



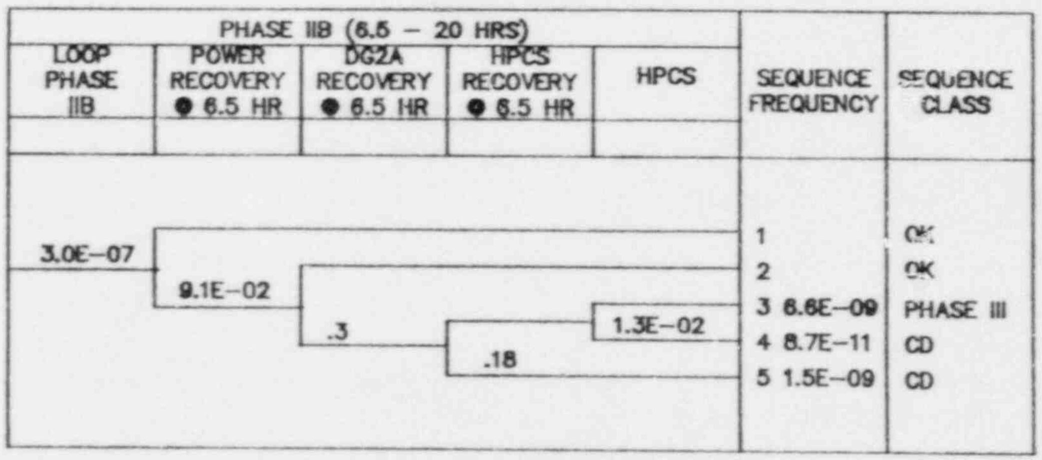


Figure 4-1 (cont'd)

LaSalle Loss of Offsite Power Event Tree
(3-Day Allowed Outage Time)

47002532

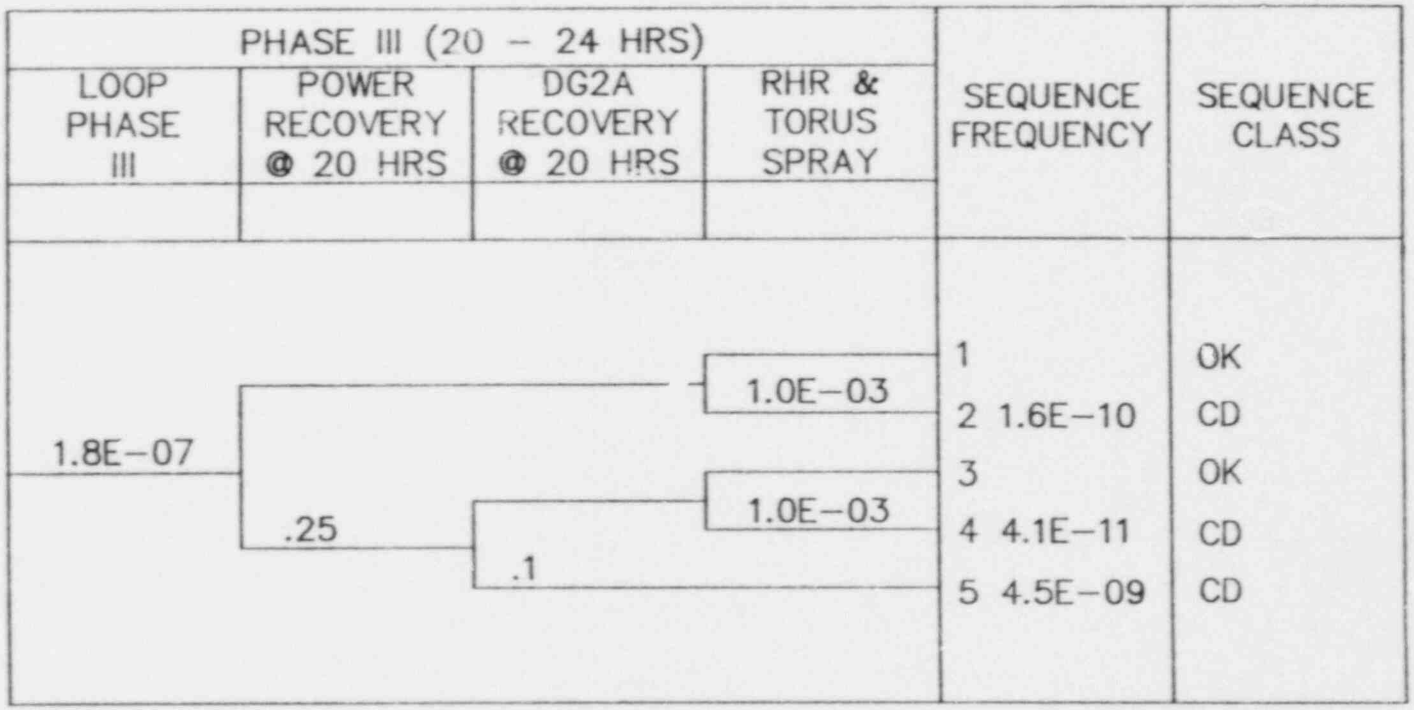


Figure 4-1 (cont'd)

LaSalle Loss of Offsite Power Event Tree
(3-Day Allowed Outage Time)

47002533

M-R470025

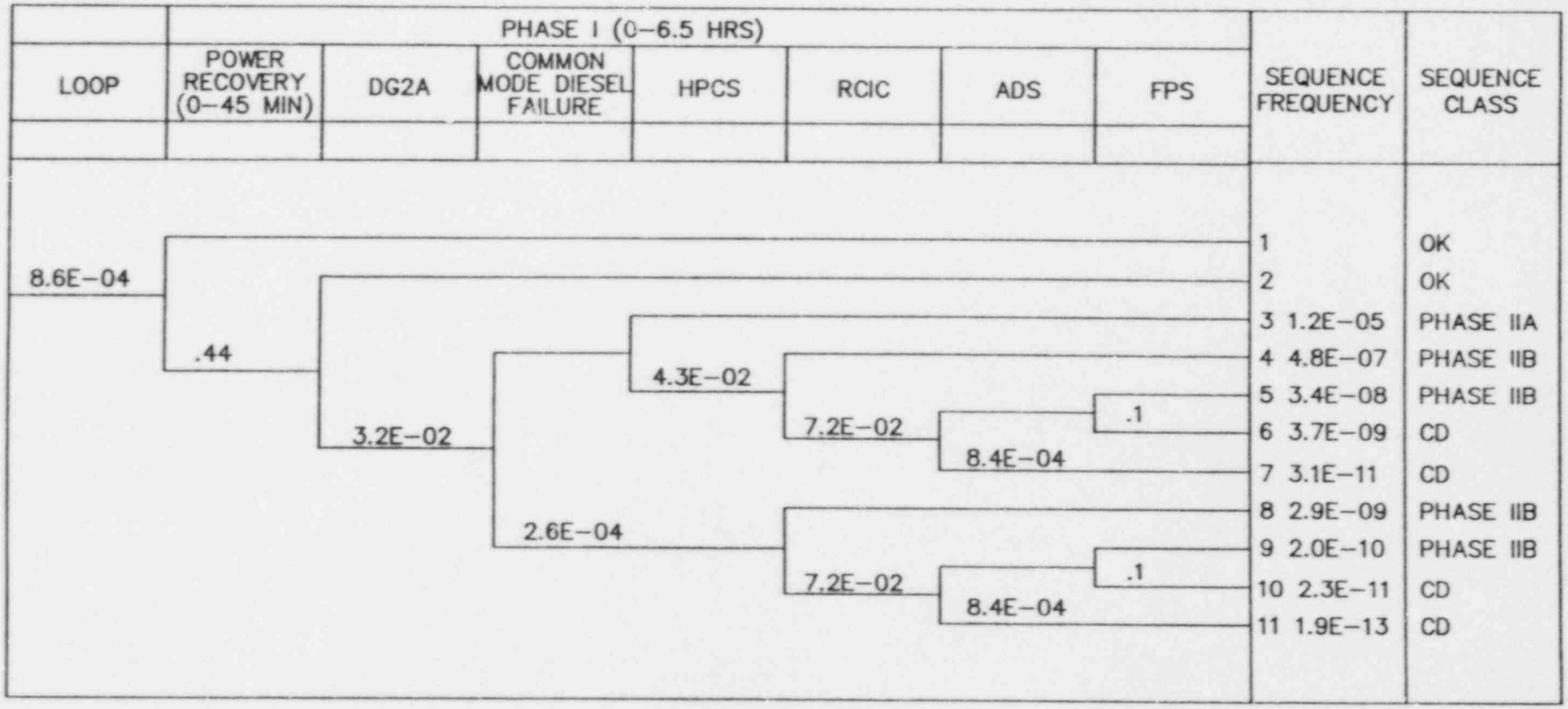
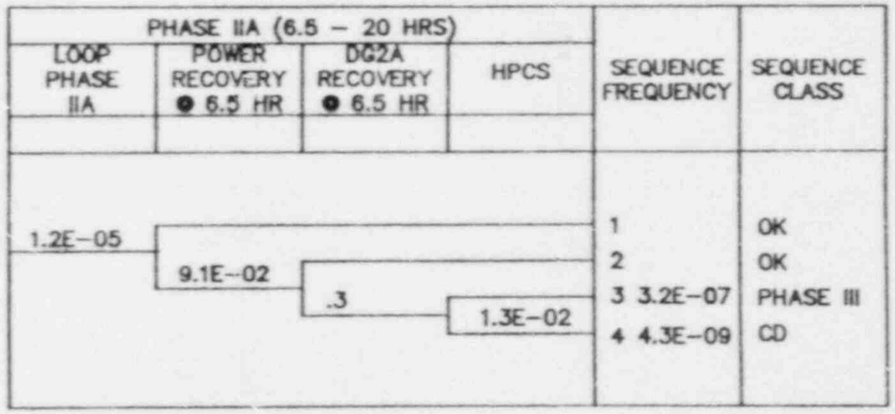


Figure 4-2

LaSalle Loss of Offsite Power Event Tree
(7-Day Allowed Outage Time)

47002571

M-R470025



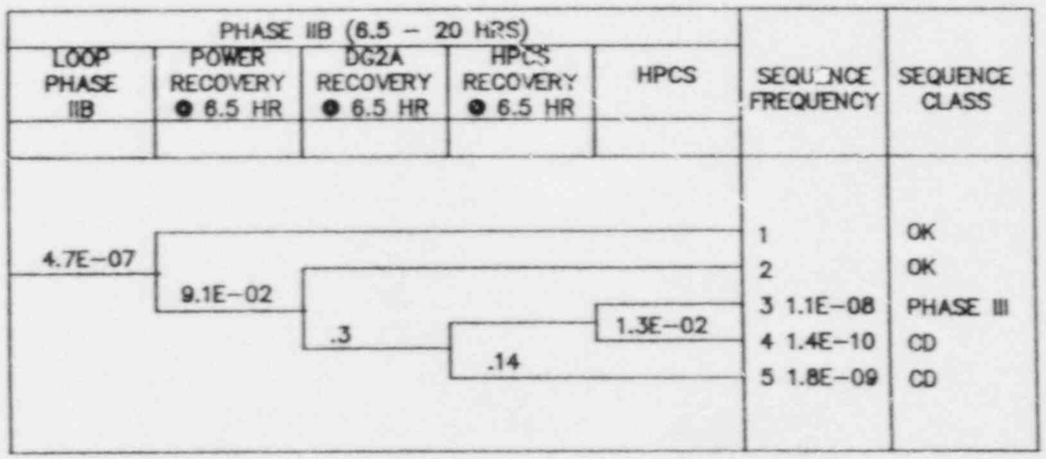


Figure 4-2 (cont'd)

LaSalle Loss of Offsite Power Event Tree
(7-Day Allowed Outage Time)

47002572

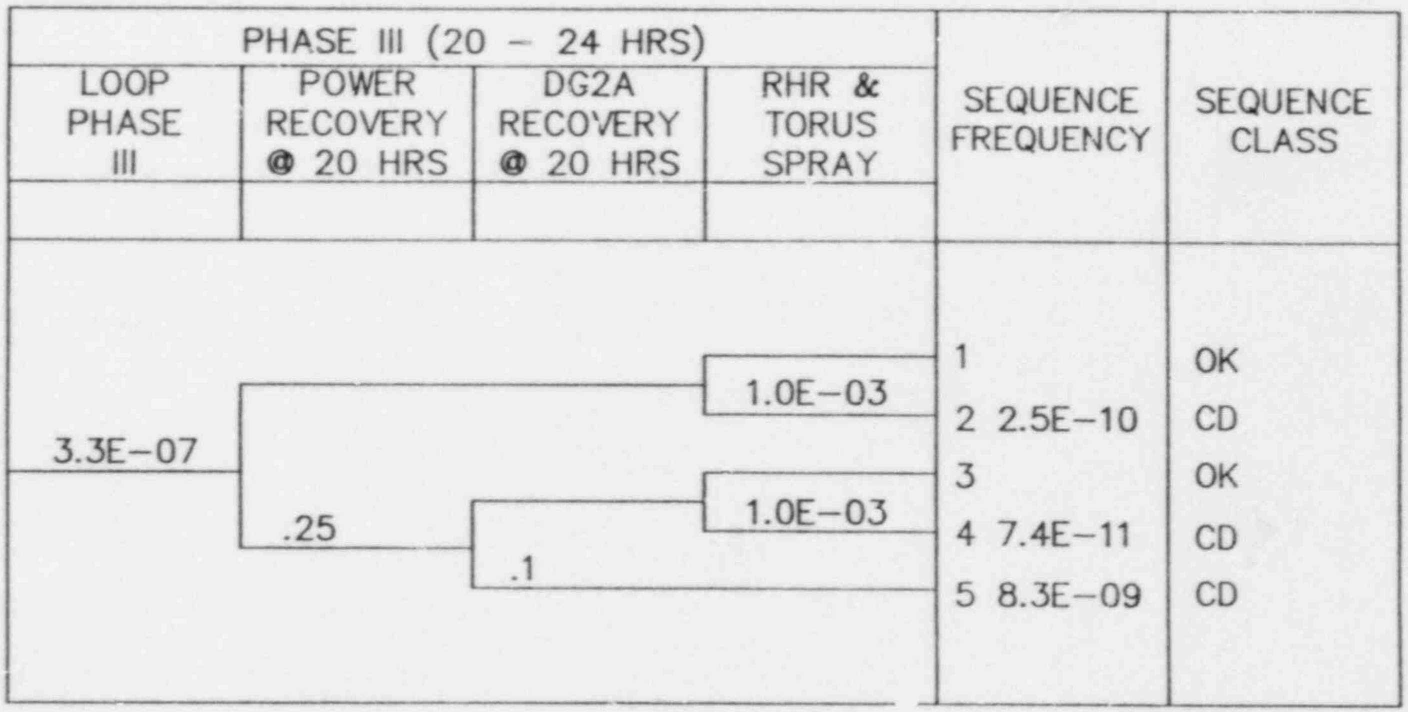


Figure 4-2 (cont'd)

LaSalle Loss of Offsite Power Event Tree
(7-Day Allowed Outage Time)

47002573

a low-low reactor water level signal. Both of these systems are independently powered. The Division III ESF ac bus, which has a dedicated diesel generator as an emergency power source, supplies power for all HPCS system loads. RCIC is a diverse system that relies on steam from the reactor to drive the pump, with the station dc system providing power for control valves and instrumentation. While there is no practical limitation to the operation of HPCS during a SBO, RCIC will operate for only 6.5 hours (6). Though the dc batteries will continue to supply power to permit operation of the system, pressurization of the containment will cause a high exhaust pressure trip of the RCIC turbine. Estimates of the failure probability of these systems were calculated through the use of system fault tree models (Appendix A).

In the event that HPCS and RCIC fail to initiate, the operators can align the fire protection system to supply coolant makeup. Alignment of this alternate source of injection has been proceduralized, but can only be used if the operators depressurize the reactor. The shutoff head of the diesel-driven fire pumps is less than 200 psig, so the system would only be effective as long as dc power was available to allow control of the ADS valves. In order to simplify the structure of the event tree models, it was conservatively assumed that the fire protection system would fail at the same time as RCIC (i.e., 6.5 hours). An explicit model of the fire protection system was not developed for this study, since it was conservatively assumed that system failure was dominated by operator error in aligning the system. Even with procedures to assist in the alignment process, it is anticipated that an SBO in conjunction with the failure of the HPCS and RCIC systems will subject the operators to a high level of stress. Consequently, the operator error rate has been assigned a value of 0.1 (6).

Those sequences in which reactor vessel makeup is successful transfer to the phase II event trees, while the other sequences that are characterized by the unavailability of power and a loss of makeup result in core damage.

Phase II (6.5 to 20 hours). In all sequences that transfer to the phase II event tree, coolant makeup to the reactor has been successful in phase I. For the IIA event tree, HPCS started and was successful in phase I, so core damage through the end of the second phase can be averted through continued HPCS operation or recovery of power. In this event tree, the quantification of the HPCS fault tree did not consider demand faults associated with start of the system; hence, the reliability improves over the phase I HPCS failure value.

For the phase IIB event tree, either RCIC or the fire protection system has served as a reactor coolant makeup source because HPCS initially failed, but each of these systems will fail at 6.5 hours. Therefore, core damage will result unless the operators can successfully restore power or recover the HPCS system. In phase I approximately 45 to 60 percent of HPCS failures can be attributed to the failure of the dedicated emergency diesel generator. (Note that the unavailability of the diesel generators is a function of required testing.) Since the event tree does consider recovery of the 2A diesel generator, it was deemed appropriate to also include a recovery factor for the HPCS diesel (DG 2B).

As in phase I, the recovery of power is assumed to lead to a safe shutdown of the reactor. If power is not recovered and HPCS has failed in this phase, core damage will result. Only those sequences in which HPCS has successfully operated transfer to the final time phase event tree.

Phase III (20 to 24 hours). In the final phase of the LOOP event, coolant makeup has been provided continuously for 20 hours. At this point, the lack of power has prevented removal of decay heat from the containment through the use of the residual heat removal system or the wetwell vent. As heat has been rejected to the containment during the course of the accident, the inability to cool the containment has lead to pressurization. Analyses indicate that the ultimate pressure of 100 psig will be reached at 21 hours (6). If power cannot be recovered, the containment will experience an overpressure failure at 21 hours. With power recovery before 21 hours, however, the operators have adequate time to reduce pressure through the use of the suppression pool sprays and the residual heat removal system.

4.2 EVENT TREE QUANTIFICATION

In examining the quantification of the LOOP event trees—both the three-day and seven-day AOT cases—the dominant contributor to core damage is sequence 5 in phase III. In this sequence, HPCS has successfully operated to ensure sufficient coolant makeup to the reactor vessel, but without the ability to remove heat, the containment fails. With failure of the containment, it is conservatively assumed that core damage eventually occurs.

Smaller contributions to core damage are noted in the second time phase of the accident in which the HPCS system is the only means available to maintain core cooling. On entry to this phase, the probability of core melt is greater if the HPCS system is operating. This is primarily because the entry state with HPCS operating is 20 times more probable than the situation in which HPCS failure has occurred and RCIC or the fire protection system has been used to supply vessel makeup.

Due to the number of coolant makeup options available in the initial phase of the accident, the occurrence of an early core melt due to a LOOP is less likely than a failure later in the accident sequence. This is also true because power is very likely to be restored in the short term—more than 95 percent of losses of offsite power are estimated to be recovered within 6.5 hours. As time extends beyond 10 hours, the probability of recovering power before containment fails is very low (see Appendix B).

5.0 ANALYSIS RESULTS

Quantification of the LOOP event trees provides a means of comparing the baseline risk of core damage with the risk associated with an extension of the 0 diesel generator AOT. As previously mentioned, operation under the current technical specification AOT requirement is modeled by a three-day AOT in which the major contributor to risk would be caused by a LOOP. Although there is a low level of confidence that all maintenance tasks can be completed within the allotted three-day AOT, the baseline excludes the risk due to plant shutdown because the uncertainty in core damage frequency values attributable to the use of a different event tree model make a meaningful comparison between shutdown risk and the risk due to a LOOP difficult. Nevertheless, comparing the baseline risk due to a three-day AOT to the risk of a seven-day outage under the conditions of the proposed technical specification amendment can demonstrate the effectiveness of the risk reduction measures CECo has formulated.

For both quantifications of the LOOP event trees it may be noted that the calculated core damage frequency is extremely low. Several factors may be noted that serve to reduce the risk of continued operation while the shared emergency diesel generator is unavailable:

- The frequency of a LOOP occurring during the period of the AOT is low (8.6E-03 for the seven-day outage).
- The reliability of the division II diesel generator (DG A) to start and run for 24 hours is greater than 95 percent (see Appendix B).
- At LaSalle, multiple sources of coolant makeup to the reactor vessel that do not require Division I or II ac power are available. Even though these systems are not capable of securing a safe shutdown of the reactor, they provide additional time for power recovery.
- LOOP events are not typically caused by catastrophic failures, so the probability of recovery of power in the short term is high.

The important aspects of the results, as presented in Table 5-1, are that the risk associated with the outage of the shared diesel generator is an insignificant contributor to the annual core melt risk. (Since a completed Level I PRA for the LaSalle station is not available, the best-estimate CDF of 5.5E-05 from the Shoreham PRA was used to calculate the values presented in Table 5-1). Also, the core damage frequency estimates for the two cases examined illustrate the effectiveness of the risk reduction measures that would be implemented under the proposed technical specification amendment (i.e., the restrictions or conditions that would apply to the outage of the shared diesel generator).

Because the LOOP initiator frequency increases according to the duration of the outage, a risk increase of approximately 130 percent could be expected as a result of an extension of the AOT from three to seven days if no additional restrictions were imposed. In actuality, the risk increased by substantially less than that amount; therefore, it may be concluded that the conditions that apply to the amended technical specification have the desired effect of reducing the operating risk. In reviewing the fault tree and event tree quantification, it may be seen that the primary risk reduction factor is the requirement to test the operable diesel generators before removing the shared diesel generator from service.

Table 5-1

CORE DAMAGE FREQUENCY RESULTS
THREE-DAY AOT VS. SEVEN-DAY AOT

	Calculated CDF	Increase Over Baseline (%)	Fraction of Annual CDF (%)
3-day AOT under current technical specifications (baseline)	1.1E-08	—	.02
7-day AOT under amended technical specifications	1.9E-08	72.7	.03

The requirement to test the diesel generators 24 hours prior to initiating an outage of the shared diesel was specified based on the results of a recently completed evaluation of testing practices at the LaSalle station (7). This evaluation, which examined various testing patterns for diesel generators to minimize unavailability during an outage of another diesel, demonstrated that testing prior to the outage of a diesel provided the greatest emergency power availability improvement. Also, tests in which the diesel was started and loaded onto its bus were found to be preferable to tests in which the diesel was only started and not loaded. In fact, starting the operable diesel generator every eight hours during the outage of one generator only decreased unavailability by five percent, while starting and loading the diesels only once resulted in a 30 percent reduction in unavailability. The study attributed this difference to the fact that starting a diesel without loading it onto its bus did not verify proper operation of critical functions such as service water cooling and automatic closure of the diesel generator output breaker.

6.0 CONCLUSIONS

CECo proposes to amend the technical specifications to extend the AOT for the common diesel generator (DG 0) from three days to seven days only for those cases in which DG 0 is required to be removed from service to perform preplanned preventive maintenance. One unit will already be shut down.

The analysis required to evaluate the risk significance of the proposed extension was described in Section 3 of this report. The analysis method required that baseline risk measures be determined by assessing the core damage frequency for a three-day outage of the shared diesel generator (DG 0). These baseline results were then compared to the core damage frequency associated with a seven-day outage of DG 0 under the restrictions imposed by the amended technical specifications. Section 5 presented the results of these evaluations.

Although it has been shown that the extension of the AOT from three days to seven days does result in an increase in risk, this increase is only approximately 8E-09. When compared to the annual core damage frequency estimate for a similar plant, such an increase (approximately 0.01 percent) is considered to be insignificant. Additionally, in consideration of the nonquantifiable risks discussed in Section 3.3 (e.g., exclusion of shutdown risk from the baseline), the results bound the true risk impact of the proposed change. Thus, there is a high level of confidence that the impact of the proposed change on the annual core melt frequency is less than 8E-09.

From these results, it may be concluded that implementation of the proposed technical specification change does not pose an undue risk to the general public. As a result, when economic and operational benefits are considered, the proposed technical specification change represents a net benefit to the customers of the Commonwealth Edison Company.

7.0 REFERENCES

1. "Proposed Policy Statement on Technical Specification Improvements for Nuclear Power Reactors," Federal Register, Vol. 52, No. 25, February 6, 1987.

2. Evaluation of Diesel Unavailability and Risk Effective Surveillance Test Intervals, Brookhaven National Laboratory, May 1986, NRC PETS program document.

3. Limerick Probabilistic Risk Assessment, Philadelphia Electric Company, NRC Docket 50-532, 50-533, March 1981.

4. Shoreham Nuclear Power Station Probabilistic Risk Assessment, Long Island Lighting Company, NRC Docket 50-322, June 1983.

5. Brunswick Decay Heat Removal Probabilistic Safety Study, NSAC-83, October 1985.

6. LaSalle County Station Probabilistic Safety Analysis, NEDO-31085, General Electric Company, November 1985.

7. Risk-Based Evaluation of Technical Specification Problems at the LaSalle County Nuclear Station, EPRI NP-5238, June 1987.

Appendix A

FAULT TREE MODELS

FAULT TREE MODELS

Fault tree models for the Unit 2 emergency diesel generators (2A and 2B), the High Pressure Core Spray (HPCS) system, and the Reactor Core Isolation Cooling (RCIC) systems were developed for this study. Because requirements for diesel generator testing differed between the base case and the practices that would be implemented with an amendment of the technical specification, the same versions of the diesel fault tree were quantified with different data decks (see Appendix B). Also, the mission times for the diesel generators and the HPCS and RCIC systems varied in the quantification of the LOOP event tree. These differences also necessitated various quantifications of the models. A description of the various quantification cases is provided in Table A-1.

The fault tree diagrams presented in Figures A-1 through A-4 are reduced from more complex models. All models were initiatially quantified using a cut set truncation of 1.0E-09. Since the top event values were high, the cut set list was truncated at 1.0E-05. All events that did not appear in these cut sets were then removed from the fault tree, but only in the diagram. The actual models used for quantification maintained all basic events.

As with the development of any risk-based models, it was necessary to make specific assumptions concerning the operation of systems. For this study, the following assumptions were made:

- No maintenance unavailabilities were included in either diesel generator model, since the technical specifications forbid the simultaneously maintenance of two diesels for more than two hours.
- Maintenance unavailabilities for the HPCS and RCIC systems were included in the fault tree models with data from the General Electric LaSalle Probabilistic Safety Analysis.
- Failure of the HPCS system due to a loss of room cooling was not modeled in the fault tree. General Electric believes that cooling is not necessary for successful operation of the HPCS pump.

- It was assumed that HPCS pump bearing failures would not be induced by high suppression pool temperature. This assumption is consistent with General Electric's assertion that the HPCS pump could survive temperatures up to suppression pool saturation at the containment failure pressure of 100 psig.

- RCIC was assumed to fail at 6.5 hours due to a high exhaust pressure trip caused by a lack of containment heat removal.

- Due to the removal of the condensate storage tank (CST) suction line in the HPCS system, the only source of suction modeled is the suppression pool.

Table A-1

FAULT TREE QUANTIFICATIONS

Fault Tree	Unavailability	Description
DG2A I	4.4E-02	Mission Time = 24 H DG started and loaded 24 hours prior to DG 0 outage
DG2A II	5.5E-02	Mission Time = 24 H DG started every 8 hours during DG 0 outage
DG2B I	1.8E-02	Mission Time = 6.5H DG started and loaded 24 hours prior to DG 0 outage
DG2B II	2.4E-02	Mission Time = 13.5H DG started and loaded 24 hours prior to DG 0 outage
DG2B III	1.2E-02	Mission Time = 13.5H All demands failures set to 0
DG2B IV	2.8E-02	Mission Time = 6.5 H DG started every 8 hours during DG 0 outage
DG2B V	3.4E-02	Mission Time = 13.5 H DG started every 8 hours during DG 0 outage
HPCS I	4.3E-02	Mission Time = 6.5 H DG2B transfer = 1.8E-02 (DG2B I)
HPCS II	3.9E-02	Mission Time = 13.5 H DG2B transfer = 5.5E-02 (DG2B II)
HPCS III	1.3E-02	Mission Time = 6.5 H DG2B transfer = 1.2E-02 (DG2B III)
HPCS IV	5.0E-02	Mission Time = 6.5 H DG2B transfer = 2.8E-02 (DG2B IV)
HPCS V	5.2E-02	Mission Time = 13.5 H DG2B transfer = 3.4E-02 (DG2B V)
HPCS VI	2.0E-02	Mission Time = 12 H DG2B transfer = 0
RCIC I	7.2E-02	Mission Time = 6.5 H
RCIC II	7.3E-02	Mission Time = 12 H

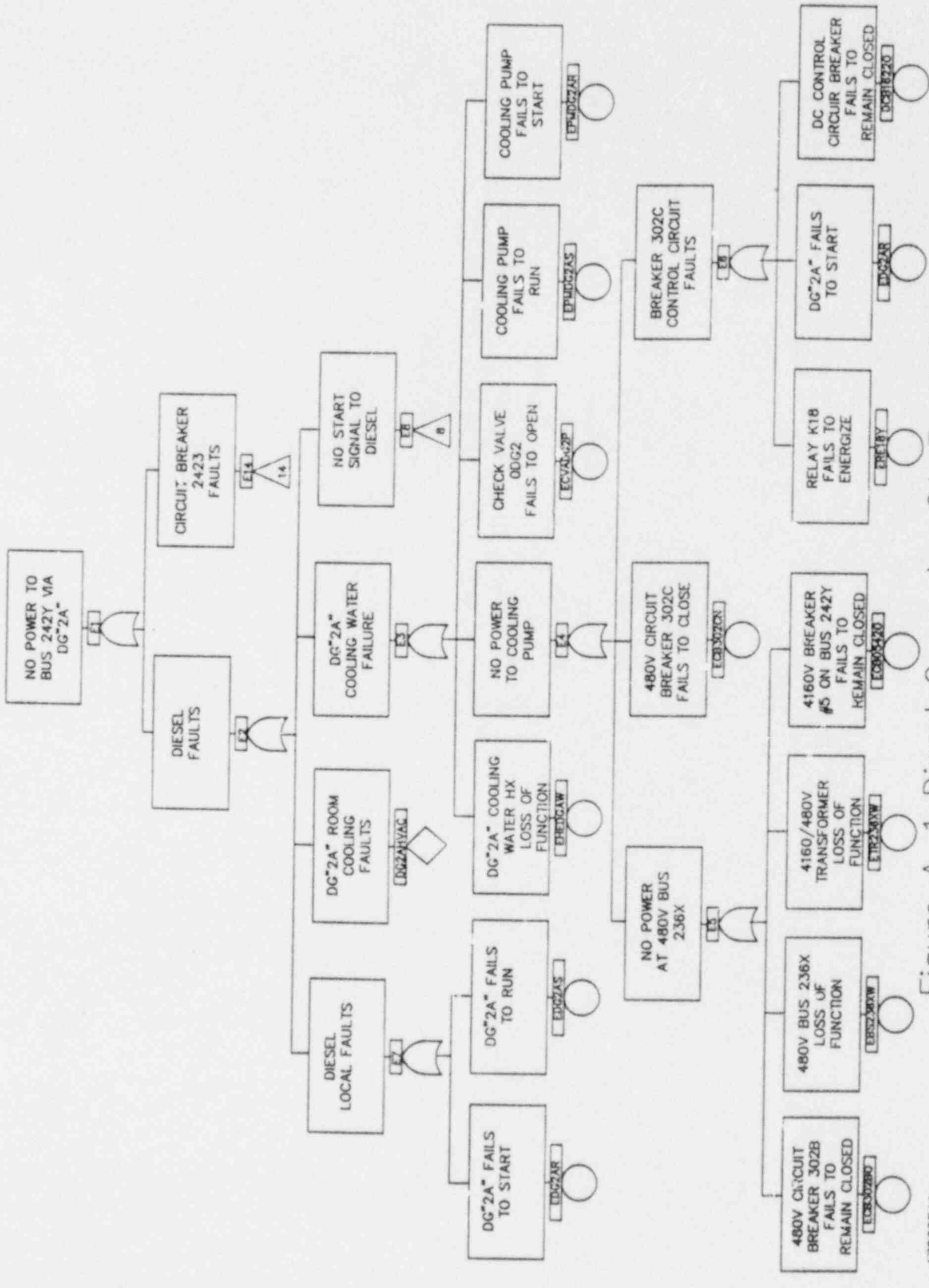
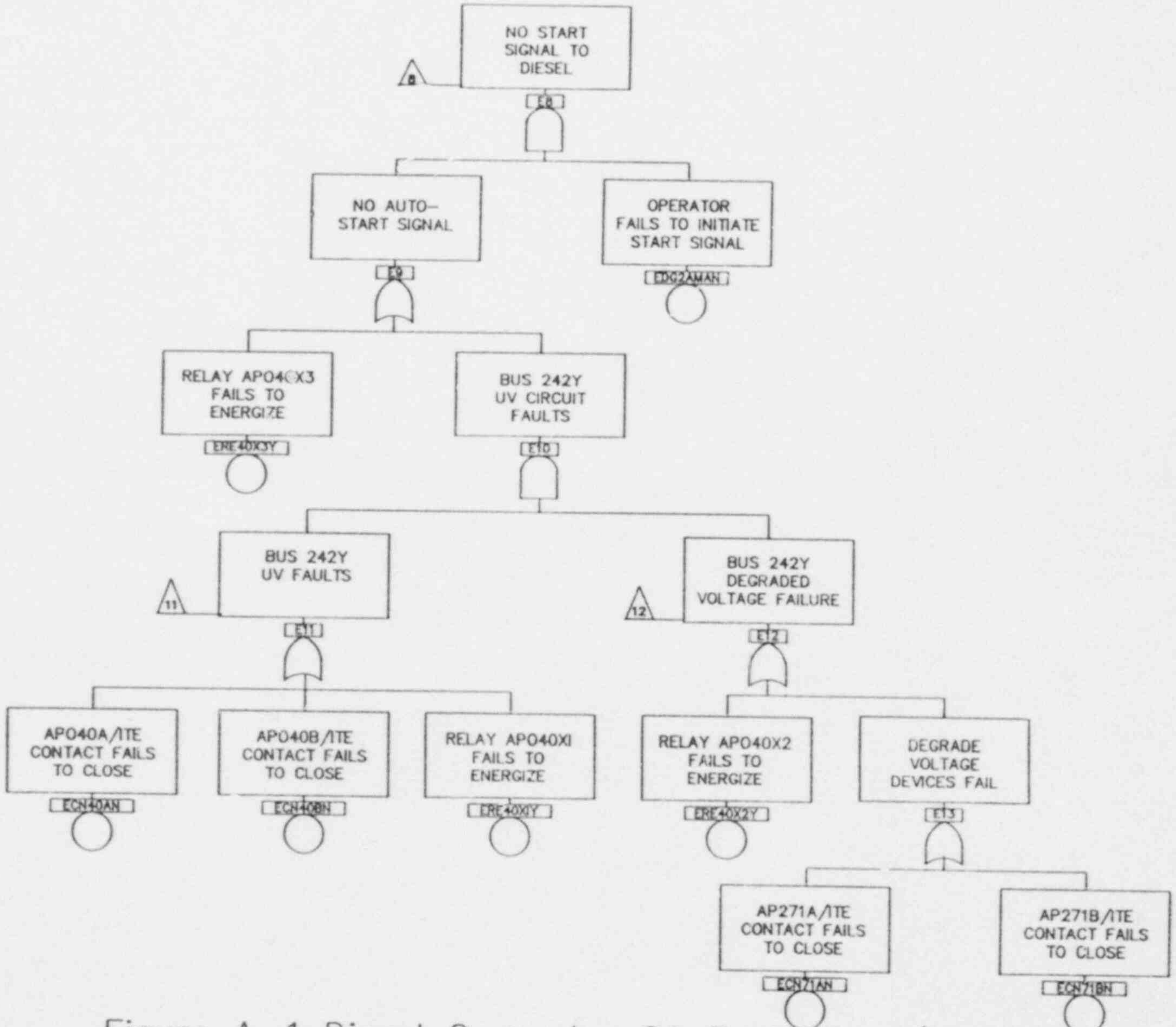


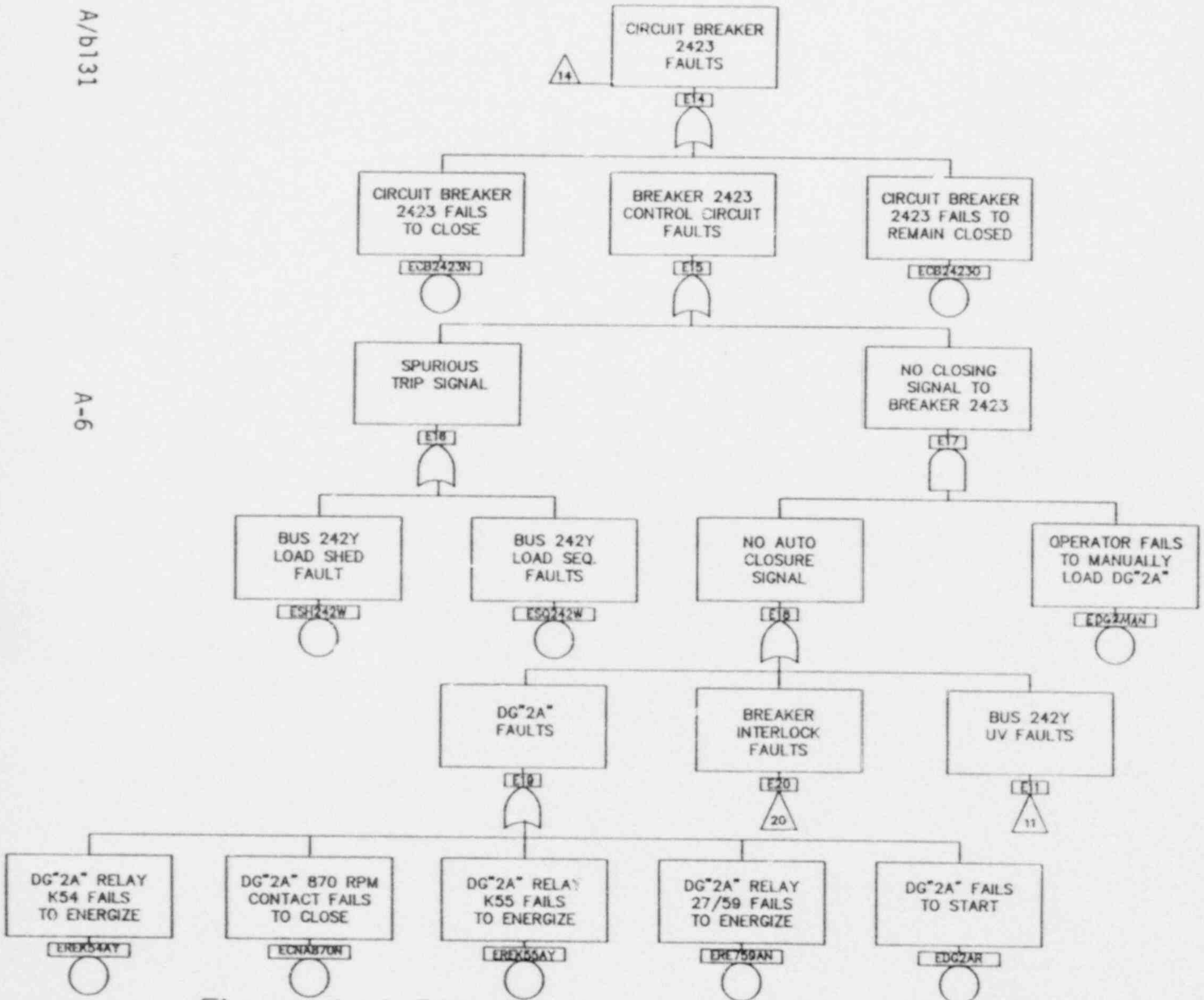
Figure A-1 Diesel Generator 2A Fault Tree

470025A1



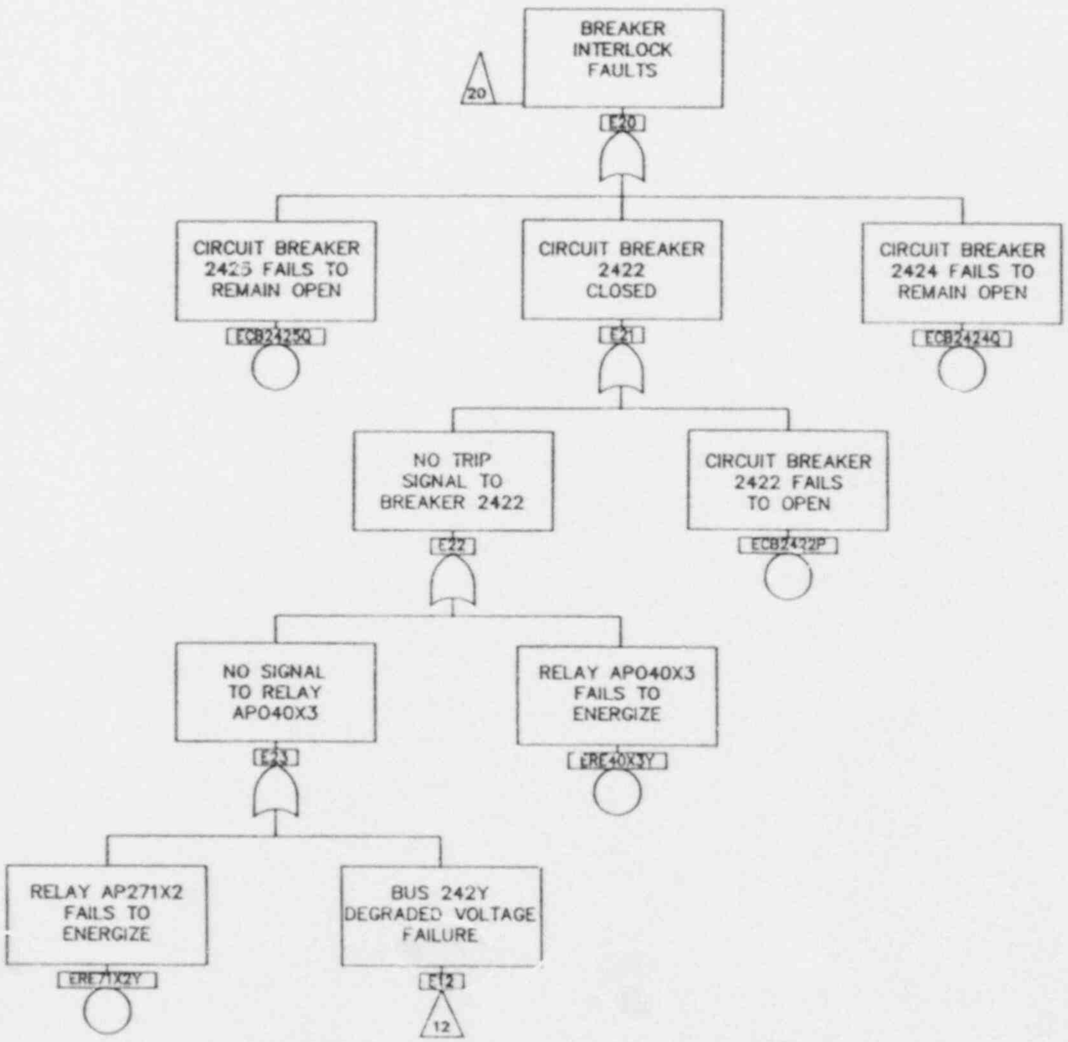
470025A2

Figure A-1 Diesel Generator 2A Fault Tree (continued)



470025A3

Figure A-1 Diesel Generator 2A Fault Tree (continued)



470025A4

Figure A-1 Diesel Generator 2A Fault Tree (continued)

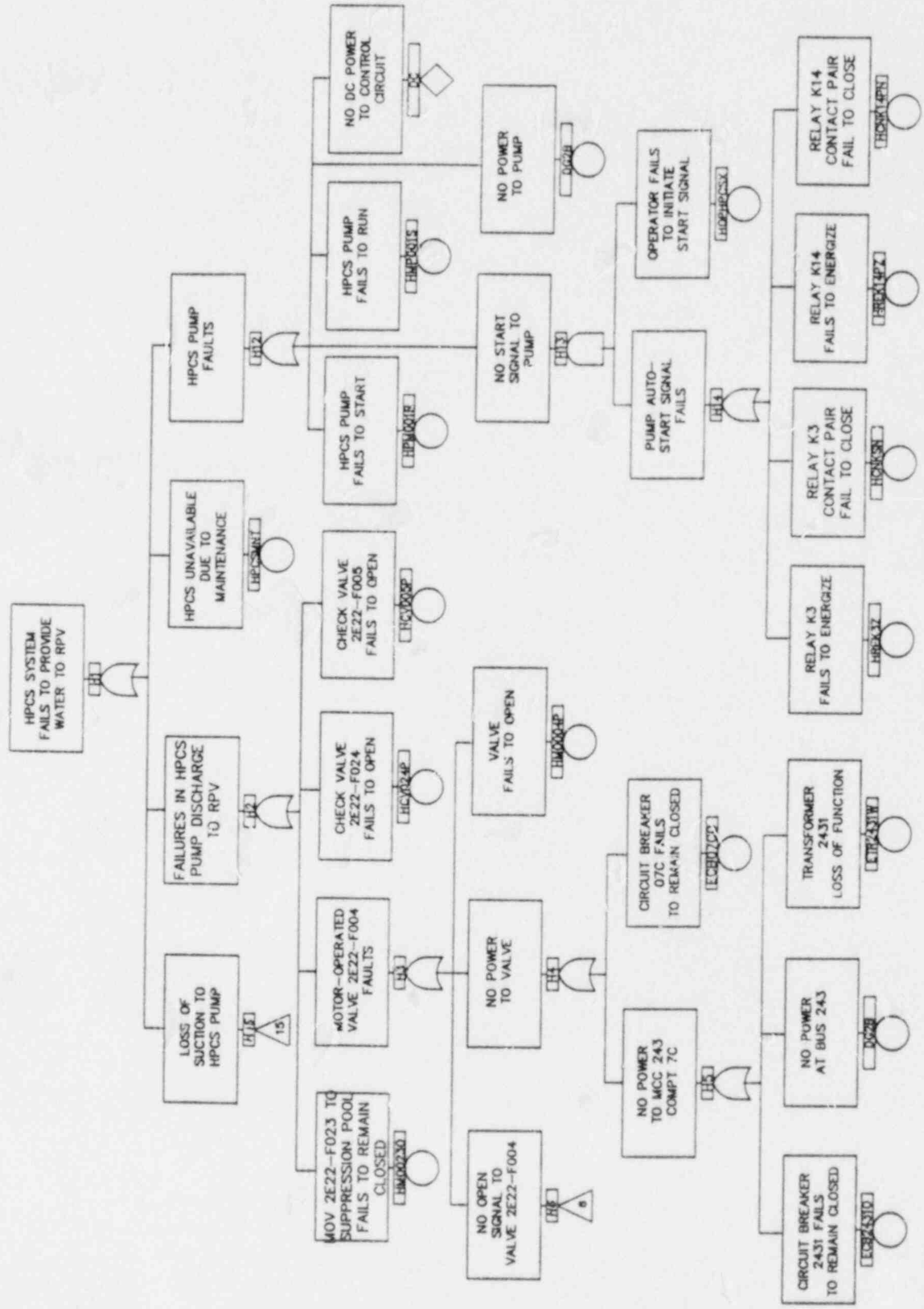


Figure A-2 High Pressure Core Spray Fault Tree

470025H1

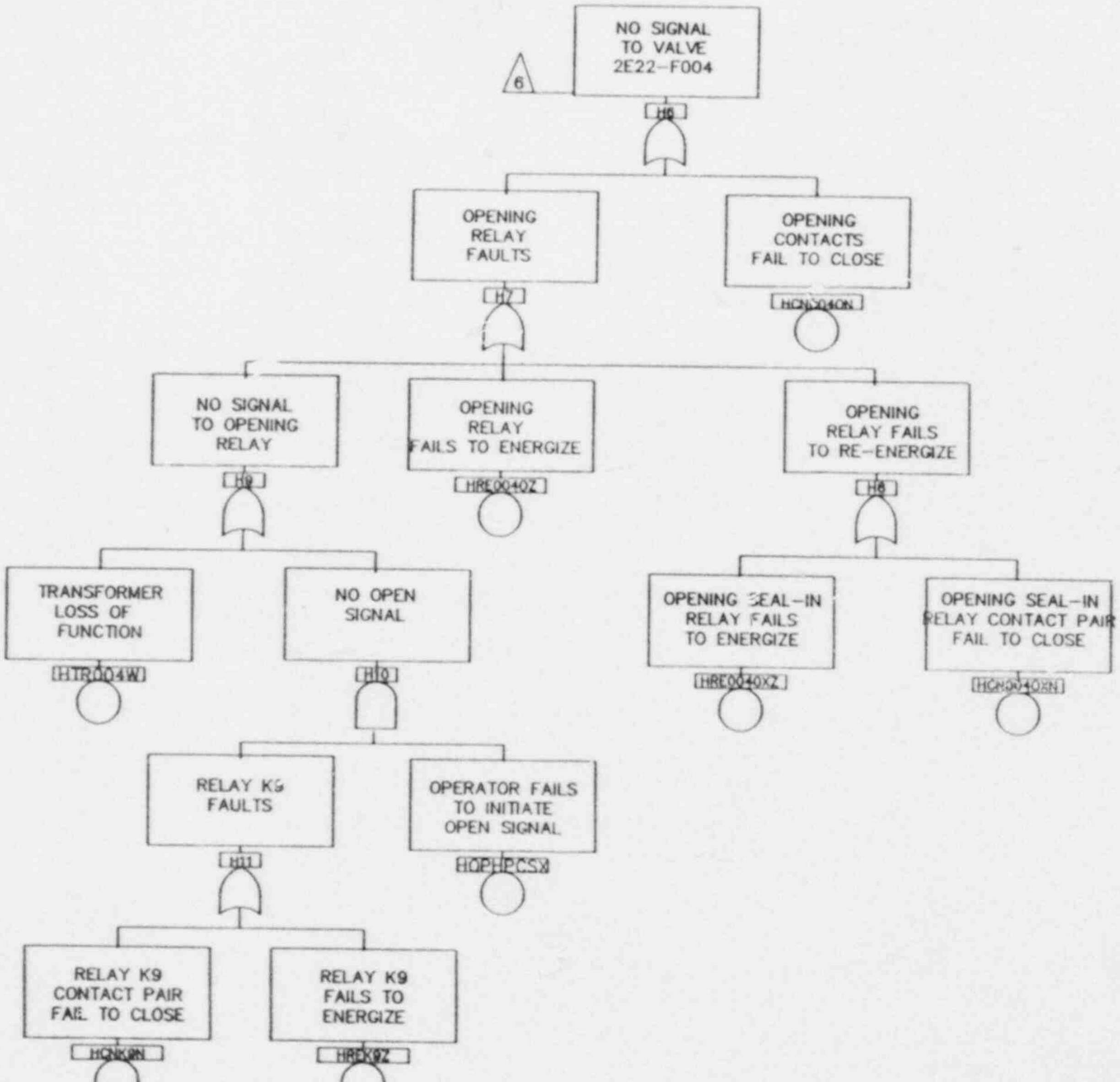
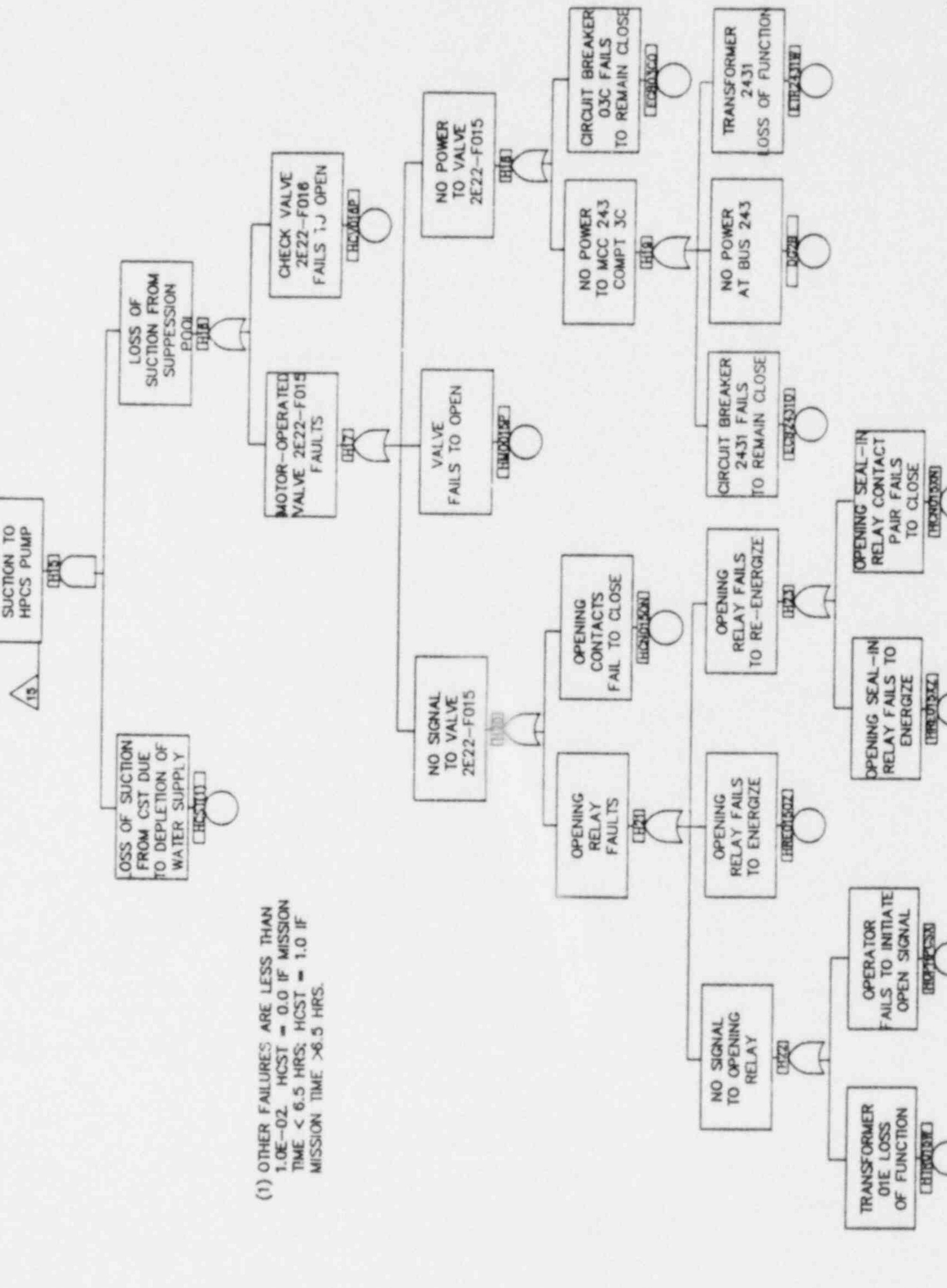


Figure A-2 High Pressure Core Spray System (continued)

470025H2



(1) OTHER FAILURES ARE LESS THAN 1.0E-02. HCST = 0.0 IF MISSION TIME < 6.5 HRS; HCST = 1.0 IF MISSION TIME >6.5 HRS.

470025H3

Figure A-2 High Pressure Core Spray Fault Tree (continued)

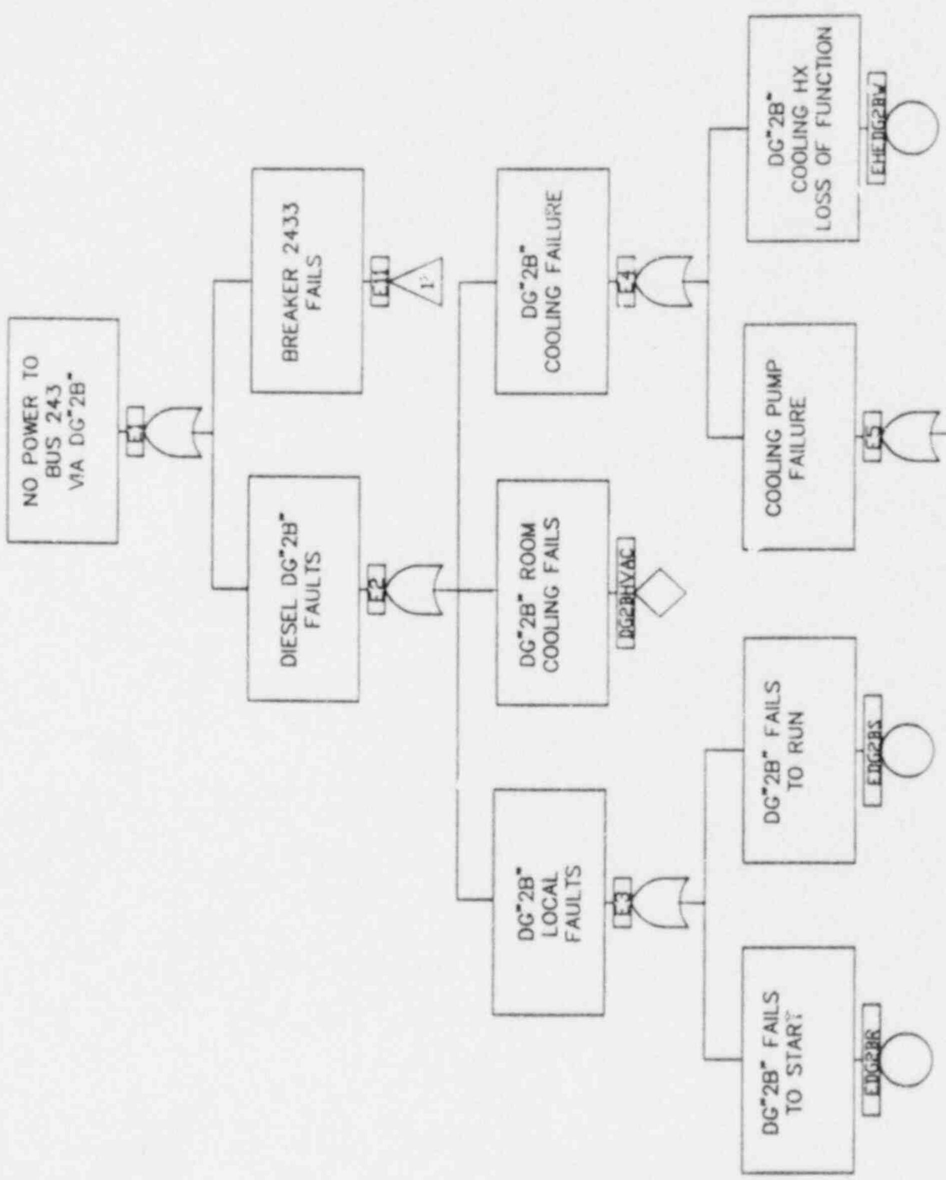


Figure A-3 Diesel Generator 2B Fault Tree

4700258I

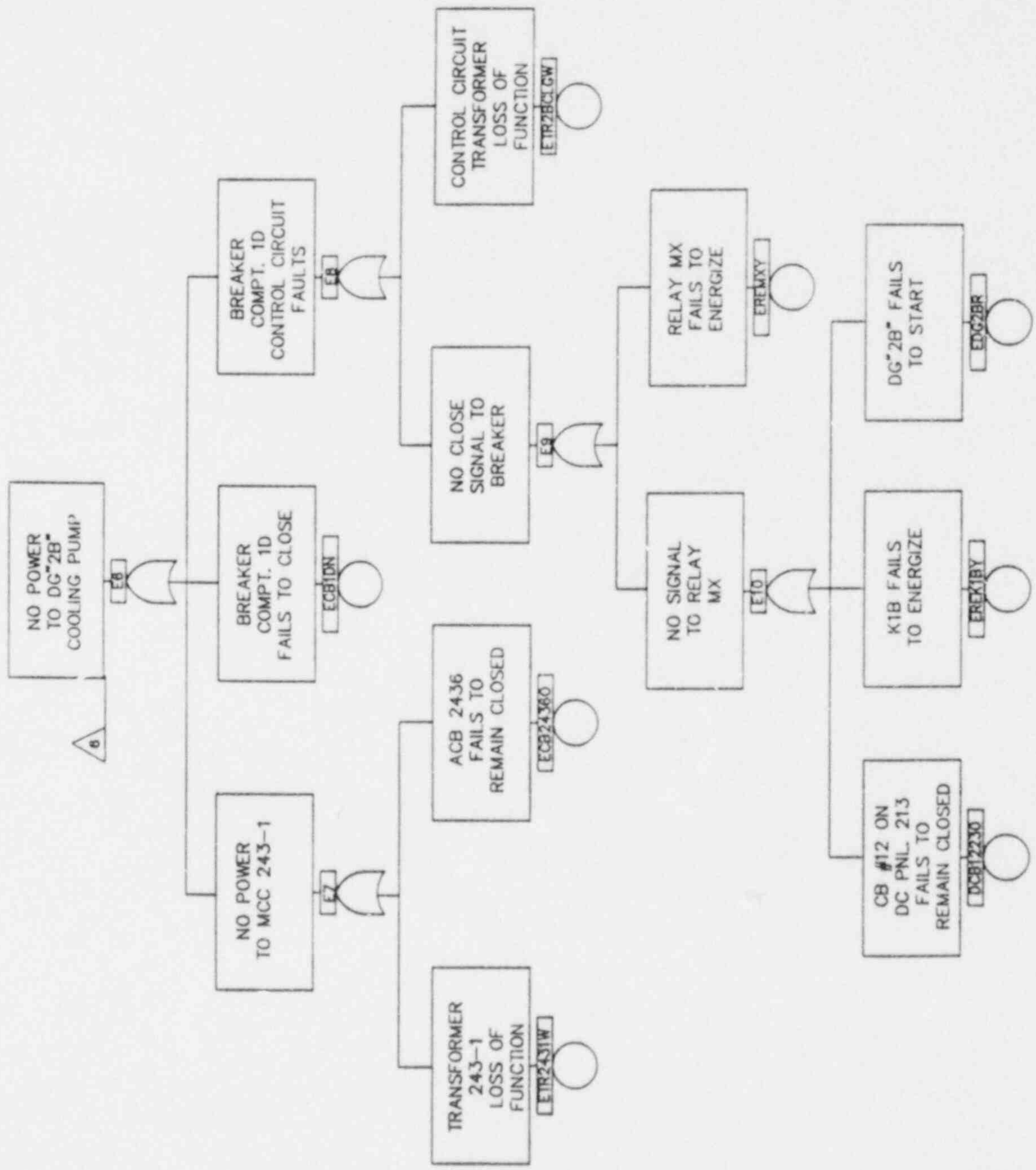


Figure A-3 Diesel Generator 2B Fault Tree (continued)

47002582

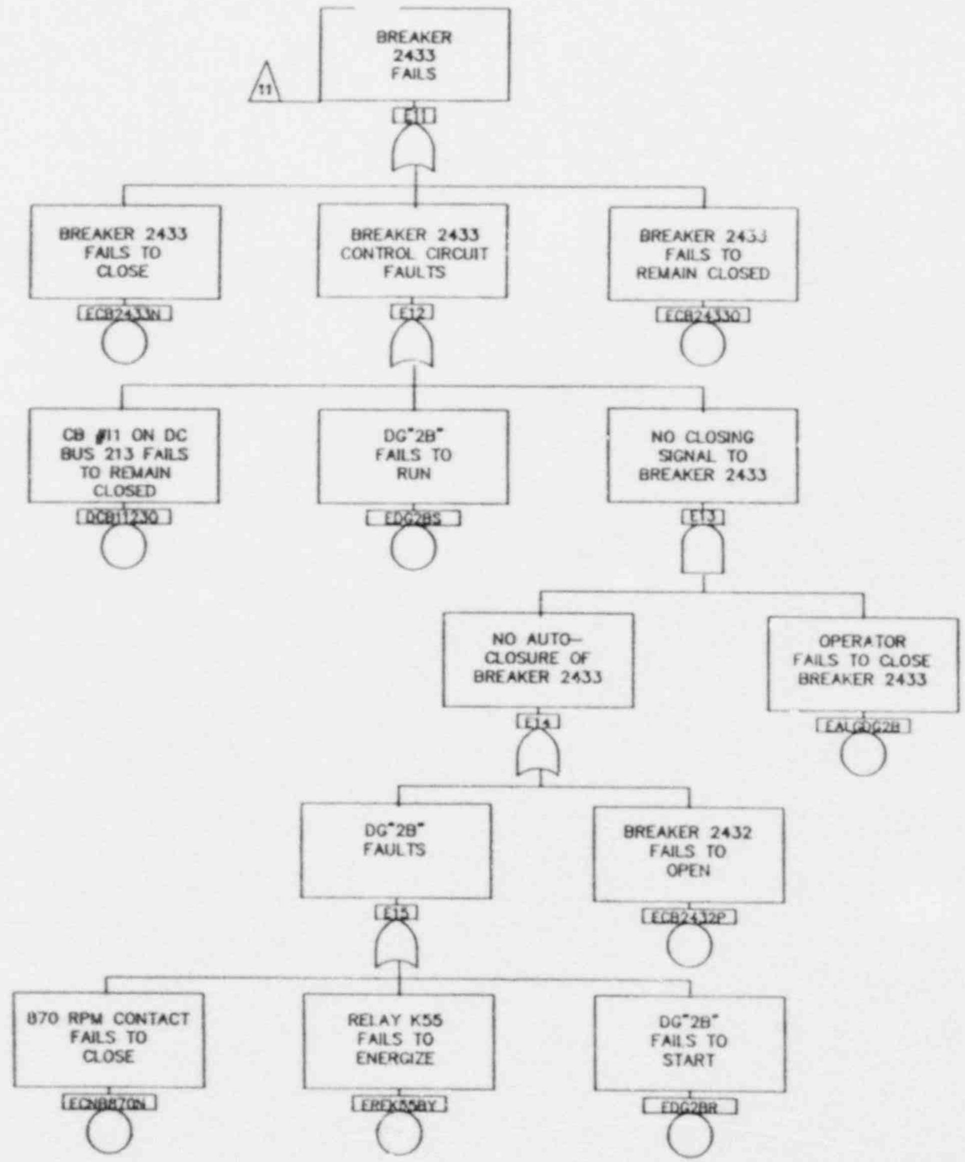
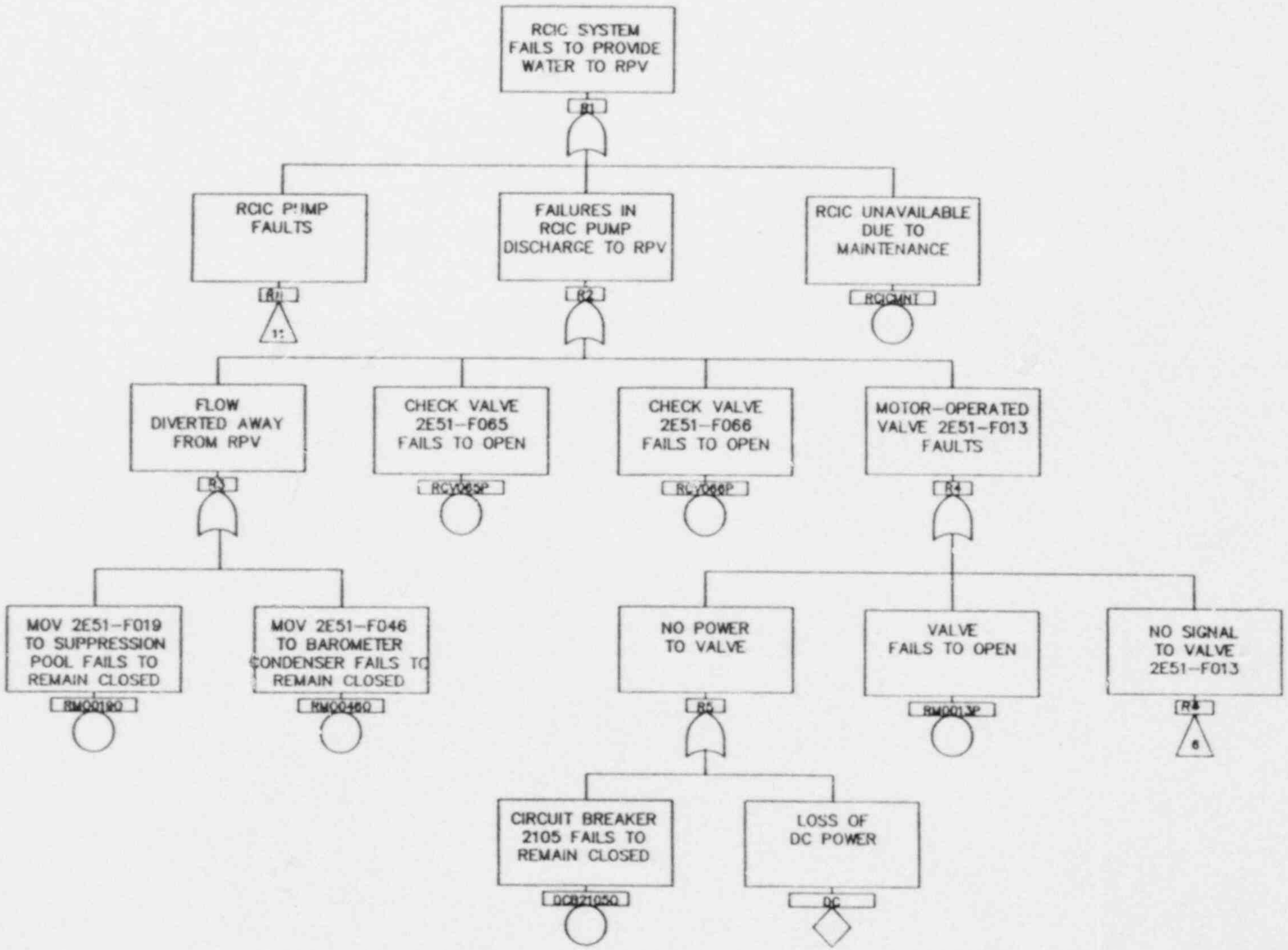


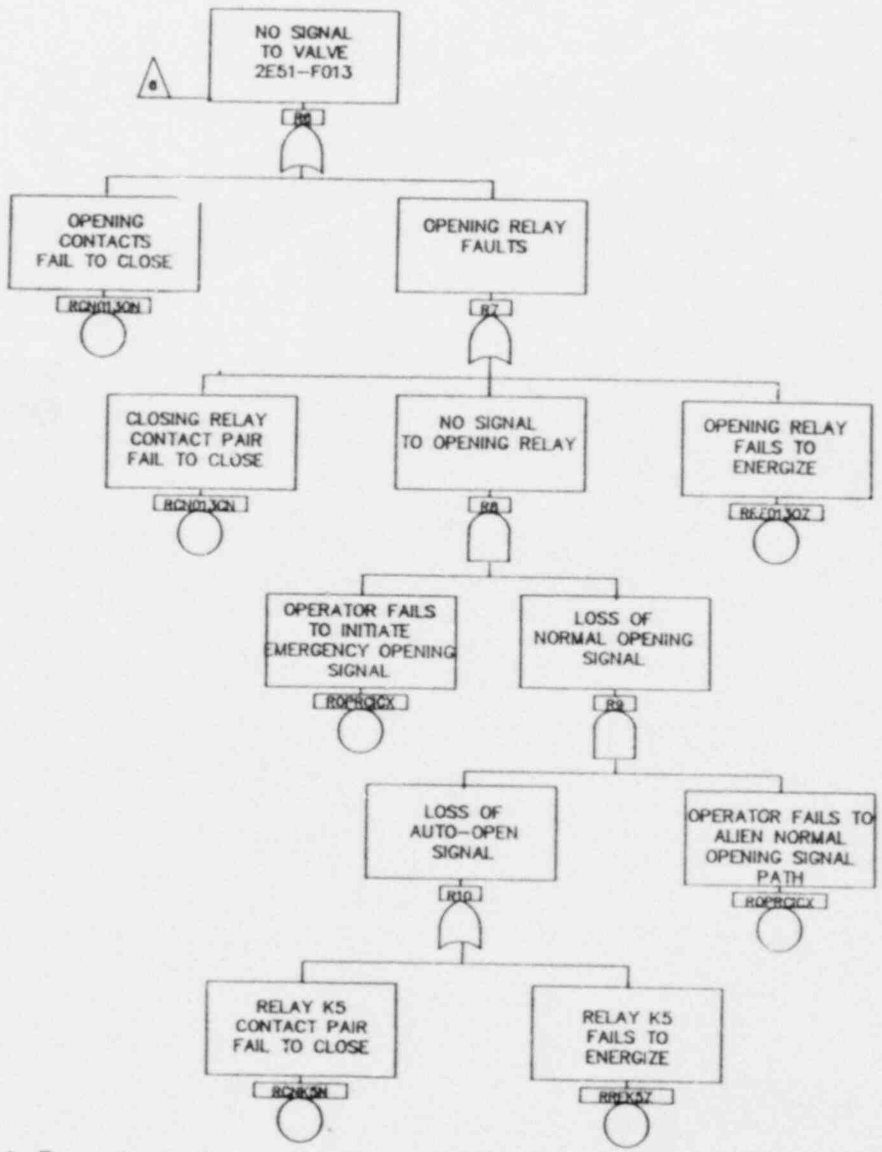
Figure A-3 Diesel Generator 2B Fault Tree (continued)

47002583



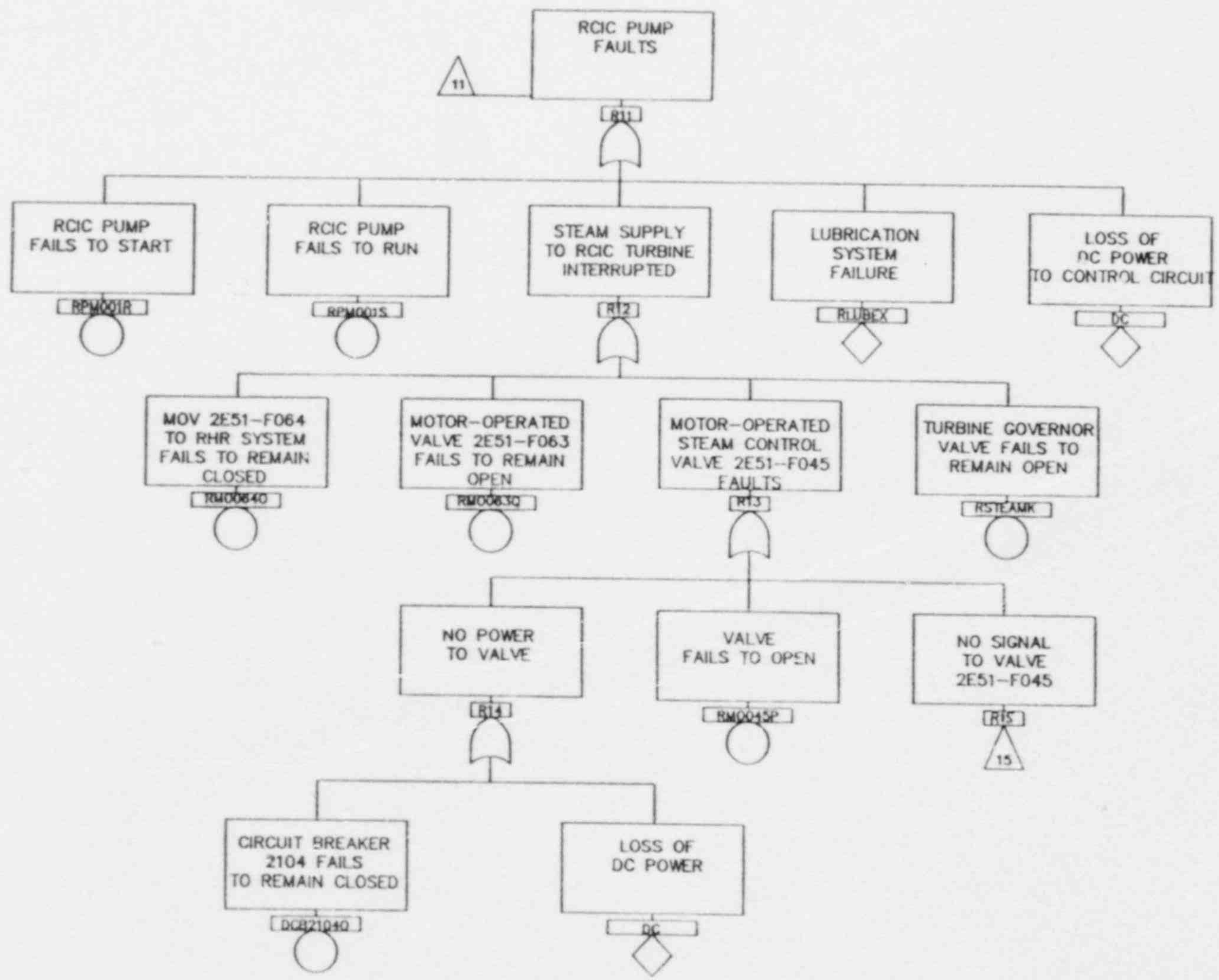
470025R1

Figure A-4 Reactor Core Isolation Cooling Fault Tree



0025R2

Figure A-4 Reactor Core Isolation Cooling Fault Tree (continued)



470025R3

Figure A-4 Reactor Core Isolation Cooling Fault Tree (continued)

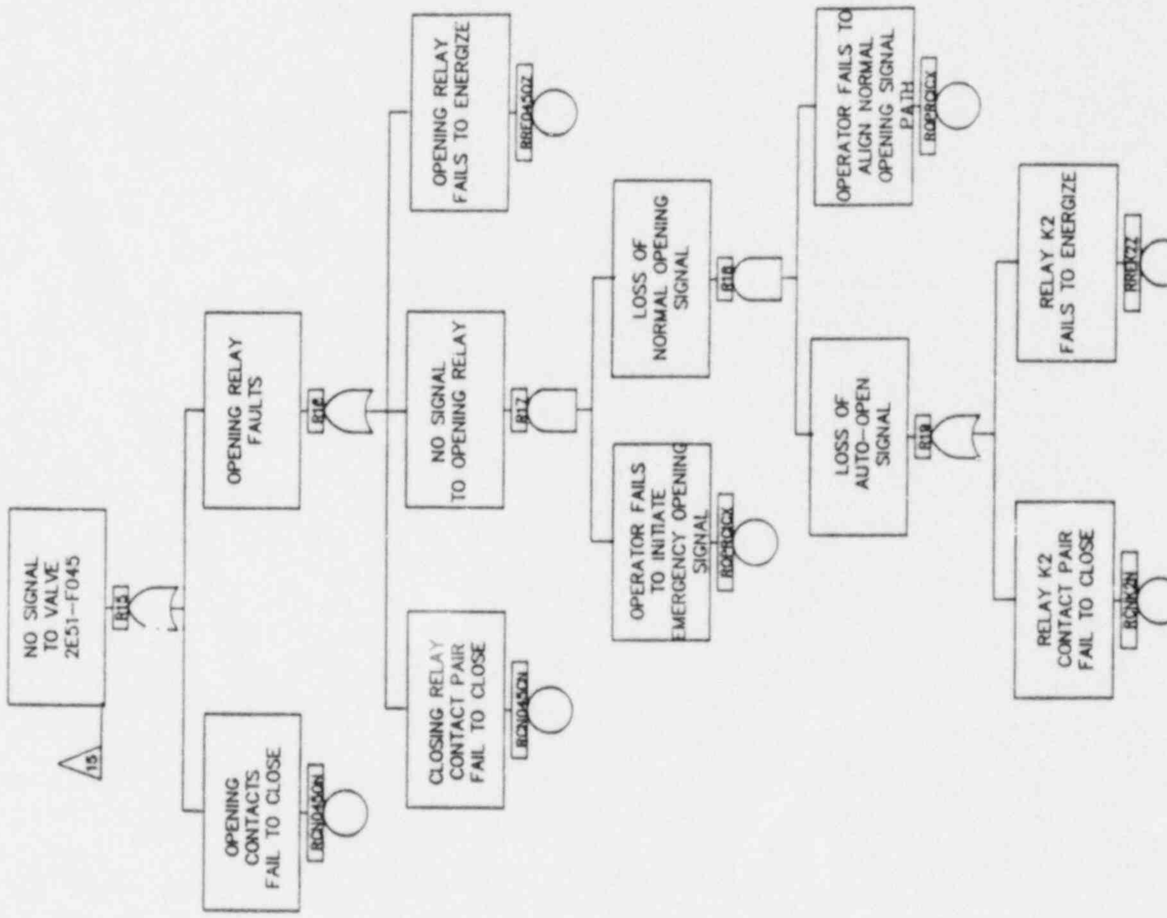


Figure A-4 Reactor Core Isolation Cooling Fault Tree (continued)

Appendix B

DATA

LOSS OF OFFSITE POWER RECOVERY

Time (hours)	Probability of Not Recovering Offsite Power[1]
0	1
45 min.	.44
1	.34
2	.19
3	.13
6.5	.04
20	.01[2]
24	.01

[1] Source: Losses of Offsite Power at U.S. Nuclear Power Plants All Years Through 1985, NSAC/103, May 1986.

[2] Though the NSAC report has determined 99 percent of LOOP events are recovered within 8 hours, it has been conservatively assumed that one percent of events will not be recovered within 24 hours.

EMERGENCY DIESEL GENERATOR RECOVERY

Time (hours)	Probability of Not Recovering Diesel[1]
0	1
.75	.72
6.5	.3
20	.1[2]

[1] Source: LaSalle County Station Probabilistic Safety Analysis, NEDO-31085.

[2] Failure to recover a diesel generator at 20 hours has conservatively assumed to be 0.1.

SYSTEM MAINTENANCE UNAVAILABILITY

System	Maintenance Unavailability[1]
HPCS	5.0E-03
RCIC	1.1E-02

[1] Source: LaSalle County Station Probabilistic Safety Analysis, NEDO-31085.

DG2A FAULT TREE DATA—CASE I

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DCB16220	1.5E-07	108	24	2.0E-05	NPRDS, GE PLANTS
DG2AHVAC	2.5E-06	108	24	3.3E-04	IEEE-500, PG. 1260
EALGDG2A	1.0E-01				OPERATOR ERROR (SCREENING VALUE)
EBS236XW	3.0E-08	108	24	4.0E-06	NUREG/CR-2815, PG. 183
ECB05420	1.7E-05	108	24	2.2E-03	PLANT DATA
ECB2422P	1.0E-03				EGG-EA-5887, PG. 14
ECB2423N	1.7E-05	108		1.8E-03	PLANT DATA
ECB24230	1.7E-05		24	4.1E-04	PLANT DATA
ECB2424Q	1.4E-05		24	3.4E-04	PLANT DATA
ECB2425Q	1.4E-05		24	3.4E-04	PLANT DATA
ECB302BO	3.4E-07	108	24	4.5E-05	IEEE-500, PG. 116
ECB302CN	2.3E-06	108		2.5E-04	IEEE-500, PG. 116
ECN40AN	4.0E-07	6570		2.6E-03	GE
ECN40BN	4.0E-07	6570		2.6E-03	GE
ECN71AN	4.0E-07	6570		2.6E-03	GE
ECN71BN	4.0E-07	6570		2.6E-03	GE
ECNA870N	4.0E-07	6570		2.6E-03	GE
ECVADG2P	6.5E-08	108		3.7E-05	NUREG/CR-1363, PG. 827(GE)
EDG2AR	8.6E-06	108		9.3E-04	PLANT DATA
EDG2AS	8.2E-04		24	2.0E-02	PLANT DATA
EDG2MAN				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
EHEDG2AW	9.0E-07	108	24	1.2E-04	IEEE-500, PG. 1349
EPMDG2AR	8.6E-06	108		9.3E-04	PLANT DATA
EPMDG2AS	1.0E-05		24	2.4E-04	NUREG/CR-2815
ERE18Y	4.0E-07	108		4.3E-05	GE
ERE40X1Y	4.0E-07	6570		2.6E-03	GE
ERE40X2Y	4.0E-07	6570		2.6E-03	GE
ERE40X3Y	4.0E-07	6570		2.6E-03	GE
ERE40X3Y	4.0E-07	6570		2.6E-03	GE
ERE71X2Y	4.0E-07	6570		2.6E-03	GE
ERE759AN	4.0E-07	6570		2.6E-03	GE
EREK54AY	4.0E-07	6570		2.6E-03	GE
EREK55AY	4.0E-07	6570		2.6E-03	GE
ESH242W	4.0E-07	6570		2.6E-03	GE
ESQ242W	1.6E-06	6570		1.1E-02	IEEE-500, PG. 201
ETR236XW	6.0E-07	108	24	7.9E-05	EGG-EA-5887, PG. 183

[1] The detection interval is equal to one-half of the test interval, except for diesel components tested before the DG 0 outage. In this case the test interval would be 8 days, but the average unavailability during the 7-day AOT is calculated by using 4.5 days (test occurs 1 day prior to outage plus 3.5 days for midpoint of outage) as the detection interval.

DG2A FAULT TREE DATA—CASE II

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DCB16220	1.5E-07	365	24	5.8E-05	NPRDS, GE PLANTS
DG2AHVAC	2.5E-06	4	24	7.0E-05	IEEE-500, PG. 1260
EALGDG2A				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
EBS236XW	3.0E-08	365	24	1.2E-05	NUREG/CR-2815, PG. 183
ECB05420	1.7E-05	365	24	6.6E-03	PLANT DATA
ECB2422P				1.0E-03	EGG-EA-5887, PG. 14
ECB2423N	1.7E-05	365		6.2E-03	PLANT DATA
ECB24230	1.7E-05		24	4.1E-04	PLANT DATA
ECB2424Q	1.4E-05		24	3.4E-04	PLANT DATA
ECB2425Q	1.4E-05		24	3.4E-04	PLANT DATA
ECB302BO	3.4E-07	365	24	1.3E-04	IEEE-500, PG. 116
ECB302CN	2.3E-06	365		8.4E-04	IEEE-500, PG. 116
ECN40AN	4.0E-07	6570		2.6E-03	GE
ECN40BN	4.0E-07	6570		2.6E-03	GE
ECN71AN	4.0E-07	6570		2.6E-03	GE
ECN71BN	4.0E-07	6570		2.6E-03	GE
ECNA870N	4.0E-07	6570		2.6E-03	GE
ECVADG2P	6.5E-08	365		2.4E-05	NUREG/CR-1363, PG. 827(GE)
EDG2AR	8.6E-06	4		3.4E-05	PLANT DATA
EDG2AS	8.2E-04		24	2.0E-02	PLANT DATA
EDG2MAN				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
EHEDG2AW	9.0E-07	365	24	3.5E-04	IEEE-500, PG. 1349
EPMDG2AR	8.6E-06	365	24	3.3E-03	PLANT DATA
EPMDG2AS	1.0E-05		24	2.4E-04	NUREG/CR-2815
ERE18Y	4.0E-07	365		1.5E-04	GE
ERE40X1Y	4.0E-07	6570		2.6E-03	GE
ERE40X2Y	4.0E-07	6570		2.6E-03	GE
ERE40X3Y	4.0E-07	6570		2.6E-03	GE
ERE40X3Y	4.0E-07	6570		2.6E-03	GE
ERE71X2Y	4.0E-07	6570		2.6E-03	GE
ERE759AN	4.0E-07	6570		2.6E-03	GE
EREK54AY	4.0E-07	6570		2.6E-03	GE
EREK55AY	4.0E-07	6570		2.6E-03	GE
ESH242W	4.0E-07	6570		2.6E-03	GE
ESQ242W	1.6E-06	6570		1.1E-02	IEEE-500, PG. 201
ETR236XW	6.0E-07	365	24	2.3E-04	EGG-EA-5887, PG. 183

[1] The dectection interval is equal to one-half of the test interval.

DG2B FAULT TREE DATA—CASE I

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DCB11230	1.5E-07	108	6.5	1.7E-05	NPRDS, GE PLANTS
DCB12230	1.5E-07	108	6.5	1.7E-05	NPRDS, GE PLANTS
DG2BHVAC	2.5E-06	108	6.5	2.9E-04	IEEE-500, PG. 1260
EALGDG2B				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
ECB1DN	2.3E-06	108		2.7E-04	IEEE-500, PG. 116
ECB2432P				1.0E-03	EGG-EA-5887, PG. 14
ECB2433N	1.7E-05	108		1.8E-03	PLANT DATA
ECB24330	1.7E-05		6.5	1.1E-04	PLANT DATA
ECB24360	1.7E-05	108	6.5	1.9E-03	PLANT DATA
ECNB870N	4.0E-07	6570		2.6E-03	GE
EDG2BR	8.6E-06	108		9.3E-04	PLANT DATA
EDG2BS	8.2E-04		6.5	5.3E-03	PLANT DATA
EHEDG2BW	9.0E-07	108	6.5	1.0E-04	IEEE-500, PG. 1349
EPMDG2BR	8.6E-06	108		9.3E-04	PLANT DATA
EPMDG2BS	1.0E-05		6.5	6.5E-05	NUREG/CR-2815
EREMXY	4.0E-07	6570		2.6E-03	GE
EREK1BY	4.0E-07	6570		2.6E-03	GE
EREK55BY	4.0E-07	6570		2.6E-03	GE
ETRBCLGW	6.0E-07	108	6.5	6.9E-05	EGG-EA-5887, PG. 183
ETR2431W	6.0E-C7	108	6.5	6.9E-05	EGG-EA-5887, PG. 183

[1] The detection interval is equal to one-half of the test interval except for diesel components tested before the DG 0 outage. In this case the test interval would be 8 days, but the average unavailability of the 7-day AOT is calculated by using 4.5 days as the detection interval.

DG2B FAULT TREE DATA--CASE II

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DCB11230	1.5E-07	108	13.5	1.8E-05	NPRDS, GE PLANTS
DCB12230	1.5E-07	108	13.5	1.8E-05	NPRDS, GE PLANTS
DG2BHVAC	2.5E-06	108	13.5	3.0E-04	IEEE-500, PG. 1260
EALGDG2B				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
ECB1DN	2.3E-06	108		2.7E-04	IEEE-500, PG. 116
ECB2432P				1.0E-03	EGG-EA-5887, PG. 14
ECB2433N	1.7E-05	108		1.8E-03	PLANT DATA
ECB24330	1.7E-05		13.5	2.3E-04	PLANT DATA
ECB24360	1.7E-05	108	13.5	2.1E-03	PLANT DATA
ECNB870N	4.0E-07	6570		2.6E-03	GE
EDG2BR	8.6E-06	108		9.3E-04	PLANT DATA
EDG2BS	8.2E-04		13.5	1.1E-02	PLANT DATA
EHEDG2BW	9.0E-07	108	13.5	1.1E-04	IEEE-500, PG. 1349
EPMDG2BR	8.6E-06	108		9.3E-04	PLANT DATA
EPMDG2BS	1.0E-05		13.5	1.4E-04	NUREG/CR-2815
EREMXY	4.0E-07	6570		2.6E-03	GE
EREK1BY	4.0E-07	6570		2.6E-03	GE
EREK55BY	4.0E-07	6570		2.6E-03	GE
ETRBCLGW	6.0E-07	108	13.5	7.3E-05	EGG-EA-5887, PG. 183
ETR2431W	6.0E-07	108	13.5	7.3E-05	EGG-EA-5887, PG. 183

[1] The detection interval is equal to one-half of the test interval except for diesel components tested before the DG 0 outage. In this case the test interval would be 8 days, but the average unavailability of the 7-day AOT is calculated by using 4.5 days as the detection interval.

DG2B FAULT TREE DATA—CASE III

Identifier	Lambda	Detection Interval	Mission Time	Failure Data	Data Source
DCB11230	1.5E-07		13.5	2.0E-06	NPRDS, GE PLANTS
DCB12230	1.5E-07		13.5	2.0E-06	NPRDS, GE PLANTS
DG2BHVAC	2.5E-06		13.5	3.4E-05	IEEE-500, PG. 1260
EALGDG2B				0.0	
ECB1DN				0.0	
ECB2432P				0.0	
ECB2433N				0.0	
ECB24330	1.7E-05		13.5	2.3E-04	PLANT DATA
ECB24360	1.7E-05		13.5	2 [illegible] 04	PLANT DATA
ECNB870N				[illegible]	
EDG2BR				[illegible]0	
EDG2BS	8.2E-04		13.5	1.1E-02	PLANT DATA
EHEDG2BW	9.0E-07		13.5	1.2E-05	IEEE-500, PG. 1349
EPMDG2BR				0.0	
EPMDG2BS	1.0E-05		13.5	1.4E-04	NUREG/CR-2815
EREMXY				0.0	
EREK1BY				0.0	
EREK55BY				0.0	
ETRBCLGW	6.0E-07		13.5	8.1E-06	EGG-EA-5887, PG. 183
ETR2431W	6.0E-07		13.5	8.1E-06	EGG-EA-5887, PG. 183

DG2B FAULT TREE DATA—CASE IV

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DCB11230	1.5E-07	365	6.5	5.6E-05	NPRDS, GE PLANTS
DCB12230	1.5E-07	365	6.5	5.6E-05	NPRDS, GE PLANTS
DG2BHVAC	2.5E-06	4	6.5	2.6E-05	IEEE-500, PG. 1260
EALGDG2B				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
ECB1DN	2.3E-06	365		8.4E-04	IEEE-500, PG. 116
ECB2432P				1.0E-03	EGG-EA-5887, PG. 14
ECB2433N	1.7E-05	365		6.2E-03	PLANT DATA
ECB24330	1.7E-05		6.5	1.1E-04	PLANT DATA
ECB24360	1.7E-05	365	6.5	6.3E-03	PLANT DATA
ECNB870N	4.0E-07	6570		2.6E-03	GE
EDG2BR	8.6E-06	4		3.4E-05	PLANT DATA
EDG2BS	8.2E-04		6.5	5.3E-03	PLANT DATA
EHEDG2BW	9.0E-07	365	6.5	3.3E-04	IEEE-500, PG. 1349
EPMDG2BR	8.6E-06	365		3.1E-03	PLANT DATA
EPMDG2BS	1.0E-05		6.5	6.5E-05	NUREG/CR-2815
EREMXY	4.0E-07	6570		2.6E-03	GE
EREK1BY	4.0E-07	6570		2.6E-03	GE
EREK55BY	4.0E-07	6570		2.6E-03	GE
ETRBCLGW	6.0E-07	365	6.5	2.2E-04	EGG-EA-5887, PG. 183
ETR2431W	6.0E-07	365	6.5	2.2E-04	EGG-EA-5887, PG. 183

[1] The detection interval is equal to one-half of the test interval.

DG2B FAULT TREE DATA—CASE V

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DCB11230	1.5E-07	365	13.5	5.7E-05	NPRDS, GE PLANTS
DCB12230	1.5E-07	365	13.5	5.7E-05	NPRDS, GE PLANTS
DG2BHVAC	2.5E-06	4	13.5	4.4E-05	IEEE-500, PG. 1260
EALGDG2B				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
ECB1DN	2.3E-06	365		8.4E-04	IEEE-500, PG. 116
ECB2432P				1.0E-03	EGG-EA-5887, PG. 14
ECB2433N	1.7E-05	365		6.2E-03	PLANT DATA
ECB24330	1.7E-05		13.5	2.3E-04	PLANT DATA
ECB24360	1.7E-05	365	13.5	6.4E-03	PLANT DATA
ECNB870N	4.0E-07	6570		2.6E-03	GE
EDG2BR	8.6E-06	4		3.4E-05	PLANT DATA
EDG2BS	8.2E-04		13.5	1.1E-02	PLANT DATA
EHEDG2BW	9.0E-07	365	13.5	3.4E-04	IEEE-500, PG. 1349
EPMDG2BR	8.6E-06	365		3.1E-03	PLANT DATA
EPMDG2BS	1.0E-05		13.5	1.4E-04	NUREG/CR-2815
EREMXY	4.0E-07	6570		2.6E-03	GE
EREK1BY	4.0E-07	6570		2.6E-03	GE
EREK55BY	4.0E-07	6570		2.6E-03	GE
ETRBCLGW	6.0E-07	365	13.5	2.3E-04	EGG-EA-5887, PG. 183
ETR2431W	6.0E-07	365	13.5	2.3E-04	EGG-EA-5887, PG. 183

[1] The detection interval is equal to one-half of the test interval.

HPCS FAULT TREE DATA—CASE I

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DC	1.2E-06	365	6.5	4.5E-04	IEEE-500, PG. 81
DG2B				1.8E-02	CASE I
ECB03CO	1.7E-05	84	6.5	1.5E-03	PLANT DATA
ECB07CO	1.7E-05	84	6.5	1.5E-03	PLANT DATA
ECB24310	3.4E-05	84	6.5	3.1E-03	PLANT DATA
ETR2431W	6.0E-07	84	6.5	5.4E-05	EGG-EA-5887, PG. 183
HCN004ON				1.0E-04	EGG-EA-5887, PG. 15
HCN004XN				1.0E-04	EGG-EA-5887, PG. 15
HCN015ON				1.0E-04	EGG-EA-5887, PG. 15
HCN015XN				1.0E-04	EGG-EA-5887, PG. 15
HCNK3N				1.0E-04	EGG-EA-5887, PG. 15
HCNK9N				1.0E-04	EGG-EA-5887, PG. 15
HCNK14PN				1.0E-04	EGG-EA-5887, PG. 15
HCV005P				1.4E-04	NUREG-1363
HCV016P				1.4E-04	NUREG-1363
HCV024P				1.4E-04	NUREG-1363
HMO004P				7.8E-03	NUREG-1363
HMO015P				7.8E-03	NUREG-1363
HMO023O	1.6E-07	365	6.5	5.9E-05	GE 22A2689
HOPHPCSX				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
HPCSMNT				5.0E-03	NEDO-31085
HPM001R	6.3E-06	365		2.3E-03	NRC 1205
HPM001S	9.7E-06		6.5	6.3E-05	NRC 1205
HRE004OZ				1.0E-04	EGG-EA-5887, PG. 15
HRE004XZ				1.0E-04	EGG-EA-5887, PG. 15
HRE015OZ				1.0E-04	EGG-EA-5887, PG. 15
HRE015XZ				1.0E-04	EGG-EA-5887, PG. 15
HREK14PZ				1.0E-04	EGG-EA-5887, PG. 15
HREK3Z				1.0E-04	EGG-EA-5887, PG. 15
HREK9Z				1.0E-04	EGG-EA-5887, PG. 15
HTR004W	6.0E-07	84	6.5	5.4E-05	EGG-EA-5887, PG. 183
HTR015W	6.0E-07	84	6.5	5.4E-05	EGG-EA-5887

[1] Detection intervals for components noted in this list are for one-half of the AOT (84 hours) or one-half of the test interval.

HPCS FAULT TREE DATA—CASE II

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DC	1.2E-06	365	13.5	4.5E-04	IEEE-500, PG. 81
DG2B				2.4E-02	CASE II
ECB03CO	1.7E-05	84	13.5	1.7E-03	PLANT DATA
ECB07CO	1.7E-05	84	13.5	1.7E-03	PLANT DATA
ECB24310	3.4E-05	84	13.5	3.3E-03	PLANT DATA
ETR2431W	6.0E-07	84	13.5	5.9E-05	EGG-EA-5887, PG. 183
HCN0040N				1.0E-04	EGG-EA-5887, PG. 15
HCN004XN				1.0E-04	EGG-EA-5887, PG. 15
HCN0150N				1.0E-04	EGG-EA-5887, PG. 15
HCN015XN				1.0E-04	EGG-EA-5887, PG. 15
HCNK3N				1.0E-04	EGG-EA-5887, PG. 15
HCNK9N				1.0E-04	EGG-EA-5887, PG. 15
HCNK14PN				1.0E-04	EGG-EA-5887, PG. 15
HCV005P				1.4E-04	NUREG-1363
HCV016P				1.4E-04	NUREG-1363
HCV024P				1.4E-04	NUREG-1363
HMO004P				7.8E-03	NUREG-1363
HMO015P				7.8E-03	NUREG-1363
HMO0230	1.6E-07	365	13.5	6.1E-05	GE 22A2689
HOPHPCSX				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
HPCSMNT				5.0E-03	NEDO-31085
HPM001R	6.3E-06	365		2.3E-03	NRC 1205
HPM001S	9.7E-06		13.5	1.3E-04	NRC 1205
HRE0040Z				1.0E-04	EGG-EA-5887, PG. 15
HRE004XZ				1.0E-04	EGG-EA-5887, PG. 15
HRE0150Z				1.0E-04	EGG-EA-5887, PG. 15
HRE015XZ				1.0E-04	EGG-EA-5887, PG. 15
HREK14PZ				1.0E-04	EGG-EA-5887, PG. 15
HREK3Z				1.0E-04	EGG-EA-5887, PG. 15
HREK9Z				1.0E-04	EGG-EA-5887, PG. 15
HTR004W	6.0E-07	84	13.5	5.9E-05	EGG-EA-5887, PG. 183
HTR015W	6.0E-07	84	13.5	5.9E-05	EGG-EA-5887

[1] Detection intervals for components noted in this list are for one-half of the AOT (84 hours) or one-half of the test interval.

HPCS FAULT TREE DATA—CASE III

Identifier	Lambda	Detection Interval	Mission Time	Failure Data	Data Source
DC	1.2E-06		13.5	1.6E-05	IEEE-500, PG. 81
DG2B				1.2E-02	CASE III
ECB03CO	1.7E-05		13.5	2.3E-04	PLANT DATA
ECB07CO	1.7E-05		13.5	2.3E-04	PLANT DATA
ECB24310	3.4E-05		13.5	4.6E-04	PLANT DATA
ETR2431W	6.0E-07		13.5	8.1E-06	EGG-EA-5887, PG. 183
HCN0040N				0.0	
HCN004XN				0.0	
HCN0150N				0.0	
HCN015XN				0.0	
HCNK3N				0.0	
HCNK9N				0.0	
HCNK14PN				0.0	
HCV005P				0.0	
HCV016P				0.0	
HCV024P				0.0	
HMO004P				0.0	
HMO015P				0.0	
HMO0230	1.6E-07		13.5	2.2E-06	GE 22A2689
HOPHPCSX				0.0	
HPCSMNT				0.0	
HPM001R				0.0	
HPM001S	9.7E-06		13.5	1.3E-04	NRC 1205
HRE0040Z				0.0	
HRE004XZ				0.0	
HRE0150Z				0.0	
HRE015XZ				0.0	
HREK14PZ				0.0	
HREK3Z				0.0	
HREK9Z				0.0	
HTR004W	6.0E-07		13.5	8.1E-06	EGG-EA-5887, PG. 183
HTR015W	6.0E-07		13.5	8.1E-06	EGG-EA-5887

HPCS FAULT TREE DATA—CASE IV

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DC	1.2E-06	365	6.5	4.5E-04	IEEE-500, PG. 81
DG2B				2.8E-02	CASE IV
ECB03CO	1.7E-05	36	6.5	7.2E-04	PLANT DATA
ECB07CO	1.7E-05	36	6.5	7.2E-04	PLANT DATA
ECB2431O	3.4E-05	36	6.5	1.4E-03	PLANT DATA
ETR2431W	6.0E-07	36	6.5	2.6E-05	EGG-EA-5887, PG. 183
HCN004ON				1.0E-04	EGG-EA-5887, PG. 15
HCN004XN				1.0E-04	EGG-EA-5887, PG. 15
HCN015ON				1.0E-04	EGG-EA-5887, PG. 15
HCN015XN				1.0E-04	EGG-EA-5887, PG. 15
HCNK3N				1.0E-04	EGG-EA-5887, PG. 15
HCNK9N				1.0E-04	EGG-EA-5887, PG. 15
HCNK14PN				1.0E-04	EGG-EA-5887, PG. 15
HCV005P				1.4E-04	NUREG-1363
HCV016P				1.4E-04	NUREG-1363
HCV024P				1.4E-04	NUREG-1363
HMO004P				7.8E-03	NUREG-1363
HMO015P				7.8E-03	NUREG-1363
HMO023O	1.6E-07	365	6.5	5.9E-05	GE 22A2689
HOPHPCSX				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
HPCSMNT				5.0E-03	NEDO-31085
HPM001R	6.3E-06	365		2.3E-03	NRC 1205
HPM001S	9.7E-06		6.5	6.3E-05	NRC 1205
HRE004OZ				1.0E-04	EGG-EA-5887, PG. 15
HRE004XZ				1.0E-04	EGG-EA-5887, PG. 15
HRE015OZ				1.0E-04	EGG-EA-5887, PG. 15
HRE015XZ				1.0E-04	EGG-EA-5887, PG. 15
HREK14PZ				1.0E-04	EGG-EA-5887, PG. 15
HREK3Z				1.0E-04	EGG-EA-5887, PG. 15
HREK9Z				1.0E-04	G-EA-5887, PG. 15
HTR004W	6.0E-07	36	6.5	2.6E-05	G-EA-5887, PG. 183
HTR015W	6.0E-07	36	6.5	2.6E-05	G-EA-5887

[1] Detection intervals for components noted in this list are for one-half of the AOT (36 hours) or one-half of the test interval.

HPCS FAULT TREE DATA—CASE V

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DC	1.2E-06	365	13.5	4.5E-04	IEEE-500, PG. 81
DG2B				2.4E-02	CASE II
ECB03CO	1.7E-05	36	13.5	8.4E-04	PLANT DATA
ECB07CO	1.7E-05	36	13.5	8.4E-04	PLANT DATA
ECB2431O	3.4E-05	36	13.5	1.7E-03	PLANT DATA
ETR2431W	6.0E-07	36	13.5	3.0E-05	EGG-EA-5887, PG. 183
HCN004ON				1.0E-04	EGG-EA-5887, PG. 15
HCN004XN				1.0E-04	EGG-EA-5887, PG. 15
HCN015ON				1.0E-04	EGG-EA-5887, PG. 15
HCN015XN				1.0E-04	EGG-EA-5887, PG. 15
HCNK3N				1.0E-04	EGG-EA-5887, PG. 15
HCNK9N				1.0E-04	EGG-EA-5887, PG. 15
HCNK14PN				1.0E-04	EGG-EA-5887, PG. 15
HCV005P				1.4E-04	NUREG-1363
HCV016P				1.4E-04	NUREG-1363
HCV024P				1.4E-04	NUREG-1363
HMO004P				7.8E-03	NUREG-1363
HMO015P				7.8E-03	NUREG-1363
HMO023O	1.6E-07	365	13.5	6.1E-05	GE 22A2689
HOPHPCSX				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
HPCSMNT				5.0E-03	NEDO-31085
HPM001R	6.3E-06	365		2.3E-03	NRC 1205
HPM001S	9.7E-06		13.5	1.3E-04	NRC 1205
HRE004OZ				1.0E-04	EGG-EA-5887, PG. 15
HRE004XZ				1.0E-04	EGG-EA-5887, PG. 15
HRE015OZ				1.0E-04	EGG-EA-5887, PG. 15
HRE015XZ				1.0E-04	EGG-EA-5887, PG. 15
HREK14PZ				1.0E-04	EGG-EA-5887, PG. 15
HREK3Z				1.0E-04	EGG-EA-5887, PG. 15
HREK9Z				1.0E-04	EGG-EA-5887, PG. 15
HTR004W	6.0E-07	36	13.5	3.0E-05	EGG-EA-5887, PG. 183
HTR015W	6.0E-07	36	13.5	3.0E-05	EGG-EA-5887

[1] Detection intervals for components noted in this list are for one-half of the AOT (36 hours) or one-half of the test interval.

HPCS FAULT TREE DATA—CASE VI

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DC	1.2E-06	365	12	4.5E-04	IEEE-500, PG. 81
DG2B				0.0	OFFSITE POWER & DG AVAILABLE
ECB03CO	1.7E-05		12	2.0E-04	PLANT DATA
ECB07CO	1.7E-05		12	2.0E-04	PLANT DATA
ECB24310	3.4E-05		12	4.0E-04	PLANT DATA
ETR2431W	6.0E-07		12	7.2E-06	EGG-EA-5887, PG. 183
HCN0040N				1.0E-04	EGG-EA-5887, PG. 15
HCN004XN				1.0E-04	EGG-EA-5887, PG. 15
HCN0150N				1.0E-04	EGG-EA-5887, PG. 15
HCN015XN				1.0E-04	EGG-EA-5887, PG. 15
HCNK3N				1.0E-04	EGG-EA-5887, PG. 15
HCNK9N				1.0E-04	EGG-EA-5887, PG. 15
HCNK14PN				1.0E-04	EGG-EA-5887, PG. 15
HCV005P				1.4E-04	NUREG-1363
HCV016P				1.4E-04	NUREG-1363
HCV024P				1.4E-04	NUREG-1363
HMO004P				7.8E-03	NUREG-1363
HMO015P				7.8E-03	NUREG-1363
HMO0230	1.6E-07	365	12	6.0E-05	GE 22A2689
HOPHPCSX				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
HPCSMNT				5.0E-03	NEDO-31085
HPM001R	6.3E-06	365		2.3E-03	NRC 1205
HPM001S	9.7E-06		12	1.2E-04	NRC 1205
HRE0040Z				1.0E-04	EGG-EA-5887, PG. 15
HRE004XZ				1.0E-04	EGG-EA-5887, PG. 15
HRE0150Z				1.0E-04	EGG-EA-5887, PG. 15
HRE015XZ				1.0E-04	EGG-EA-5887, PG. 15
HREK14PZ				1.0E-04	EGG-EA-5887, PG. 15
HREK3Z				1.0E-04	EGG-EA-5887, PG. 15
HREK9Z				1.0E-04	EGG-EA-5887, PG. 15
HTR004W	6.0E-07		12	7.2E-06	EGG-EA-5887, PG. 183
HTR015W	6.0E-07		12	7.2E-06	EGG-EA-5887

[1] Detection intervals for components noted in this list for one-half of the test interval.

RCIC FAULT TREE DATA—CASE I

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DC	1.2E-06	365	6.5	4.5E-04	IEEE-500, PG. 81
DCB21040	1.5E-07	365	6.5	5.6E-05	NPRDS, GE PLANTS
DCB21050	1.5E-07	365	6.5	5.6E-05	NPRDS, GE PLANTS
RCICMNT				1.1E-02	NEDO-31085
RCN013CN				1.0E-04	EGG-EA-5887, PG. 15
RCN013ON				1.0E-04	EGG-EA-5887, PG. 15
RCN045CN				1.0E-04	EGG-EA-5887, PG. 15
RCN045ON				1.0E-04	EGG-EA-5887, PG. 15
RCNK2N				1.0E-04	EGG-EA-5887, PG. 15
RCNK5N				1.0E-04	EGG-EA-5887, PG. 15
RCV065P				1.4E-04	NUREG-1363
RCV066P				1.4E-04	NUREG-1363
RLUBEX	6.8E-05		6.5	4.4E-04	NUREG/CR-2802
RMO013P				7.8E-03	NUREG-1363
RMO0190	1.6E-07	365	6.5	5.9E-05	GE 22A2689
RMO045P				7.8E-03	NUREG-1363
RMO0460	1.6E-07	365	6.5	5.9E-05	GE 22A2689
RMO0630	1.6E-07	365	6.5	5.9E-05	GE 22A2689
RMO0640	1.6E-07	365	6.5	5.9E-05	GE 22A2689
ROPRCICX				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
RPM001R	1.2E-04	365		4.4E-02	NUREG/CR-2802
RPM001S	3.0E-05		6.5	2.0E-04	NUREG/CR-2802
RRE013OZ				1.0E-04	EGG-EA-5887, PG. 15
RRE045OZ				1.0E-04	EGG-EA-5887, PG. 15
RREK5Z				1.0E-04	EGG-EA-5887, PG. 15
RSTEAMX	1.3E-05		6.5	8.5E-05	NUREG/CR-2802

[1] Detection intervals for components noted in this list for one-half of the test interval.

RCIC FAULT TREE DATA—CASE II

Identifier	Lambda	Detection Interval[1]	Mission Time	Failure Data	Data Source
DC	1.2E-06	365	12	4.5E-04	IEEE-500, PG. 81
DCB21040	1.5E-07	365	12	5.7E-05	NPRDS, GE PLANTS
DCB21050	1.5E-07	365	12	5.7E-05	NPRDS, GE PLANTS
RCICMNT				1.1E-02	NEDO-31085
RCN013CN				1.0E-04	EGG-EA-5887, PG. 15
RCN013ON				1.0E-04	EGG-EA-5887, PG. 15
RCN045CN				1.0E-04	EGG-EA-5887, PG. 15
RCN045ON				1.0E-04	EGG-EA-5887, PG. 15
RCNK2N				1.0E-04	EGG-EA-5887, PG. 15
RCNK5N				1.0E-04	EGG-EA-5887, PG. 15
RCV065P				1.4E-04	NUREG-1363
RCV066P				1.4E-04	NUREG-1363
RLUBEX	6.8E-05		12	8.2E-04	NUREG/CR-2802
RM0013P				7.8E-03	NUREG-1363
RM0019O	1.6E-07	365	12	6.0E-05	GE 22A2689
RM0045P				7.8E-03	NUREG-1363
RM0046O	1.6E-07	365	12	6.0E-05	GE 22A2689
RM0063O	1.6E-07	365	12	6.0E-05	GE 22A2689
RM0064O	1.6E-07	365	12	6.0E-05	GE 22A2689
ROPRCICX				1.0E-01	OPERATOR ERROR (SCREENING VALUE)
RPM001R	1.2E-04	365		4.4E-02	NUREG/CR-2802
RPM001S	3.0E-05		12	3.6E-04	NUREG/CR-2802
RRE013OZ				1.0E-04	EGG-EA-5887, PG. 15
RRE045OZ				1.0E-04	EGG-EA-5887, PG. 15
RREK5Z				1.0E-04	EGG-EA-5887, PG. 15
RSTEAMX	1.3E-05		12	1.6E-04	NUREG/CR-2802

[1] Detection intervals for components noted in this list for one-half of the test interval.