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INVESTMENT RISK ASSESSMENT OF THE HTGR STEAM CYCLE/COGENERATION PLANT

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ABSTRACT

A probabilistic investment risk assessment has been performed on the Baseline 0 design of the 2240 MW(t) steam cycle cogeneration (SC/C) high-temperature gas cooled reactor (HTGR). The assessment shows that this plant can provide a high degree of assurance against extended plant outages and costly damage due to accidents. The assessment has also been compared to the investment protection goals recently developed for the HTGR and reflecting a strong aversion to long outage times. This comparison shows that, for the vast majority of the broad spectrum of events considered, the 2240 MW(t) SC/C HTGR meets these goals with varying degrees of margin. Furthermore, in those few, very low frequency events in which the goals are not met due to extended interruptions in core cooling, the assessment provides explicit guidance for improvements which can contribute to meeting the goals.

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1. SUMMARY

A probabilistic investment risk assessment has been performed on the Baseline 0 design of the 2240 MW(t) steam cycle cogeneration (SC/C) high-temperature gas cooled reactor (HTGR). The assessment shows that this plant can provide a high degree of assurance against extended plant outages and costly damage due to accidents. The assessment has also been compared to the investment protection goals recently developed for the HTGR and reflecting a strong aversion to long outage times. This comparison shows that, for the vast majority of the broad spectrum of events considered, the 2240 MW(t) SC/C HTGR meets these goals with varying degrees of margin. Furthermore, in those few, very low frequency events in which the goals are not met due to extended interruptions in core cooling, the assessment provides explicit guidance for improvements which can contribute to meeting the goals.

Figure 1-1 shows the assessed investment risk envelope for the 2240 MW(t) SC/C HTGR along with an investment risk goal proposed by GA Technologies Inc. (GA). The envelope is defined by primary coolant leaks at higher frequencies, by loss of liner cooling in the mid-frequency range, and by interrupted core cooling at low frequencies. The dominant scenarios for each of these initiating events are summarized briefly below.

The dominant primary coolant leak scenario is characterized by instrument line failures or moderately sized leaks in prestressed concrete reactor vessel (PCRV) penetrations. These leaks are estimated to vent 20% to 75% of the radiocontaminated primary coolant inventory to the containment building before they can be stopped. Such a leak has been assessed to occur at a mean frequency of about once in thirteen reactor years and has a mean consequence of one month of plant downtime.

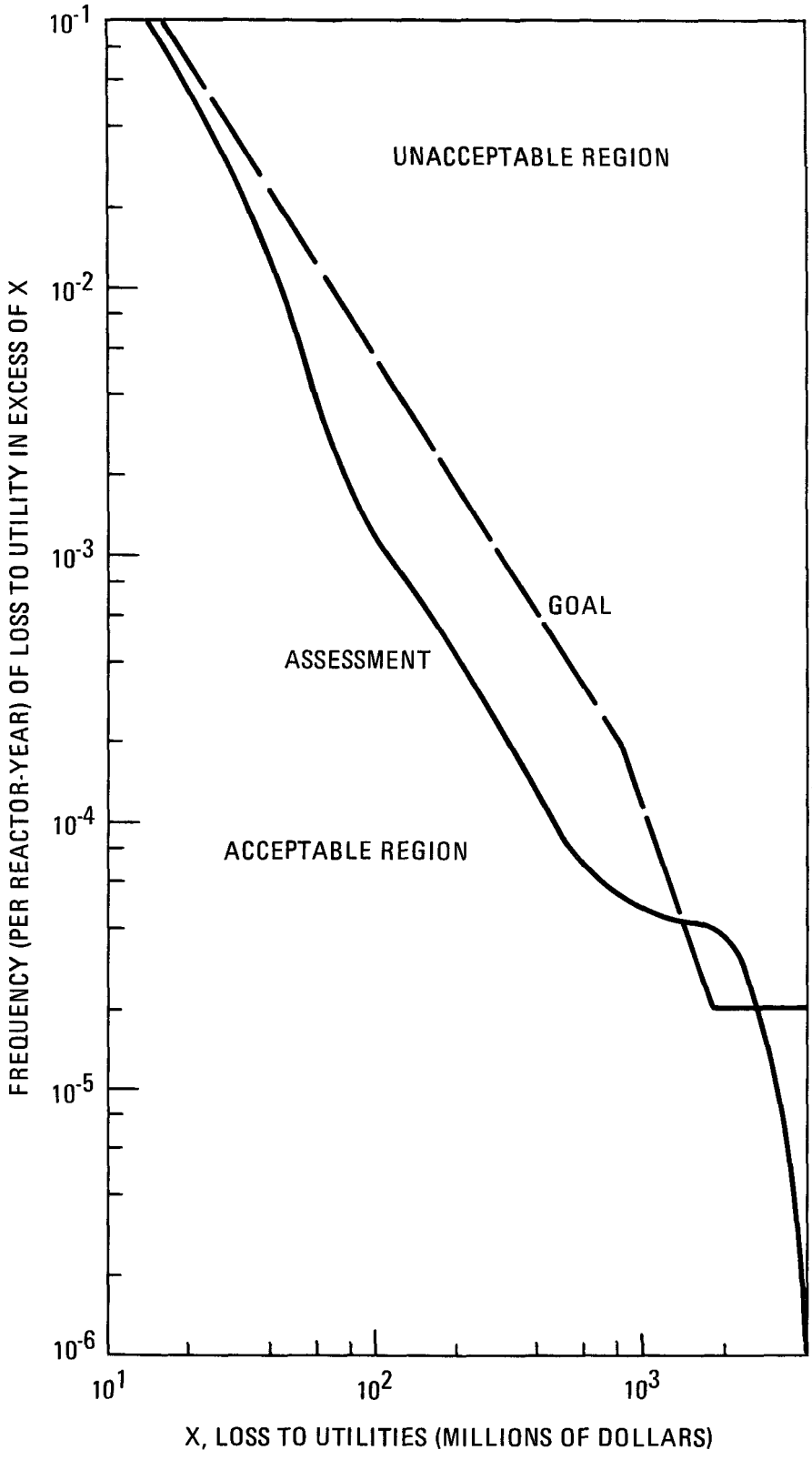

Fig. 1-1. Overall investment risk curve compared with investment protection goal proposed by GA Technologies Inc.

The dominant liner cooling failure scenario involves a loss of PCRV liner cooling which, by timely shutdown and cooldown of the plant concrete, averts any permanent damage. However, because the severe environment temperature limit for concrete is exceeded, a four-month outage is predicted during which time continued PCRV integrity is demonstrated to the satisfaction of both the plant operator and regulating agencies. The mean frequency of occurrence for this event is once in three hundred reactor years.

The highest consequence interrupted core cooling scenario includes several events that are of sufficient duration to preclude repair and restoration of the nuclear heat source to service. The mean frequency of occurrence for this scenario of events is once in thirty thousand reactor years. The consequences are comparable to completely replacing the nuclear heat source and an equivalent mean downtime of 8.4 years. It is only these extended interruptions in core cooling leading to a nonrepairable loss of the nuclear heat source, that are significant in defining the risk envelope. All other interrupted cooling scenarios involving repairable damage are negligible contributors.

Regarding the goal in Fig. 1-1, GA and others have addressed investment risk by developing quantitative investment protection goals against which evolving plant designs may be judged with respect to their investment protection adequacy. Two investment related goals are presented in this report and require some explanation. At the time this assessment was done GA had proposed an investment risk goal which was intended to limit dollar losses to the owner of an HTGR from unlikely or low probability events. It is this goal against which the assessment is compared in Fig. 1-1. More recently, the Department of Energy (DOE) sponsored HTGR Safety and Investment Protection Working Group has issued its own investment protection goal. While this more recent goal has similar characteristics to the GA proposal, it has expanded scope and is quantified in outage days rather than dollars lost. A graphical interpretation of this goal is compared with the assessment in Fig. 1-2.

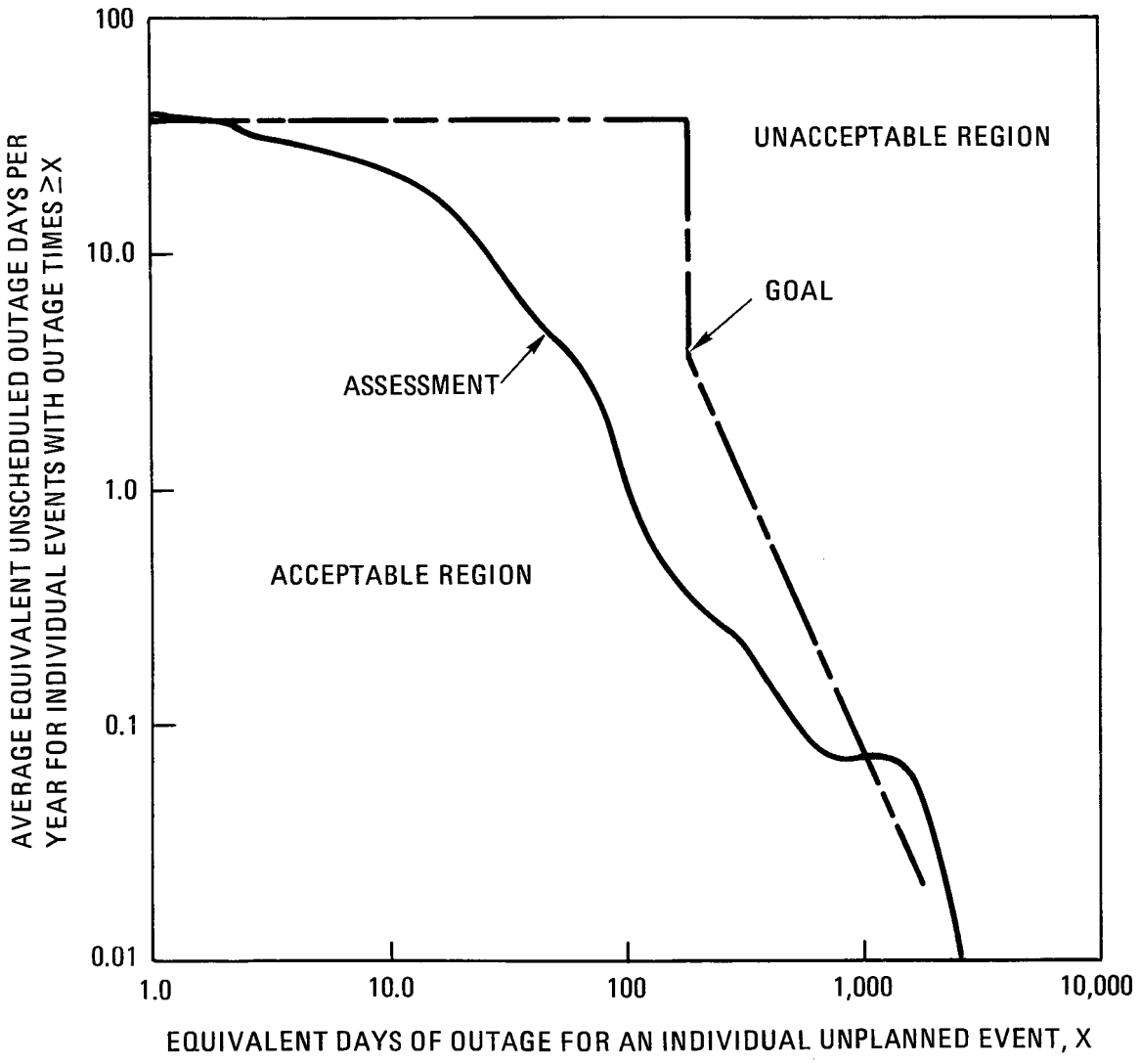

Fig. 1-2. Comparison of assessment with investment protection goal of the safety and investment protection working group

As with the comparison to the GA goals, the DOE sponsored goal is not met in the highest consequence region of the assessment, where the risk is dominated by extended interruption of core cooling scenarios. These scenarios are dominated by a sequence of events beginning with a loss of main loop cooling in which a failure of the balance of plant (BOP) leads to an orderly plant shutdown, followed by a limited period of shutdown cooling using the main loops. Following the limited shutdown cooling, the auxiliary heat removal system (AHRS) fails to start, and repair efforts are unsuccessful before extensive overheating of the core occurs.

This violation of the high consequence portion of the DOE Risk-Consequence goal by interrupted cooling scenarios is noteworthy. Severe accidents have been studied in a quantitative manner for several years in both the context of safety and investment risk. The event sequences involving loss of main loop cooling and inability to restore either the main loops or AHRS have been identified in every risk assessment since the Accident Initiation and Progression Analysis (AIPA) study in 1978 as dominating the frequency of cooling losses. Because of this, several enhancements to core cooling reliability have already been incorporated into the design, providing the HTGR with significant safety margin and investment protection against core cooling losses that exceed that of the existing nuclear industry.

However, the current trend in investment protection, as exemplified by both the GA and the DOE goals, includes a very restrictive aversion to irreparable damage. This assessment suggests that with the current design of the 2240 MW(t) SC/C HTGR meeting these aversion criteria may require additional design modifications. Nonetheless, this study shows the HTGR to be exceptionally forgiving of a wide range of upset and accident conditions.

2. INTRODUCTION AND OBJECTIVES

2.1. PROGRAMMATIC OBJECTIVES

The ultimate objective of the HTGR program is the production of safe, economical power as enunciated in the Overall Plant Design Specification (OPDS, Ref. 2-1). The major activities in accomplishing this are design, construction, operation, maintenance, and decommissioning. All of these activities need to be done well to achieve a low economic risk.

The ultimate objective is categorized into four top level goals. Goal 1 emphasizes economic design, construction, and normal operation including scheduled outages. Goal 2 emphasizes investment protection including unscheduled outages. Goals 3 and 4 emphasize safety.

Part of investment protection is provided by limiting investment risk, which, in this usage, is the avoidance of accidents that would have severe financial impact, such as the financial difficulties suffered by General Public Utilities (GPU) because of the accident at Three Mile Island. These events, with severe consequences but low frequencies, need to be systematically studied with techniques which can treat sequential and multiple failures and use field experience in their formulations. Probabilistic risk assessment is the principal tool for this. It has been and is being used for safety risk assessments and for investment risk assessments in the HTGR program.

The risk analysis provides an interface between the top level goals, which are quantified, and the design process. A schematic of this process is shown in Fig. 2-1. It, of course, shows only a small part of the overall design effort since the figure concentrates on the interaction with the risk assessment and some of the quantified goals.

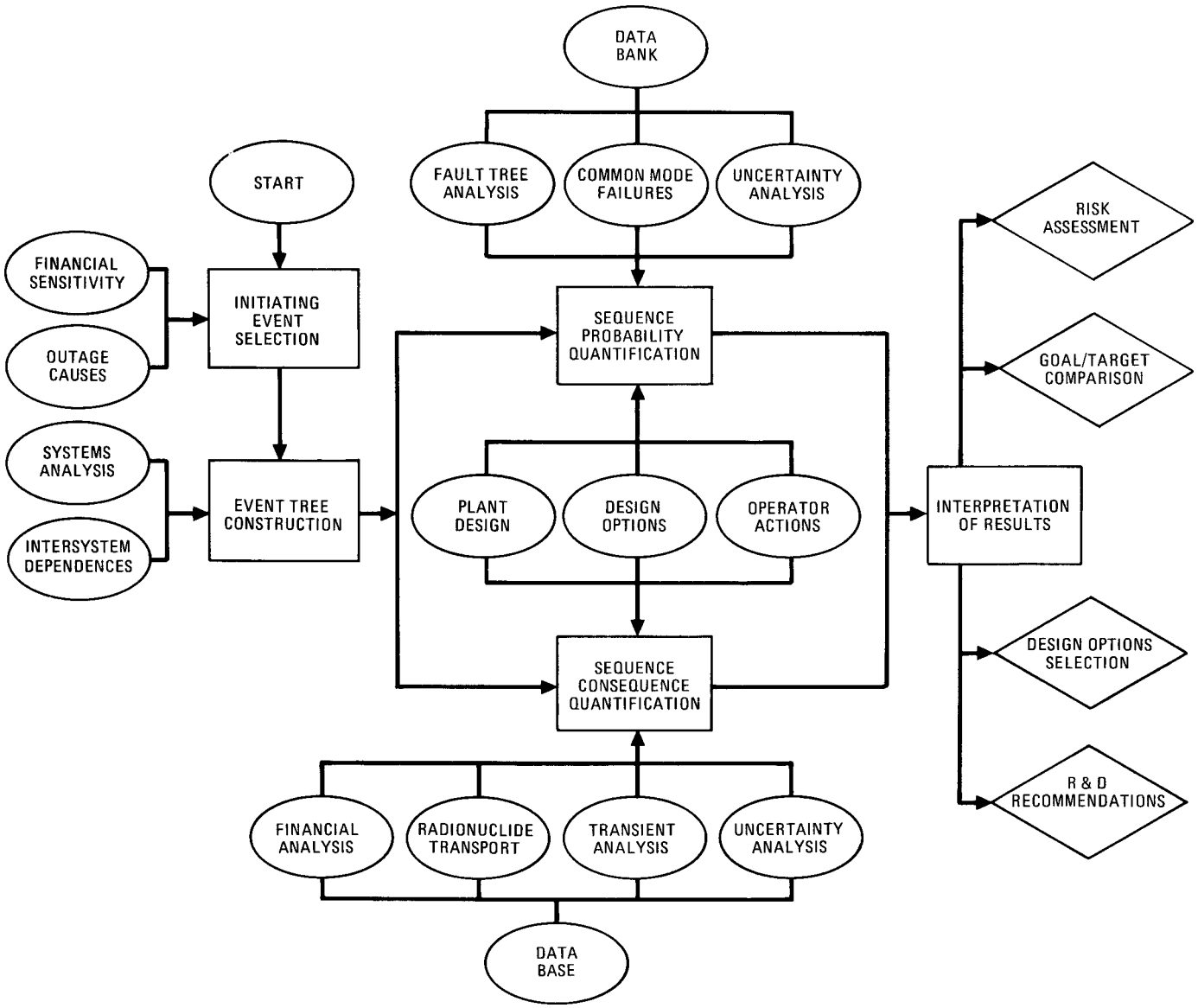

Fig. 2-1. Interfaces for integration of risk analysis and the design process

The results of assessments of an initial plant design are compared to goals to find if the goals are satisfied or to determine how great the improvements should be and where the design might best be modified. This allocation process provides reliability requirements, some of which are governed by the goal of limiting investment risk. Design options are then considered in more detail, if necessary, in order to go through the tradeoffs to arrive at an improved design. This process may be repeated at each design phase, such as in preliminary design, as a part of limiting investment risk in the operating plant.

The knowledge of risks and of the design that is gained is also used in licensing and in establishing and satisfying design data needs, as indicated on Fig. 2-1.

The process is documented and coordinated in an organized way as indicated in Fig. 2-2. The OPDS is shown at the top of the diagram, and this report on the plant investment risk assessment is shown toward the lower middle. The assessments also support functional analysis of the power plant design as shown toward the upper left.

2.2. RISK ASSESSMENT OBJECTIVES

There are a number of primary objectives for any risk assessment. The assessment should:

Be systematic in that the relations of events to each other in an accident can be clearly seen, and that the range of alternatives in the stages of an accident are evident.

Include quantitative estimates of likelihoods or probabilities in such a way as to make coherent probabilistic statements.

Strive for a balanced completeness in failure modes and in particular should not exclude significant cases of multiple failures.

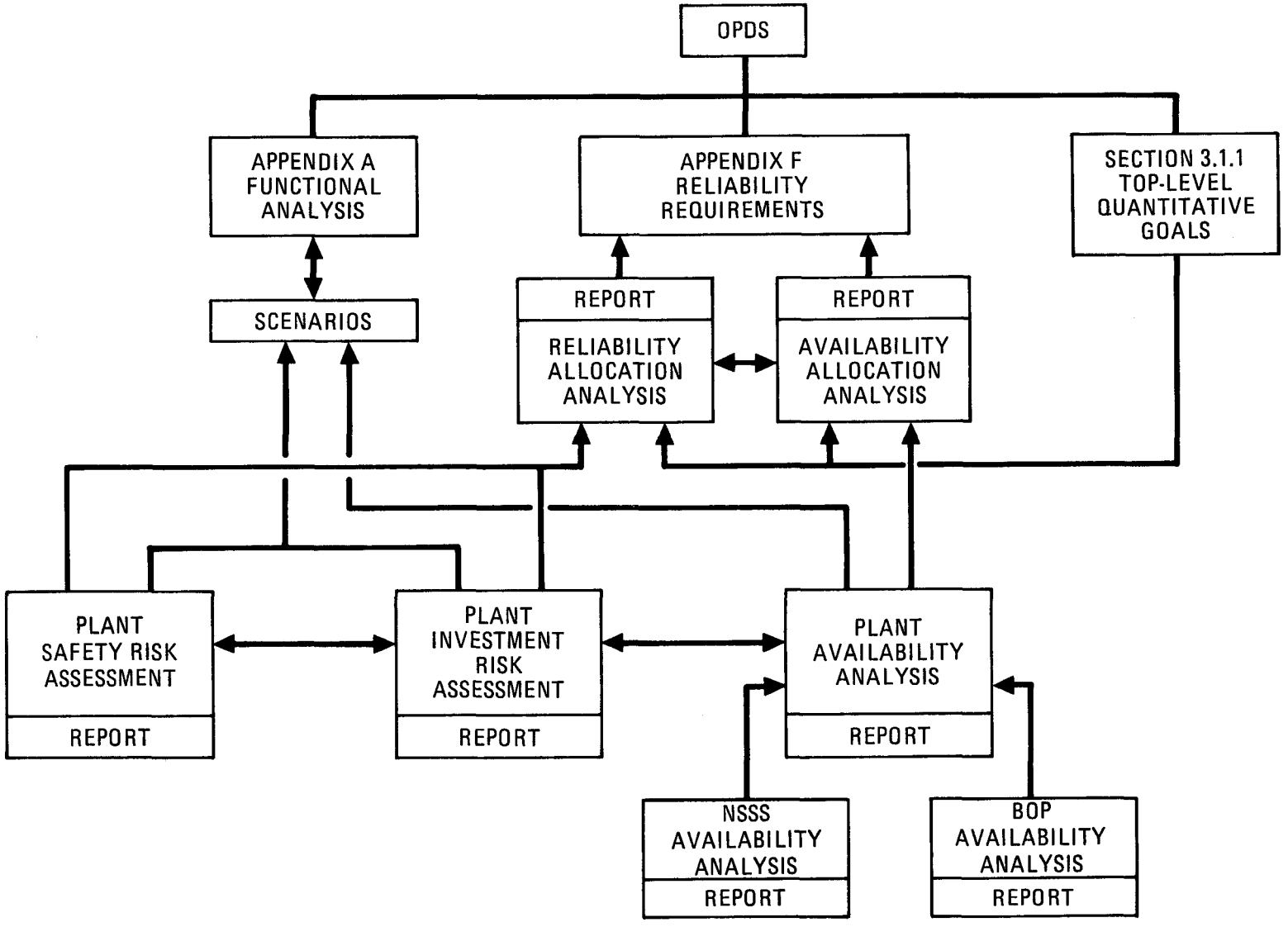

Fig. 2-2. Relationships of plant probabilistic activities

Assess physical phenomena on a realistic basis and should not use conservatisms which violate physical laws.

Deal explicitly with statistical uncertainties.

The resulting analyses should provide technical insight regarding accidents important to investment risk. This includes the kind of accident, the equipment involved, the degree of radioactive contamination, the extent of damage, the length of downtime, and the amount of financial losses. These results are a starting point for considering any design options which may be important. The results also contribute toward the technical basis for showing that the power plant will meet the goals for limiting investment risk.

2.3. INVESTMENT RISK BACKGROUND

Probabilistic Risk Assessment has been important in the studies of HTGRs since February 1974. During this time, most of the emphasis was placed on safety analyses.

With the occurrence of the accident at Three Mile Island II, an interest developed in the investment risk in nuclear power plants from the possibility of rare but severe accidents. Families of accidents which are not expected to happen in the life of a single plant are emphasized under investment risk.

Studies on investment risk actually began for the HTGR in 1980. A series of studies was performed and a list of these is given in Table 2-1.

The assessments are listed first in the table. In 1980, the first study that was performed (Ref. 2-2) consisted of a risk assessment that was primarily done in order to demonstrate and develop the methodology for the investment risk frequency and consequence analysis. A series of more detailed analyses were then done in 1981 which included screening

TABLE 2-1
SUMMARY OF GA INVESTMENT RISK ACTIVITIES

Description	Year
Assessments	
Initial investment risk assessment	1980
Screening for potential risks	1981
Investment risks related to core heatup coolant leaks	1981
Risk due to primary coolant leaks	1981
Risk related to loss of PCRV liner cooling	1981
Investment risk summary and recommendation for improvements	1981
Effect of enhanced safety features on investment risk	1981
Summary of studies	1982
Modular reactor system investment risk	1983
Methodology	
Method for choosing reliability criteria	1980
Economic consequence model	1982
Investment risk methods	1982
Consequence uncertainty methods	1983
Goals	
Quantitative goals for investment risk	1980
Quantitative goals	1980
Investment risk targets	1983
Investment protection goal	1984

for a variety of risks and provided more detail on risks related to core heatup, primary coolant leaks, and loss of PCRV liner cooling. These were summarized in (Refs. 2-3 and 2-4) two reports in 1982. In addition, at this point recommendations were made for improvements to the design. Two other aspects of prior assessments are a study of the effect of enhanced safety features on the investment risk and an investment risk study on the modular reactor system.

The methodology for this work, of course, borrowed heavily from the methodology for safety risk. A different aspect, though, was the requirement for a model for economic consequences which was developed specifically for the studies. Additional methods were also developed for investment risk applications.

The goals for investment risk have developed slowly over the years starting with a tentative goal that was not published, although it was referred to indirectly in a report on quantitative goals in 1980 (Ref. 2-5). Since then, however, a more complete development of the idea of investment goals has been accomplished (Refs. 2-6 and 2-7).

2.4. REPORT CONTENTS

The remainder of this report provides a technical background and presents details of the analyses of the investment risk for the 2240 MW(t) SC/C plant.

Section 3 describes the methodology needed for probabilistic investment risk analysis, particularly event tree construction and the resultant frequency and consequence assessment procedures and techniques which form the basis for the quantification of financial risk. Section 4 describes two investment risk goals. Section 5 gives a brief plant description, with emphasis on those portions of the plant important to investment risk. Section 6 presents the frequency assessment of the investment risk events, along with a brief discussion of the supporting data base, and important uncertainty considerations. Section 7

discusses the consequence evaluation in terms of physical phenomena and financial impact on plant owners or sponsors, and briefly refers to the supporting data base and uncertainty considerations. Section 8 presents the results. Risk plots of the dominant initiating events and their contributions to the overall investment risk envelope of the 2240 MW(t) SC/C plant are provided, as well as a discussion of the key plant hardware and event scenarios which govern the financial risk of the plant. Sections 9 and 10 present references and acknowledgements, respectively. Appendix A provides data on frequencies, while Appendix B discusses the economic model used to evaluate financial risk for the plant. Appendix C documents the data used to compare investment risk to the most recent goal.

2.5. REFERENCES

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3. INVESTMENT RISK ASSESSMENT METHODOLOGY

Methodology for the analysis of probabilistic investment risk is fundamentally the same as that for the analysis of probabilistic safety risk. However, there are some differences. The most significant difference between safety and investment risk manifests itself in the realm of consequence analysis. Where safety risk is primarily concerned with radioactive fission product release, investment risk focuses on the economic loss due to extended plant downtime, plant damage and repair, and decontamination.

A brief overview of the investment risk methodology is presented in Section 3.1. Section 3.2 specifically addresses frequency quantification methodology, including initiating event evaluation, event tree construction, fault tree analysis, and common mode failures. Section 3.3 presents details concerning consequence quantification, including transient thermal response, component damage evaluation, decontamination, and economic modeling. Sections 3.4 and 3.5 discuss data base and uncertainty analysis, respectively.

3.1. OVERVIEW OF METHODOLOGY

The assessment method for investment risk is shown in Fig. 3-1. The method is begun by selecting initiating events and then continued by constructing event trees for accident sequences, analyzing the sequences of events to obtain the probabilities and to evaluate the financial consequences of damage and the spread of radioactivity, and finally providing risk plots interpreting the results.

Initiating events that have the potential to lead to damage of the plant and the spread of radioactivity are selected on as broad and rational a basis as possible. Once the initiating events are defined, a

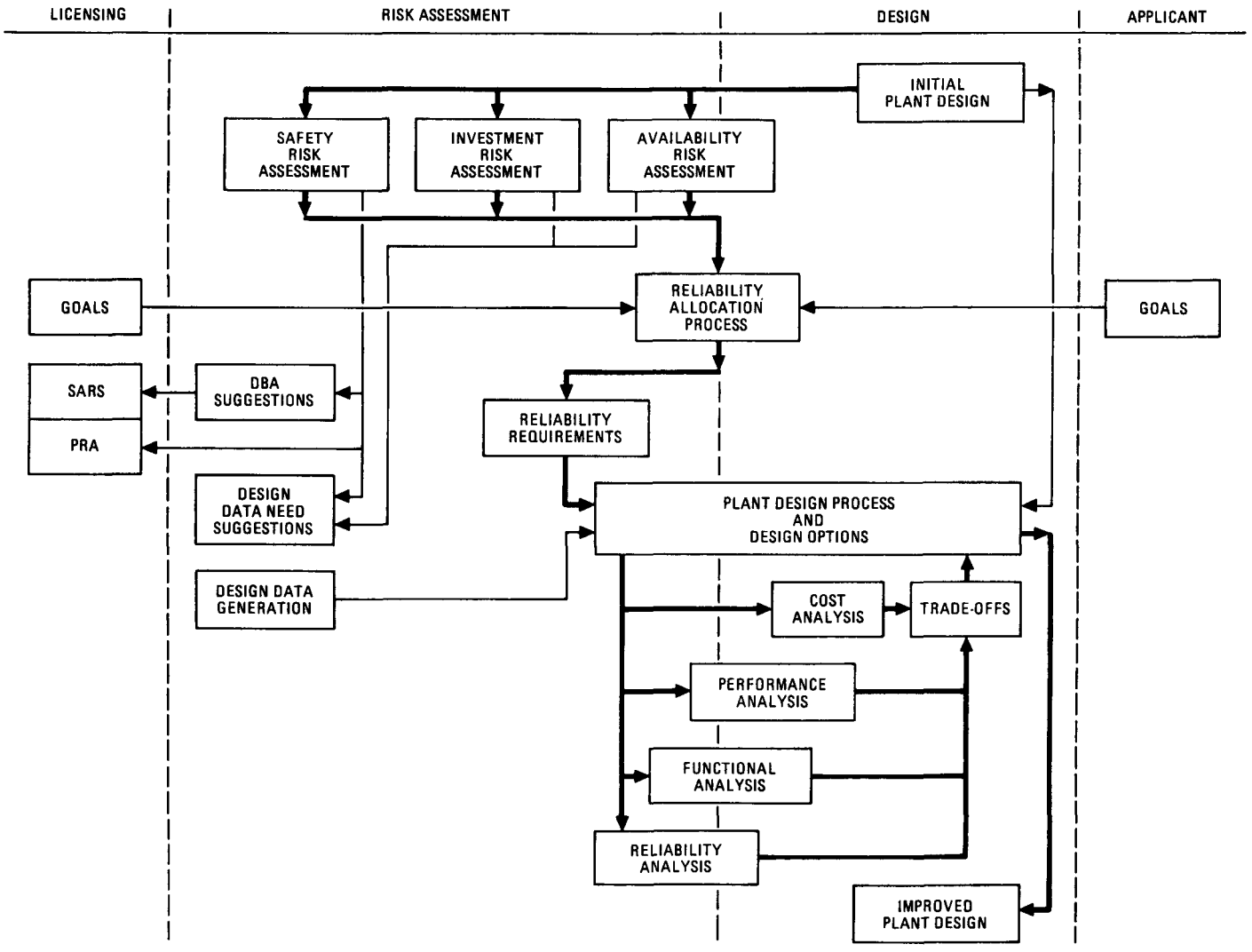

Fig. 3-1. Investment risk assessment methodology

systematic presentation of the progression of the accident sequences from initiation to termination is provided in an event tree for each family of initiating events. To anticipate and understand these sequences, systems analysis is needed to show the transient response such as for core temperatures, and to know the response of active systems such as the ability of the auxiliary cooling to remove the decay heat under the conditions specified in the accident sequence. Intersystem dependences may also be important.

The probability of occurrence of each event along each of the accident sequences within the event tree is often obtained from fault tree analysis. A fault tree is a logic diagram which gives the probability of an undesired state of a system (e.g., loss of main loop cooling) when the various component failure modes, probabilities, and dependences are known. The component failure probabilities come from data banks containing standardized reliability values and/or raw experience data. In the evaluation of fault trees it is important to consider common mode failures which can lead to simultaneous failure of redundant components or systems. Uncertainty analysis allows the generation of mean values for probabilities of accident sequences.

Quantification of the consequences of a sequence involves the evaluation of the transient conditions in the plant as a function of time, the assessment of component damage resulting from such a transient, and the estimation of the downtime and direct costs that would be incurred by a utility to recover from such damage. Calculation of the transient thermodynamic behavior of the plant, such as transient temperatures, pressures, and flows, is typically done for the core and PCRV, in order to determine the extent of damage incurred by components in the PCRV. Energetic events, such as rotating machine failure and seismic occurrences, are also assessed for their impact on the plant.

In the event that component damage is indicated, the extent of the damage is estimated based on the material component limits and licensing restrictions placed on the plant. Cost is estimated based on

accessibility, availability of replacement parts, and repair times for the components incurring damage.

The analysis of financial consequences and physical phenomena for the accident sequences is simplified by grouping the sequences into a smaller number of categories such that the initiating events and the system responses of sequences within a given category are very similar and therefore result in about the same consequences. Given a category, the damage caused by the initiating event and/or system response is determined for key components or structures. Any release of radionuclides is calculated. Repair and decontamination times are estimated as part of estimating downtime. Costs and financial losses are then calculated. Uncertainty analysis allows the drawing of the customary cumulative curve which shows financial consequences typically increasing as probabilities get lower.

As Fig. 3-1 shows, interpretation of the results for probability and consequence allows the investment risk assessment to be conveniently presented such as in risk plots. The assessed risk of the plant is compared to goals and targets. This comparison is useful as an aid in selecting between various design options and R&D recommendations. The design options could provide margins between the predicted risk of the plant and the targets and/or goals. This portion of justifying design change therefore makes an choice of goals and targets important.

3.2. FREQUENCY QUANTIFICATION

The objective of frequency quantification is to determine the frequencies of accident sequences that have been identified in event trees. Various methodologies are involved including initiating event selection, fault tree analysis, common mode failure theory, time dependent probability calculus, and human operator reliability. Several of these methodologies are discussed below beginning with initiating event selection.

3.2.1. Initiating Event Selection

Initiating event selection is essentially a gleaning process to provide a complete, broad, rational list of initiating events while at the same time setting aside those events which are not likely to significantly contribute to investment risk. Several approaches can be taken to identify accident initiating events (Ref. 3-1), including master logic diagrams and comprehensive engineering evaluation. The latter, as applied in this investment risk assessment, takes into consideration information from previous risk assessments, extensive operational data, and plant-specific design. In addition, the impact of some intersystem dependences as well as common mode failures are considered with respect to initiating events.

3.2.2. Event Tree Construction

Once an initiating event is defined, an event tree is constructed to identify all the variations on the progression of the event from initiation to termination. The event tree will show the sequences of events that may occur following the initiating event. It provides for the possibility that some events may or may not occur, and that the likelihood of their occurrence or nonoccurrence can be described by probabilities. In order to evaluate the sequence of events and the associated probability of occurrence, it is necessary to understand the plant design, the transient responses to plant disturbances, and the specific actions performed singly and in tandem by the plant systems, including human interaction. Because multiple systems will be involved in many sequences, their interdependences must be accounted for in the event tree. For example, the loss of both off-site power and the main turbo-generator set early in the sequence of the event tree will result in the shutdown of the main loop cooling system.

The construction of an event tree is begun by identifying a sequence of actions described in column-wise fashion at the top of the tree. The first branch of the tree consists of the most likely

progression of events to follow the initiating event. Additional branches of the tree are developed by considering the alternative outcomes of each probabilistic event in the first sequence, beginning with the last event. In many cases this is simply the probability the event fails to occur. The dependences between events limit the tree to only those event sequences which can realistically occur. After all proper combinations of events have been considered, the event tree is complete.

In a very simple example, an initiating event could be followed by a corrective action, thereby terminating the accident sequence. This is illustrated by sequence A, or branch A, in Fig. 3-2. If the corrective action, event 2 of Fig. 3-2, did not occur, and there was backup equipment which could respond to the accident as event 3, the success of the event would yield branch B. The failure of the backup equipment to respond is also accounted for in the tree with an additional branch. A more complete description of how to construct an event tree is given in Ref. 3-2.

Event tree quantification requires that each node in the tree have its probability determined. The sequence frequency designated F(C), corresponding to branch C of Fig. 3-2, can be examined as an example. F(C) is expressed as:

$$F(C) = F(1) \cdot P(\overline{2}\ 1) \cdot P(\overline{3}\ 2,1) \quad , \tag{3-1}$$

where $F(C) \triangleq$ = sequence frequency for branch C,

$F(1) \triangleq$ = frequency that event 1 occurs,

$P(\overline{2})\ 1) \triangleq$ = probability that event 2 does not occur, given that event 1 occurs,

$P(\overline{3}\ \overline{2},1) \triangleq$ = probability that event 3 does not occur, given that event 2 does not occur, and that event 1 occurs.

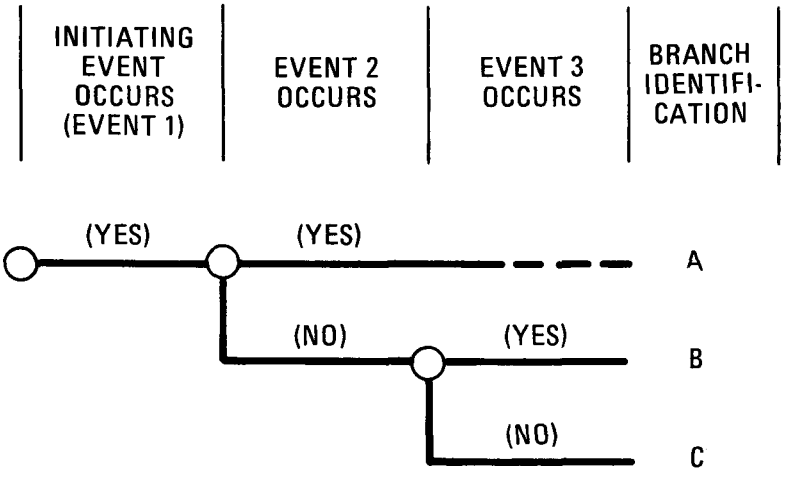

Fig. 3-2. Example of event tree

Each of the two P terms on the right side of Eq. 3-1 is termed a branch point probability since it is associated with a branching point on the event tree. Note that each branch point probability depends on the outcome of branch points preceeding it in the sequence.

3.2.3. Fault Tree Analysis

The branch point probabilities can be computed with fault trees. A branch point event may typically be the occurrence of adequate operation of a system or failure of that system. A fault tree is used to analyze failure of a system by displaying the failures of the components of the system and their logical inter-relationships which lead to system failure. This result is easily used to obtain the probability of system success.

A typical fault tree is shown in Fig. 3-3. This sample tree is for an equipment train for a large HTGR containment recirculation cleanup system. The tree can be used to calculate the probability that equipment train number 1 fails at a time and under conditions specified by the branch point in the event tree where the answer will be used. The logic gate known as an 'OR' gate is shown as G6. It means that the equipment train will fail if there is no electric power or if there is failure of the circulation fans or if one of the three other indicated events (X_1, X_2, and X_5) occurs. However, circulation fan failure causing equipment train failure can only occur if both fan A and fan B fail. This is indicated by the logical 'AND' gate, which is shown below the fan-failure rectangle. The probabilities chosen as input to such a tree of course have to be consistent with the accident conditions found at that point in the event tree.

Evaluation of the probability of the top event is based on multiplying the probabilities of events that combine in an 'AND' gate

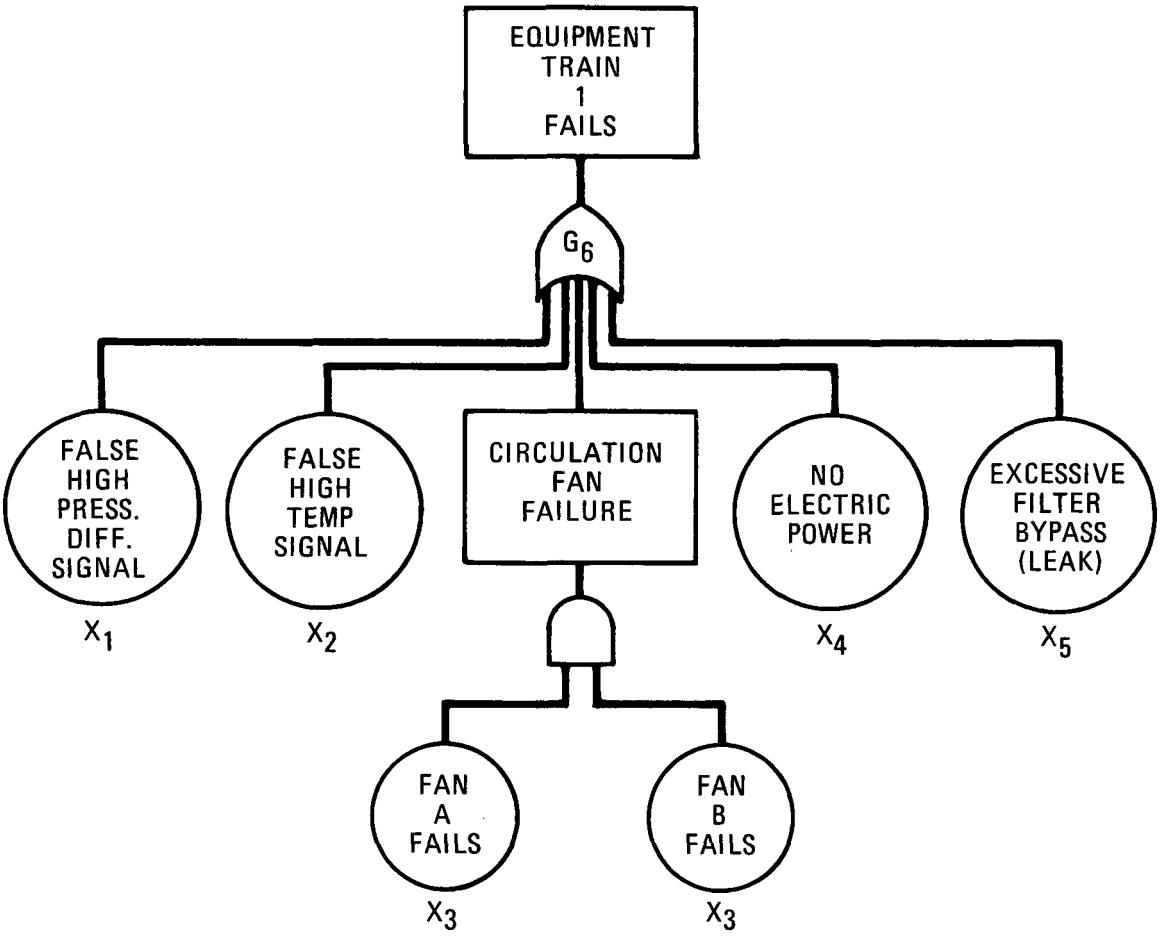

Fig. 3-3. Fault tree for equipment train for recirculation cleanup system

adding the probabilities that combine in an 'OR' gate. Thus, the fault tree in Fig. 3-3 would be quantified as:

$$F(G6) = F(X1) + F(X2) + F(X3) \cdot F(X3) + F(X4) + F(X5) \quad , \qquad (3\text{-}2)$$

where $F(X) = 1 - e^{-\lambda t} \approx \lambda t \triangleq$ the probability that a component with failure rate λ fails to operate for t hours, or

$F(X) = Q \triangleq$ the probability that a component with a demand probability Q fails to operate on demand.

3.2.4. Common Mode Failures

In many cases, common mode failures of similar equipment in redundant systems are sufficiently important that they must be modeled in the fault trees. Some types of common mode failure of a redundant system are treated explicitly in the fault trees, such as in Fig. 3-3. In that figure, it is seen that lack of electric power or presence of false signals regarding pressure differential and temperature can cause the train to fail, because those events cause both fans to be shut down. In other cases where common mode failure data are available for the system or where the significant common failure modes are more difficult to know in adequate detail, another technique of common mode analysis known as the Beta-factor method is employed. The factor Beta (β) is the ratio between the common mode failure rate of all similar redundant components in a system and the total failure for a single one of those components.

Systems are frequently designed which employ redundancy techniques to achieve high reliability. The important criterion in a decision on the application of redundancy is determined by the reliabilities of the subsystems from the whole system. Redundancy can either be standby or active; uniform or diverse. The simple general form of a redundant system is illustrated in Fig. 3-4 from Ref. 3-2. Complex systems can consist of many combinations of this simple form.

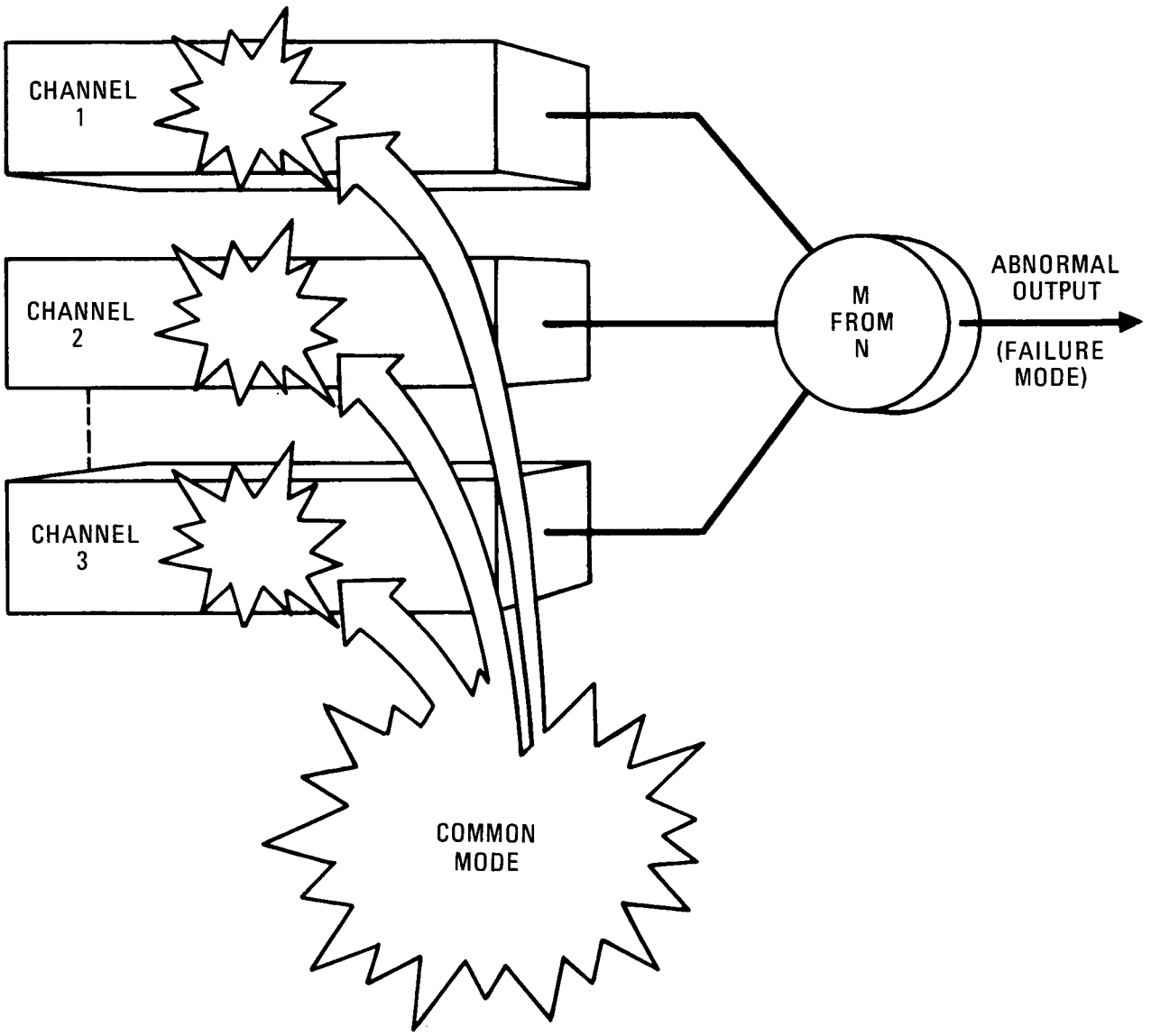

Fig. 3-4. Common-mode failure concept

Systems using redundancy techniques can tolerate a certain number and/or type of independent failures while continuing to maintain the required relationship between input and output conditions, but operating experience of redundant systems has shown that, even when the systems are designed with the intent of independence, system failure modes known as common modes occur, which lead to system failure more frequently than predicted under the independence assumption. The result is that the system has an abnormal output state (or failure mode) as illustrated on Fig. 3-4.

3.2.5. Time-Dependent Probability Calculus

Although many of the branch point probabilities can be expressed in terms of system reliability (or availability), events that require special modeling frequently appear in the event tree. One example that requires special treatment is a branch point event that is the intersection of two events, the probabilities of which are dependent on time. Consider the event "successful main loop cooling until offsite power is restored." The probability of successful main loop cooling is time-dependent since it depends on how long the system must operate. This time, in turn, is dependent on when offsite power is restored. The desired probability can be derived in terms of the probability density functions for the two (sub)events.

For instance, the reliability of the main loop cooling system $R_{ML}(t)$ can be expressed as:

$$R_{ML}(t) = \int_t^\infty f(x)dx \quad , \tag{3-3}$$

where $f(x)dx$ is the probability density function for failure of the main loops. We may defined a second probability density function for restoration of offsite power. The term $g(t)dt \triangleq$ the probability that offsite power is restored in the interval $(t, t + dt)$. Assuming that offsite power restoration and main loop cooling system failure are independent,

the probability that the main loops operate until offsite power is restored, P, is given by:

$$P = \int_0^\infty R(t)g(t)dt \quad , \tag{3-4}$$

where $R(t)g(t)dt \triangleq$ the probability that the main loops operate and offsite power is restored in the interval (t, t + dt). Details of how equations such as 3-4 are implemented in actual analyses are given in Ref. 3-1 and demonstrated in Section 6.

3.3. CONSEQUENCE QUANTIFICATION

The quantification of accident sequence consequences begins with analysis of the physical phenomena that occur during various accident sequences, along with an evaluation of the resulting damage to the plant. To arrive at a quantitative estimate for the investment risk of the accident scenario, the damage is subsequently evaluated from the standpoint of financial impact on the plant utility or owner in terms of unrecovered costs.

3.3.1. Transient Thermodynamic Response

The response of the primary coolant system to the core heatup scenarios has been modeled using a combination of computer programs, each of which analyzes different aspects of the problem. During the initial hours of the transient, when the PCRV is pressurized and natural convection is the dominant heat transfer mechanism, the RATSAM code (Ref. 3-3) is used in conjunction with the RECA code (Ref. 3-4). The RATSAM code models the entire primary coolant system whereas RECA models primarily the core. After PCRV depressurization through the relief valves occurs, radiation and conduction heat transfer are more important than natural convection, and the CORCON (Ref. 3-5) code is used to model the core cavity.

The RATSAM program has been developed to evaluate the transient thermal and fluid flow behavior of the primary coolant system in the HTGR under accident conditions. Given an appropriate forcing function, the program calculates the time-dependent pressure, temperature, and flow throughout the primary coolant system, taking into account the dynamic behavior of the helium circulators and associated valves, the automatic actions of the plant protection systems, and the heat transfer between the coolant, core, and steam generators.

The primary system is modeled as a number of fixed control volumes (or nodes), linked to each other by flow paths. A geometric description and an appropriate set of initial conditions are provided. The RATSAM program then applies the conservation laws of mass, energy, and momentum, the equation of state, and other relationships to each control volume and fluid flow path to compute the transient parameters of interest.

Starting with initial conditions corresponding either to normal full-power operation or to shutdown cooling, a core heatup transient is simulated by tripping the circulators to initiate the transient. After the circulators brake to a stop, closure of the main helium shutoff valves is simulated by increasing the resistance of the appropriate flow paths. The heat capacity of the secondary side is assumed to vary with temperature for the initial volume of water and steam in each steam generator. The system boundary is taken to be adiabatic beyond 4 in. of PCRV concrete.

Convective heat transfer in the side cavities and core plenums is modeled from the primary coolant to the PCRV thermal barrier cover plates. Conduction has been incorporated from the cover plates through the Kaowool insulation and PCRV liner to the PCRV concrete. Liner cooling operation can be simulated by holding the PCRV concrete temperature at the temperature of the liner cooling water. An inoperative liner cooling system can be simulated by allowing the PCRV concrete

temperature to change as heat is absorbed. Convection is also modeled to the secondary coolant tubes, and to the steam as a function of quality.

The RATSAM model of the core is limited; only two coolant paths are simulated, and conduction to the side reflectors is neglected. Therefore, an iterative scheme has been developed to utilize the more detailed core model of the RECA code. With the net core flows and system pressure generated in RATSAM, core temperatures in every region and level of the core are calculated in RECA. RECA considers the heat transfer mechanisms of conduction, convection, and radiation within the core. By using RECA with RATSAM, the heat capacity of the side reflectors is included in the assessment of the transient core temperatures. The core temperatures are input into RATSAM to re-evaluate the primary system response. The effect of the iteration between the RATSAM flows and pressure and the RECA core temperature is a more realistic model.

During a core heatup event, redistribution and conduction of decay heat generation cause core surface temperatures to rise. After PCRV depressurization, heat transfer from the core is primarily by radiation to the cooler PCRV surfaces.

For extended heatup, a version of the CORCON computer code (Ref. 3-5) has been developed to model PCRV failures while simultaneously calculating the heat transfer within the core and away from the core surfaces to the PCRV. A two-dimensional, cylindrical PCRV heat transfer model is used. Adiabatic conditions are imposed at all boundaries of the system. Within the model boundaries, the active heat transfer mechanisms are decay heat redistribution, conduction, and radiation.

3.3.2. Component Damage

Component damage is determined during a core heatup by evaluating when component temperatures exceed specified damage limits. Control rod

damage is determined from core temperatures calculated in RECA. Fuel failure is assessed using CORCON-generated core temperatures. Damage incurred by metallic components just above the core, such as plenum elements and region flow control orifices, is assessed using RECA thermal results. Damage to upper plenum thermal barrier is assessed utilizing information provided by both RECA and CORCON. Lower side-wall thermal barrier damage is evaluated based on CORCON calculations, as is PCRV liner and concrete damage.

RATSAM analyses are used to determine if and when the PCRV pressure relief valve will open and allow primary coolant to enter the reactor containment building. RECA is used to determine the time after which restoration of cooling will not preclude release of appreciable radioactivity from the fuel. (This time is termed MTRC, the maximum time to restore cooling.)

Component damage following seismic events is estimated based on the designed resistance of a structure or piece of equipment to earthquake induced ground motion. Damage due to turbomachinery failures is estimated based on actual experience found in the literature.

3.3.3. Decontamination

Primary circulating activity in the form of gaseous and particulate radionuclide species may be released from the PCRV into the containment during a depressurization or leakage event. Based on the magnitude of the release, an assessment is made to determine the combination of decay time and containment venting which would reduce the dose rate within the containment to a level that allows worker access for the purpose of decontamination. The time required for actual decontamination is estimated from actual cleanup operations that have taken place at national laboratory facilities and nuclear power plants. Adequate decontamination is deemed to have been achieved when the dose rates within the containment allow unrestricted worker access for periods of 40 or more hours per week.

3.3.4. Economic Model

An economic model to calculate the total loss to a utility resulting from HTGR plant accidents has been developed. This model identified the major cash flow elements which are affected by or are a direct result of an HTGR-SC/C accident. The model is based on the revenue requirement method (Ref. 3-6) which is the method generally used in the electric utility industry to assess economic consequences of alternate decisions involving power generation. The utility loss model is expressed in terms of financial equations which represent the cost and revenue sources during the time a damaged plant is off-line and being repaired. Each equation is comprised of several economic variables which portray utility economics based on Gas-Cooled Reactor Associates groundrules (Ref. 3-7), PUC response, and insurance recovery factors (Ref. 3-8).

The details of the model are provided in Appendix B of this report.

3.4. DATA BASE

An extensive data base is required both for frequency and consequence quantification. The data must be consistent with the methods and models used in the analysis.

Frequency modeling involves the quantification of initiating and event tree nodal events leading to failure or unavailability of various plant operating and protection systems. From the standpoint of frequency quantification, plant data is needed to describe such items as system function, redundancy, system interconnection and common mode failure. Hardware failure and repair data is also required, along with human operator response data. In general, the quantities of interest are the probability that the component or system cannot perform its intended function and the duration required to repair it. In addition, seismic analysis requires data on earthquake frequency and magnitude.

Consequence modelng involves quantification of transient, thermodynamic, and radiological responses. For consequence quantification, data on plant transient response, fission product behavior, and damage limits are needed. This requires extensive data on plant thermodynamic characteristics such as component flow capacity, flow resistance, heat capacity, material conductivity, along with data on fuel particle behavior, and fission product transport. For seismic analysis, data on component and structural fragility (susceptibility to damage) as well as structural coupling and vibration damping is needed.

Economic and financial data are needed to assess investment impact; for example data for component repair costs, equipment costs, replacement power costs, and decontamination costs.

3.5. UNCERTAINTY

The technique used to quantify the uncertainty in frequency probabilities is the same as that used in the reactor safety study (Ref. 3-9) and is known as the Monte Carlo method of error propagation. The method consists of statistically combining the uncertainty distributions of the input parameters associated with each event tree branch point using Monte Carlo simulation to arrive at an uncertainty distribution for the branch point probability. With the use of the methods introduced earlier, an algebraic expression is obtained relating the desired branch point probabilities to the input parameters, e.g., failure rates, repair times, common mode parameters, etc. The four factors leading to uncertainty in the input parameters, listed above, are considered by assigning an uncertainty distribution to each parameter. This information is then input to the computer code STADIC (Ref. 3-10), which uses Monte Carlo simulation of the distributions to generate an uncertainty distribution in the branch point probability as well as the mean and median estimates for the accident sequence frequencies.

Uncertainties in consequence predictions can also be calculated. The principal technique for accomplishing this is to describe with

uncertainty distributions, the parameters used in the economic model, including the estimates of the cleanup and repair costs and downtime resulting from component damage. The equations in the economic model and the uncertainty distributions of the parameters can be input to a Monte Carlo process which generates uncertainty distributions on the outputs, which are the consequences. These uncertainty distributions can then yield both the means and the median values of consequences.

3.6. REFERENCES

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4. INVESTMENT PROTECTION GOALS

The relatively high construction costs associated with nuclear heat sources for power generation has required users of this technology to commit substantial investments into single large facilities with the expectation that operation of such a facility over its design life will lead to a recovery of these costs. This concentration of investment has led, in recent years, to focus being placed on investment protection, that is, assurance that a single unexpected event does not damage the facility such that further recovery of capital investment is precluded. Beyond this, the higher initial costs, but lower fuel costs, make the economics of nuclear generated power, relative to its fossil fueled competition, a strong function of plant availability. Thus outages at a nuclear power station can be quite costly to the owner of such a facility.

GA and others have addressed these concerns by developing quantitative investment protection goals against which evolving plant designs may be measured as a part of judging their investment protection adequacy. The development of these goals has built upon the experience gained in formulating numerical safety goals for nuclear power plants and consequently these investment related goals are expressed and used in a manner similar to that of the more familiar safety goals.

Within the HTGR program investment protection goals have, as their focus, financial risk to the power plant owner. While other perspectives such as societal risk could be utilized, it is felt that owner or utility risk provides the most bounding limitation on plant design, particularly with regard to aversion to rare but costly events. While either a utility or a more global viewpoint leads to limitations on averaged annual costs, a global viewpoint fails to adequately identify the strong aversion to a rare but high cost event such as TMI. This

comes about because high consequence albeit rare events are more easily absorbed by society (or some larger population) than by the individual or company suffering the loss. This is, of course, the basis on which insurance companies operate and the rationale for government assistance during disasters. So long as the exposed population considered is large enough, losses can be annualized or averaged so that the costs of unlikely events is easily absorbed. However, it is an underlying philosophy of these investment goals that even if society or even the industry were able to accept large consequence accidents on a somewhat regular basis, such accidents are not acceptable to the utility owning a plant.

Two investment related goals are presented in this report and a preliminary word of explanation is provided here to obviate any confusion over references to these two goals. At the time this assessment was begun GA had proposed an Investment Risk Goal which was intended to limit dollar losses to the owner of an HTGR from unlikely or low probability accidents. The assessment was then performed in a manner that lent itself to ready comparison with this goal. More recently, the DOE sponsored HTGR Safety and Investment Protection Working Group has issued the program's investment protection goal. While this more recent goal has similar characteristics to the GA proposal, it has an expanded scope and is quantified in outage days rather than dollars lost. So while the assessment was not initially intended to be measured against this goal, it was deemed to be worthwhile to make a preliminary comparison of the already assessed plant performance with this newer investment protection goal.

4.1. FREQUENCY-CONSEQUENCE INVESTMENT RISK GOAL

The investment risk goal proposed by GA in February 1983 is shown in Fig. 4-1. It is aimed at limiting the allowed probability of occurrence of various events as a function of the financial consequence of those events. The goal implicitly differentiates between events that are expected to occur within the plant lifetime and those that are not.

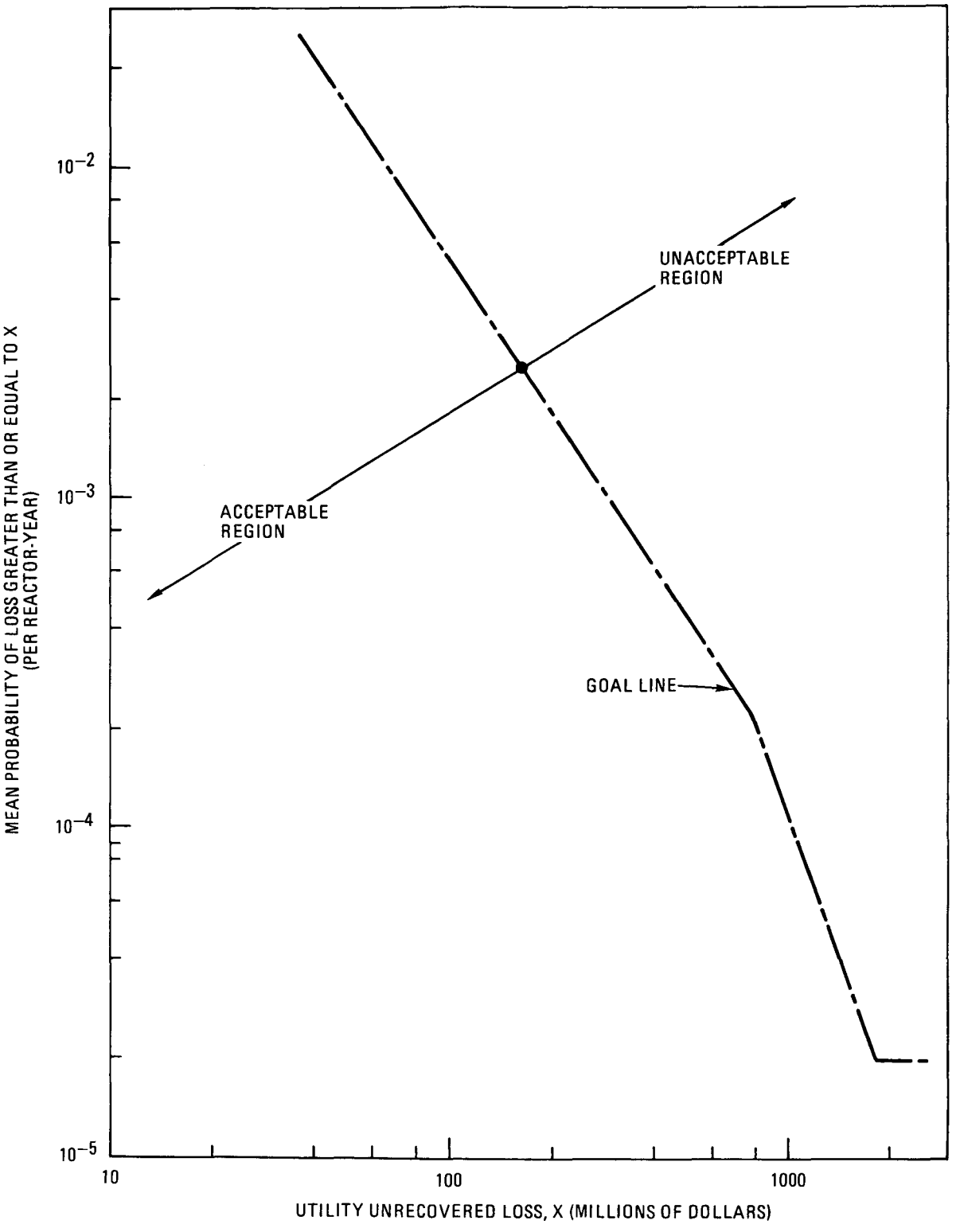

Fig. 4-1. Proposed investment risk goal line

The goal aims only to limit the frequency of financial loss due to unlikely events, that is those with a probability of occurrence of less than 0.025 per reactor year. More likely events, those expected to occur within the plant lifetime, are assumed to be limited by a separate availability goal.

The specifics of ownership and risk sharing cannot be known in quantifying what is an acceptable financial risk to a utility. However, several broad criteria do exist which can give some idea of what constitutes acceptable investment risk. These criteria include utility equity, cash flow, insurance and profit expectations. Using these criteria the investment risk goal delineating acceptable and unacceptable risk was proposed.

Referring to Fig. 4-1, the top of the goal line, at a probability of 0.025 per reactor year, is what has historically been known as the transition point between purely availability considerations, aversion to longer outages, and investment risk. Above this frequency, availability considerations are governing. The transition point, itself, is set such that the outage contribution from rare events should not have a substantial adverse impact on the total average plant availability. Below that frequency, losses due to accidents (accounting for insurance and rate relief) are allowed to increase somewhat as the probability of such accidents decrease. This characteristic is selected because the relatively moderate losses involved happen only occasionally in the industry, can be dealt with within the context of normal utility cash flow, and can be written off over a few years. However, the accidents represented at the bottom of the goal line involve such large and immediate losses, on the order of total equity, that they are beyond the means of a utility to absorb within its normal cash flow and the utility's viability as an economic entity is brought into question. For accidents of such severity, the goal provides good assurance that they will never occur to any of an assumed population of reactors.

4.2. RISK - CONSEQUENCE INVESTMENT PROTECTION GOAL

More recently the HTGR Safety and Investment Protection Working Group has adopted a goal aimed at protecting the investor in an HTGR (Ref. 4-1). This goal is:

> "The plant will be designed and operated in a manner which provides the following successive layers of investment protection:
>
> 1. Limit forced outages to a fraction of the overall plant availability goal.
>
> 2. Provide increased protection against long outages over a wide spectrum of events.
>
> 3. Limit the cost of decontamination and decommissioning to an insurable amount should the plant be damaged beyond repair."

The three major points of this goal are further quantified in Ref. 4-1 as follows:

1. Limit forced outages means limit the average equivalent unplanned outage rate to less than 10% (36.5 days/year).

2. Provide increased protection means limiting the risks of long outages to a level comparable with equivalent sized coal plants. This implies that outages of six months or greater should not represent more than 10% of the total average equivalent unavailability (3.65 days/year) and precludes events with a frequency of greater than 10^{-5} per plant year from resulting in a plant loss.

3. An insurable amount implies that should an event resulting in plant loss occur, the costs of decontamination and decommissioning would be less than currently available insurance ceilings (i.e., <$1 billion).

This goal, like the GA proposal, also is intended to limit dollar losses to the utility owning an HTGR. However, recognizing that losses are domianted by plant outage time, the goal's authors have elected to quantify the goal in terms of outage time rather than dollars. A graphical interpretation of this goal has been made by GA and is seen in Fig. 4-2. In order to accurately depict the availability criterion a novel plot of risk versus consequence was introduced rather than the more conventional frequency versus consequence "risk plot." Diagonal lines of constant frequency have been superimposed over the plot to assist the reader in relating this figure to the more familiar frequency-consequence plots.

The goal adopted by the Working Group and plotted as described has two distinct regions. In the upper left portion of the figure the horizontal line represents a desired limit on the average equivalent unscheduled outage days per year, in this case 36.5 days per year. Note that neither the criterion nor the target line discriminate over the length of the outages causing this amount of outage, so long as these outages are not "too long." For example, seven 1-day outages are as acceptable as a single week-long outage. However, the totaled average from all causes must not exceed 36.5 days per year.

On the right-hand side of the figure, the sloping target line represents criteria for aversion to long outages. This portion of the curve can be thought of as being the rough equivalent of the GA Investment Risk Goal discussed in Section 4.1. The basis of this aversion to long outages is twofold. First, recent actions by public utility commissions have shown a trend to penalize a utility if a nuclear unit does not maintain better than a 50% availability factor over any year. Of source, a long outage (>six months) would preclude such an availability.

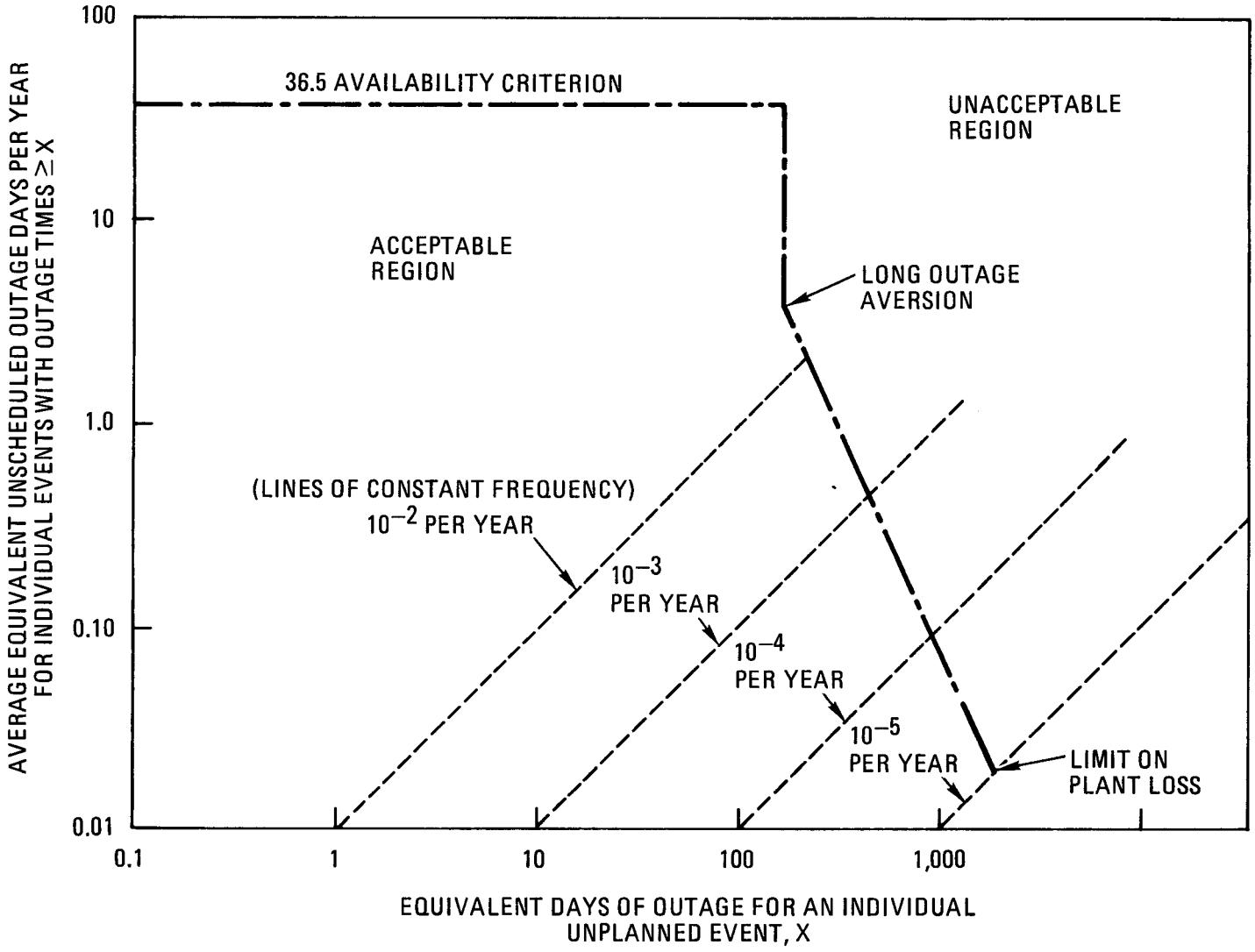

Fig. 4-2. Graphical interpretation of investment protection goal from the DOE HTGR Safety and Investment Protection working group

Furthermore, a severe accident with its accompanying long downtime can seriously threaten the financial viability of a plant owner as discussed in Section 4.1. Note that irreparable damage to the NSSS has been equated with a five-year outage (Ref. 4-2) and is precluded at frequencies greater than 10^{-5} per year.

The final criterion incorporated in the new goal regarding the adequacy of insurance for decontamination and decommission, is not portrayed by Fig. 4-2 and would be handled separately.

4.3. REFERENCES

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5. PLANT DESCRIPTION

The investment risk assessment was based upon the Baseline 0 design of the 2240 MW(t) steam cycle/cogeneration HTGR plant including more recent modifications to the design where pertinent. This section highlights the major aspects of this design with emphasis on those features of particular relevance to the risk assessment. The reader interested in detailed descriptions of particular systems is referred to the applicable design documents such as Refs. 5-1 and 5-2.

5.1. NUCLEAR STEAM SUPPLY AND BALANCE OF PLANT DESCRIPTION

The 2240 MW(t) HTGR-SC/C plant is designed to produce high temperature, high pressure steam for either electric power, process plant usage or a variable mix of both.

The reactor containment building (RCB) houses the prestressed concrete reactor vessel (PCRV) and other nuclear steam supply system (NSSS) components and is designed to limit radioactivity release during normal and accident conditions. The RCB is a reinforced-concrete structure with a design pressure of 60 psig.

The major components of the nuclear steam supply system NSSS are contained within the prestressed concrete reactor vessel pictured in Fig. 5-1. The core itself is an approximately cylindrical assembly consisting of hexagonally shaped graphite fuel elements stacked in 541 eight block high columns. The fuel elements are of two types: standard elements and control elements. Both contain fuel which is inserted into small vertical holes drilled parallel to the vertical axis, along with a large number of small diameter holes which provide a coolant flow path through the core. In addition, the control elements contain three larger diameter channels to accommodate control rods and the reserve

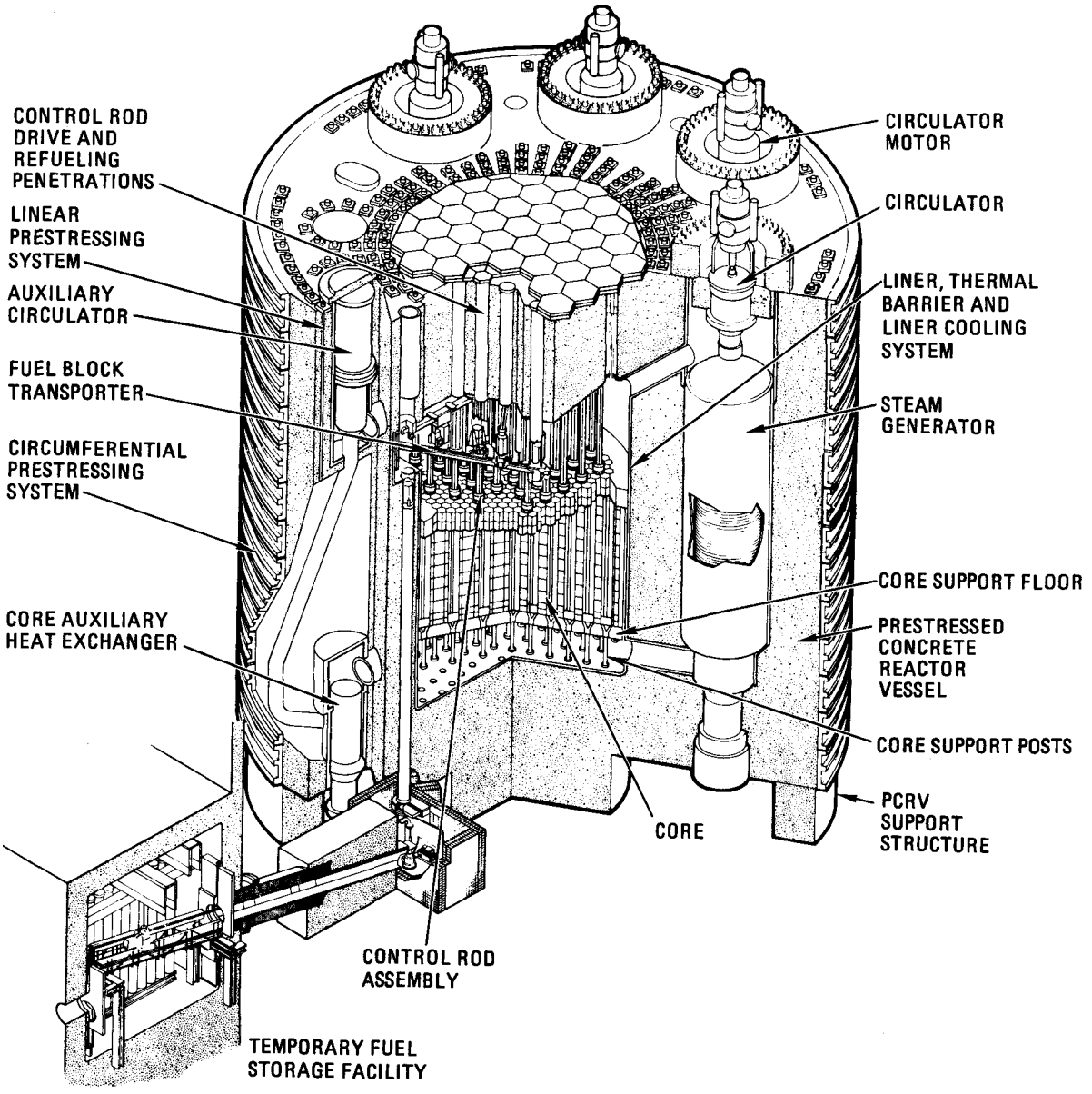

Fig. 5-1. 2240 MW(t) HTGR-SC/C

shutdown system. These graphite fuel elements are capable of surviving temperatures far in excess of their normal operating temperatures and coupled with their large heat capacity show no appreciable deterioration after extended interruptions in cooling. Located in near proximity to the core within the core cavity are a number of metallic components including the control rod cladding, rod support cables, plenum elements and orifice flow control valves, the in-vessel refueling structure, and the thermal barrier cover plates.

Within the PCRV are also the two independent and self-redundant HTGR cooling systems. These are the normally used Heat Transport System (HTS) and its backup the Auxiliary Heat Removal System (AHRS).

The HTS consists of four replicate loops, each containing its own steam generator, helium circulator and loop isolation valve. During plant operations and normal shutdown conditions helium, heated in the nuclear core, is circulated through any number of these loops where the heat is rejected to the steam generators. Feedwater and steam outlet lines for the four steam generators are headered in common within the balance of plant (BOP). Power for the four main circulators is provided by the two nonessential 13.8 kV buses in the plant. Cooling water for all four circulators is provided by the nonessential Reactor Plant Cooling Water System (RPCWS).

The other system provided for HTGR core cooling, the AHRS, consists of three redundant, two replicate and one diverse, cooling loops. The AHRS is designed to provide shutdown core cooling whenever heat rejection through the main loops, the HTS, is not possible. Each of the three AHRS loops is capable of removing nuclear decay heat under pressurized conditions following reactor shutdown. Although two loops are required under licensing conservations for cooldown when the reactor is depressurized, adequate cooling may actually be supplied by only one loop under most depressurized conditions.

Internal to the PCRV each loop is provided with a helium circulator, an auxiliary heat exchanger, and a loop isolation valve. Circulators and heat exchangers between the three loops are identical. Two of the loop isolation valves are flapper type check valves preventing reverse flow through a stopped circulator, the third and diverse valve has an automatically actuated power operated valve.

External to the PCRV each AHRS loop is provided with an auxiliary cooling water subsystem (ACWS) designed to remove heat from the auxiliary heat exchanger and reject it to the atmosphere. Two of the ACWS circulating water loops are replicate containing identical pumps and valves as shown in Fig. 5-2. The third ACWS loop is required to be diverse (Ref. 5-3). Each of the ACWS loops reject heat to the atmosphere through an air blast heat exchanger located in one of three ultimate heat sink structures located about the reactor containment building.

Each of the AHRS loops receives its power from one of the three class 1E 4.16 kV buses respectively. Motor winding and oil cooling water for each of the auxiliary circulators can be provided by either redundant train of the essential Reactor Plant Cooling Water System (RPCWS) via three intermediate and replicate circulating water loops of the Auxiliary Motor Cooling Subsystem. Furthermore, the capability to provide this heat removal task with the nonessential reactor plant cooling water system is also provided.

Maintaining PCRV concrete temperatures within design limits is accomplished by the Liner Cooling System (LCS) in conjunction with the insulation of the thermal barriers. The LCS consists of two redundant circulating water loops operating in parallel. Either loop is capable of removing the design heat load from the PCRV concrete during both normal and design transient conditions. Water flow for the two LCS loops is provided by the two essential trains of the reactor plant cooling water system.

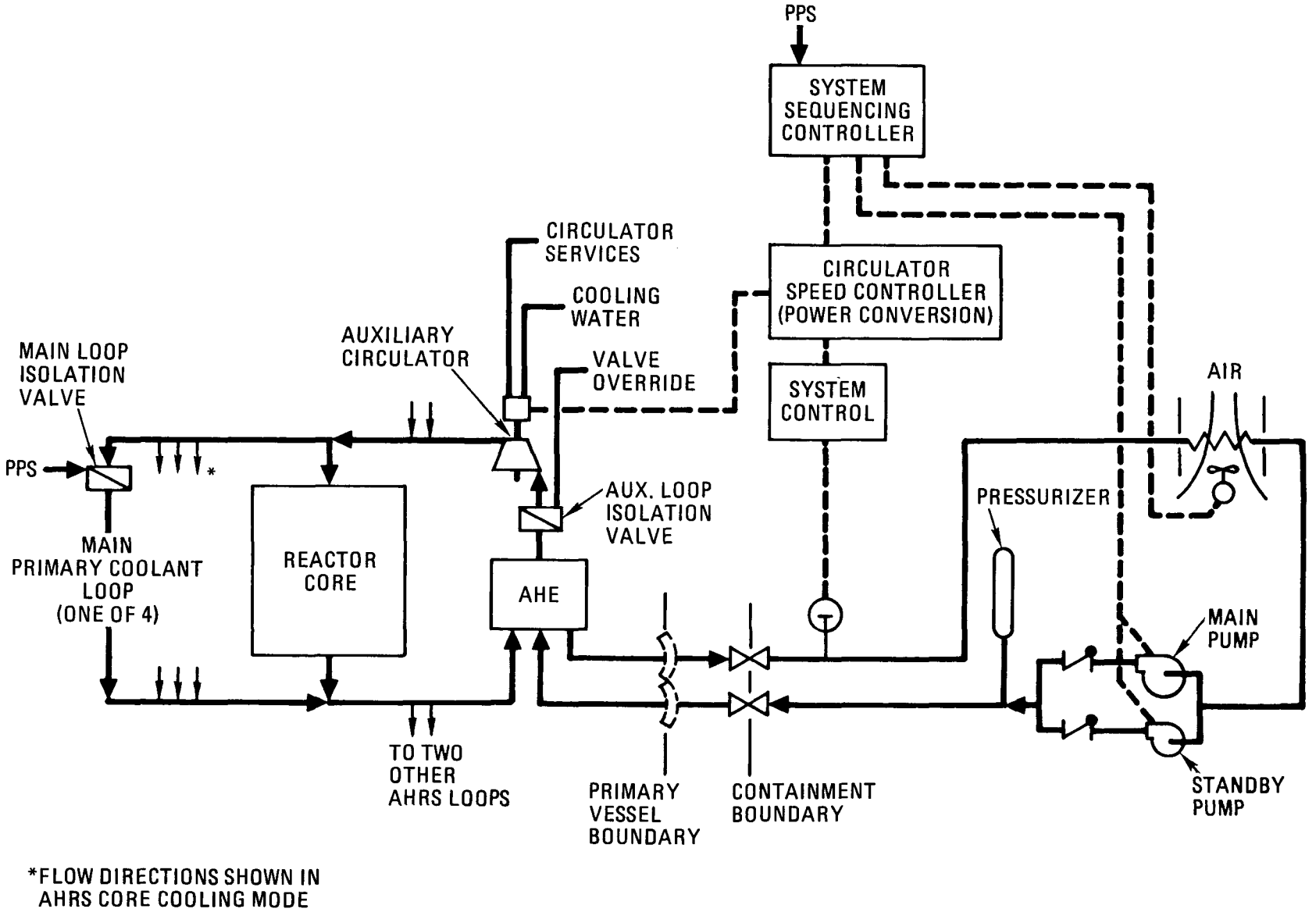

Fig. 5-2. AHRS functional schematic

The essential RPCWS trains reject heat to the Nuclear Service Water System NSWS. The preferred source of water for the NSWS is the normal service water system (SWS) which, by taking a suction on the discharge of the circulating water pumps and discharging to the circulating water return header, uses the main cooling towers as an ultimate heat sink. Should the SWS be unavailable, two standby NSWS pumps are provided to maintain water circulation through the NSWS. In using the NSWS pumps, water is circulated to and from the ultimate heat sink basins. Should this not suffice, operator action can direct firewater to the nuclear service water system with fire pump discharge and suction directed to the main cooling tower basins.

The BOP is illustrated schematically in Fig. 5-3. Steam from the four steam generators is joined in a common header where it is directed to the high pressure turbine. High pressure turbine exhaust is, in turn, directed to the process facility and one, two, or three of the IP, LP turbine generator sets, the number of sets dependent upon process steam demand. Three 50% condensate pumps and five 25% feedwater pumps return the condensed steam to the steam generators.

Turbine overspeed protection consists of two diverse protection systems, one with redundancy. First, a speed governor closes all throttle valves on moderate overspeed. At higher overspeed (but still under the damage threshold), emergency tripping occurs. This is accomplished by an emergency governor acting to close all throttle and stop valves. A diverse overspeed trip mechanism (one mechanical and one electrical) insures this action.

Electric power for equipment within the BOP is supplied by one of four nonclass 1E buses mentioned below. Circulating cooling water for the turbine generator sets, condensate pumps, boiler feed pumps, and the station air compressor is provided by the Turbine Building Closed Cooling Water System (TBCCWS). The TBCCWS rejects heat to the SWS.

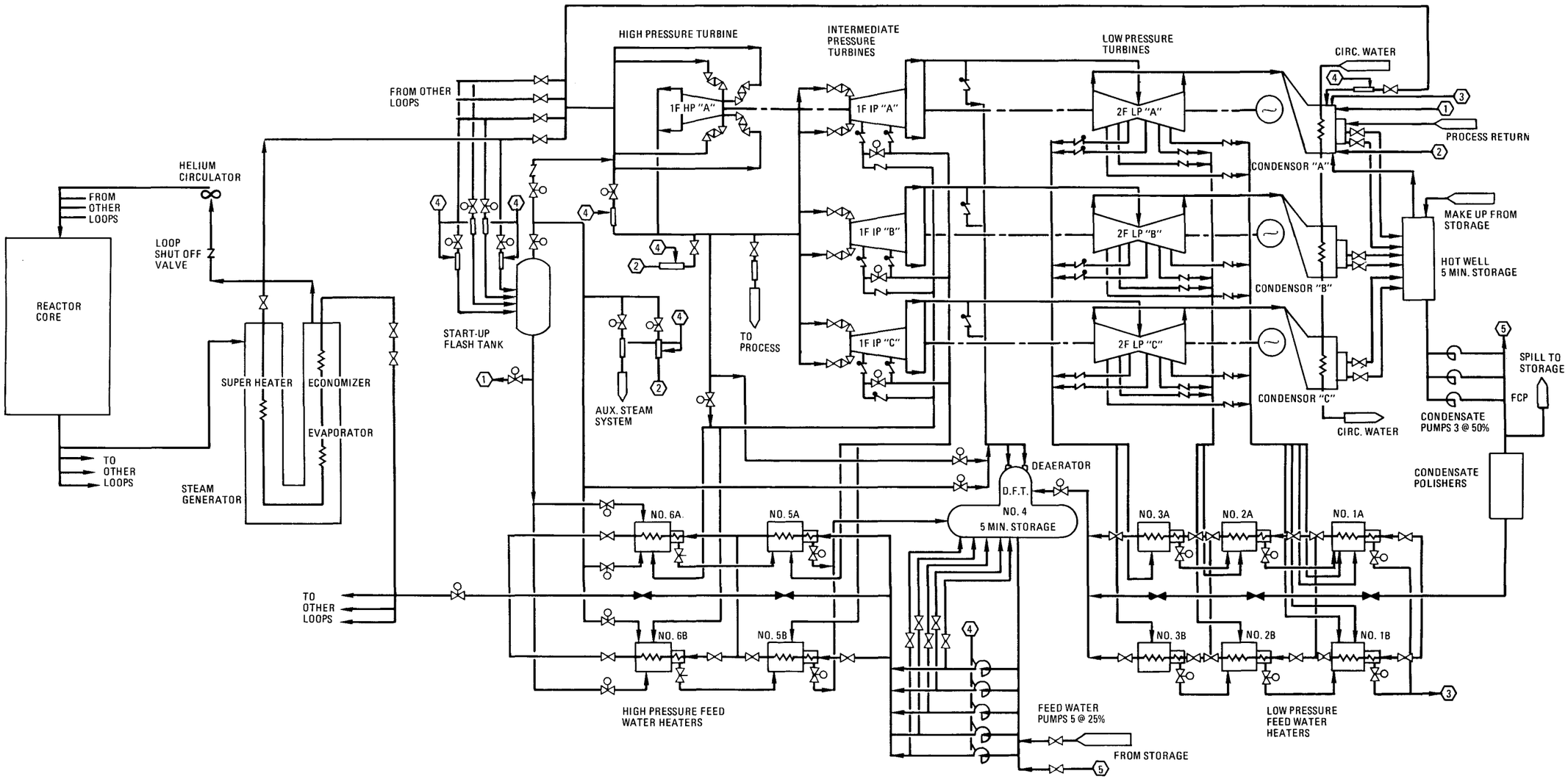

Fig. 5-3. Power conversion flow diagram of 2240 MW(t) SC/C-HTGR

Plant electric powered auxiliaries, plant control, protection, surveillance systems and the engineered safety features equipment is powered from four Nonclass 1E buses and three Class 1E buses. Preferred power for all of the above buses is the turbine generator output. In fact, on loss of off-site power the HTGR is designed to remain "on-line" supplying all of its in-house electric loads. Alternatively, power can be supplied from the grid through the generator step-up transformer or through two reserve auxiliary transformers. Finally, each of the three Class 1E buses has its own associated diesel generator set should the other power sources be unavailable.

5.2. ECONOMIC DESCRIPTION OF PLANT

The cost to a utility to recover the use of the plant after it has been damaged will include direct repair costs (less insurance coverage) and replacement power costs that depend on such things as the location of the plant, the rate structure at that site, the practices of the local utility rate controllers, and the local costs of alternative fuels.

For the purposes of this analysis, parameters have been used that are representative for a single 2240 MW(t) HTGR located on a hypothetical average site, Middletown, USA. This plant produces 470 MW(e) of electrical power and 1411 MW(t) of process steam, with a capacity factor of 65%. The utility has been assumed to carry one billion dollars of property insurance, and replacement power insurance that pays 90% of the replacement power costs during the seventh through eighteenth months of an outage and half that for the next 12 months. Other details of the economic model are described in Appendix B. Loss calculations are 2005 projections in 1983 dollars levelized over 30 years consistent with 1983 GCRA Groundrules in Ref. 5-4.

5.3. REFERENCES

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6. TRANSIENT FREQUENCY ASSESSMENT

The value of probabilistic risk assessment methods stems in large part from not only determining the consequences of various plant transients but quantifying the likelihood of such a consequence occurring. The following sections discuss how the probability of occurrence for the various transients considered in this assessment were quantified.

Section 6.1 briefly addresses the HTGR reliability data base used for the transient frequency assessment. Section 6.2 discusses the choice of transient initiating events contributing to the overall investment risk of the 2240 MW(t) HTGR-SC/C plant. Section 6.3 traces the event tree development of each transient initiating event to an ultimate transient outcome. These outcomes are identified by consequence categories ranging in severity from no impact on plant operations to total loss of plant investment. Finally Section 6.4 discusses the uncertainty analysis performed on the frequency assessment.

6.1. DATA BASE

The reliability data for the frequency assessment described here has been extracted from a broad range of sources. These sources include gas-cooled reactor data (Ref. 6-1), U.S. nuclear data (Ref. 6-2), previous PRA studies (Refs. 6-3, 6-4, and 6-5) and special summarized data (Ref. 6-6). Synthesized data has also been used, particularly for estimating common mode failures of pumps (Ref. 6-7), valves (Ref. 6-8), and control systems (Ref. 6-9).

The Common Mode Failure (CMF) data base for this, as well as previous GA studies, was based upon two parametric analytic models: the β-factor model (Ref. 6-4) and a modified Binomial Failure Rate Model (Ref. 6-10) with lethal shock. These models are important because CMFs

are found to dominate the high consequence risk resulting from failure of the redundant HTGR systems. Multiple examples of the use of the CMF data base are given in Section 6.3.

Uncertainty estimates from the data base were factored into all frequency calculations. Uncertainties at the fault tree level were incorporated into the event trees to generate median branch frequency estimates as well as upper and lower bounds for the total frequency.

6.2. INITIATING EVENTS

The choice of transient initiating events used in the 2240 MW(t) SC/C investment risk assessment was based on three sources. The first of these, previous investment risk assessments was used to identify initiating events which have previously been shown to lead to transients which are dominant in defining the financial risk associated with owning and operating an HTGR. The second source was a recent study (Ref. 6-11) done on the investment risk stemming from graphite block failures. Finally consideration was given to identifying other transients which could result in extended downtimes with probabilities high enough to affect the bounding risk envelope already established by the first two sources.

Interruptions of core cooling and primary coolant leaks have historically been the dominant contributors to investment risk and therefore have been included in this study. From the recent safety study (Ref. 6-12) three initiating events were identified as having the potential to lead to an interruption in core cooling at frequencies of interest. These three transient initiators are: a loss of main loop cooling such that auxiliary cooling will eventually be required (LMLC), a loss of off-site power (LOSP), and a loss of service water (LSWS). Primary coolant leaks are considered without regard to precursors as an initiating event.

Steam generator leaks while not historically a major investment risk concern, are dominant in safety studies (Ref. 6-12). Because of this and because of the relative difficulty in replacing a steam generator if an unexpected transient should render it unusable, steam generator leaks have been included as an initiating event.

A loss of liner cooling has, for some time, been recognized as a potentially severe investment threat should the loss be sustained long enough to lead to concrete damage. As the active portion of the liner cooling system, a loss of essential reactor plant cooling water (LRPCW) has also been included as a transient initiating event.

In addition, the results of a recent assessment (Ref. 6-11) of the investment risk hazard due to cracking in the graphite blocks of the HTGR core have been included here.

Finally, scoping analysis has been performed on three additional initiating events identified as potentially significant risk contributors. These include: (1) a spectrum of seismic events such as operational basis (OBE) and safe shutdown earthquakes (SSE), (2) turbogenerator failure, and last, (3) inadvertent actuation of reserve shutdown system (RSS). These final analyses are not detailed and are intended only as first order estimates of event frequencies and consequences.

The hazard to investment due to all external events has not been included. For instance, major in-plant fires, while not believed to contribute to safety risk (Ref. 6-13), cannot be entirely ruled out as contributing to investment risk. However, based on this previous work it is considered unlikely that fires are important in defining the risk envelope.

6.3. EVENT TREES

In this section the calculations leading to assessed accident frequencies are discussed. Each subsection focuses on one of the transient

initiating events identified in Section 6.2 and the subsequent chain of events, if any, leading to a condition of plant damage and/or outage. Those portions of the assessment based heavily on previous work are treated in less detail than those areas that are new to this study. For further detail on these former works, the reader is referred to the referenced studies.

6.3.1. Loss of Main Loop Cooling

As a transient initiating event, a loss of main loop cooling is the collection of occurrences within the plant, excluding loss of off-site power or service water, which ultimately require core cooling to be provided by the auxiliary heat removal system. An LMLC can be caused by both failures of the heat transport system to transport core heat to the steam generators as well as failures of the BOP to reject the heat deposited in the steam generators to the environment. The basis of interrupted core cooling model is the LMLC analysis of Ref. 6-12.

The sequence of events following an LMLC is presented in the LMLC event tree of Fig. 6-1 along with the assessment results including nodal probabilities, branch frequencies and damage categories of the various branches.

Event 1 of the event tree in Fig. 6-1 is the transient initiating event, a loss of main loop cooling. The fault tree analysis used in quantifying the frequency of this event is illustrated in Fig. 6-2. The dominant failure modes leading to the assessed LMLC frequency of 0.25 per reactor year occur in the power conversion system (BOP). In particular, improper response to turbine trip and deaerator level control failures dominate the BOP failures. Table A-1 in Appendix A lists the data base for assessing the LMLC frequency.

Even if an LMLC occurs it may be possible to continue heat removal on the main loops for a limited period of time with "once-through" cooling of the steam generators. In this mode of operation the deaerator

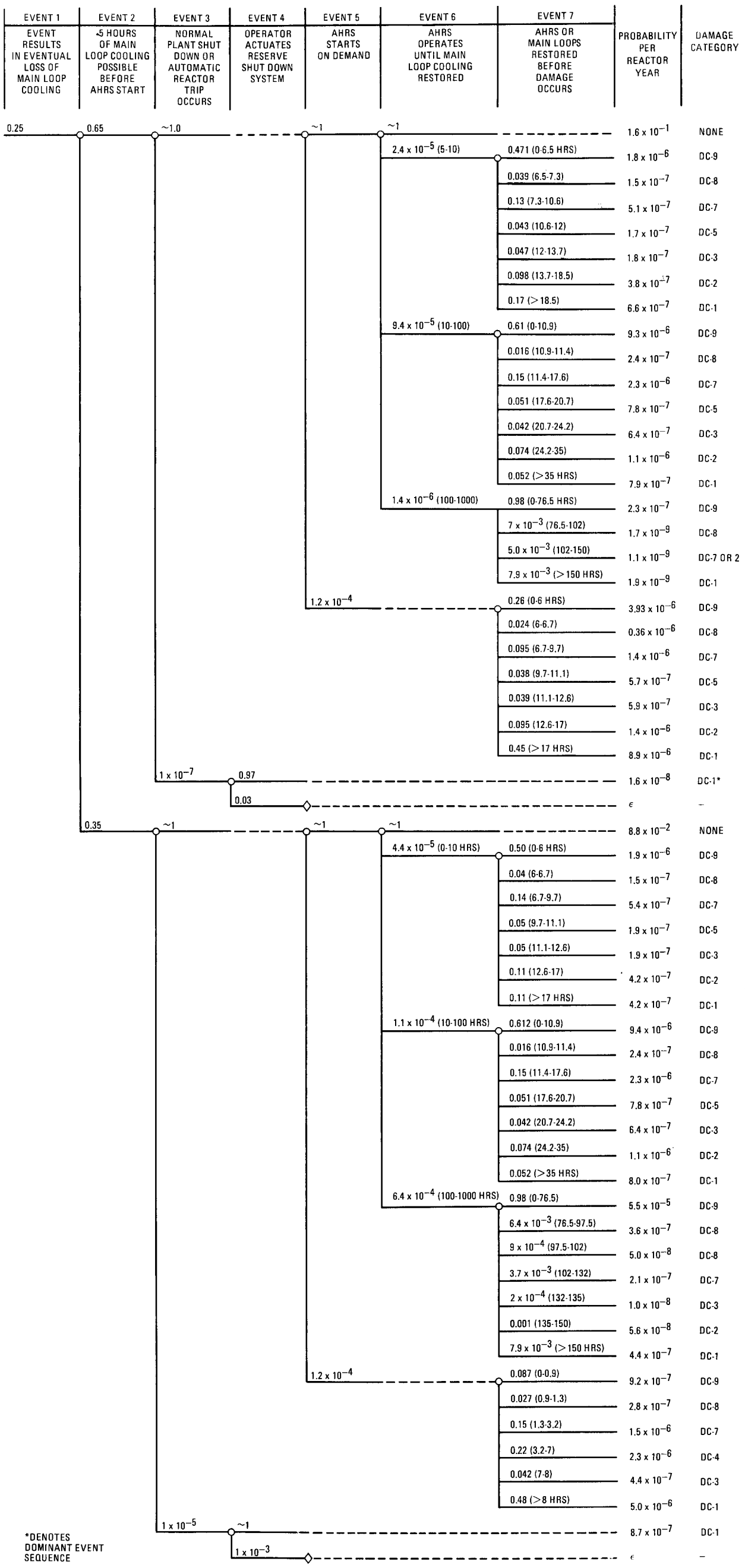

Fig. 6-1. Event tree for loss of main loop cooling

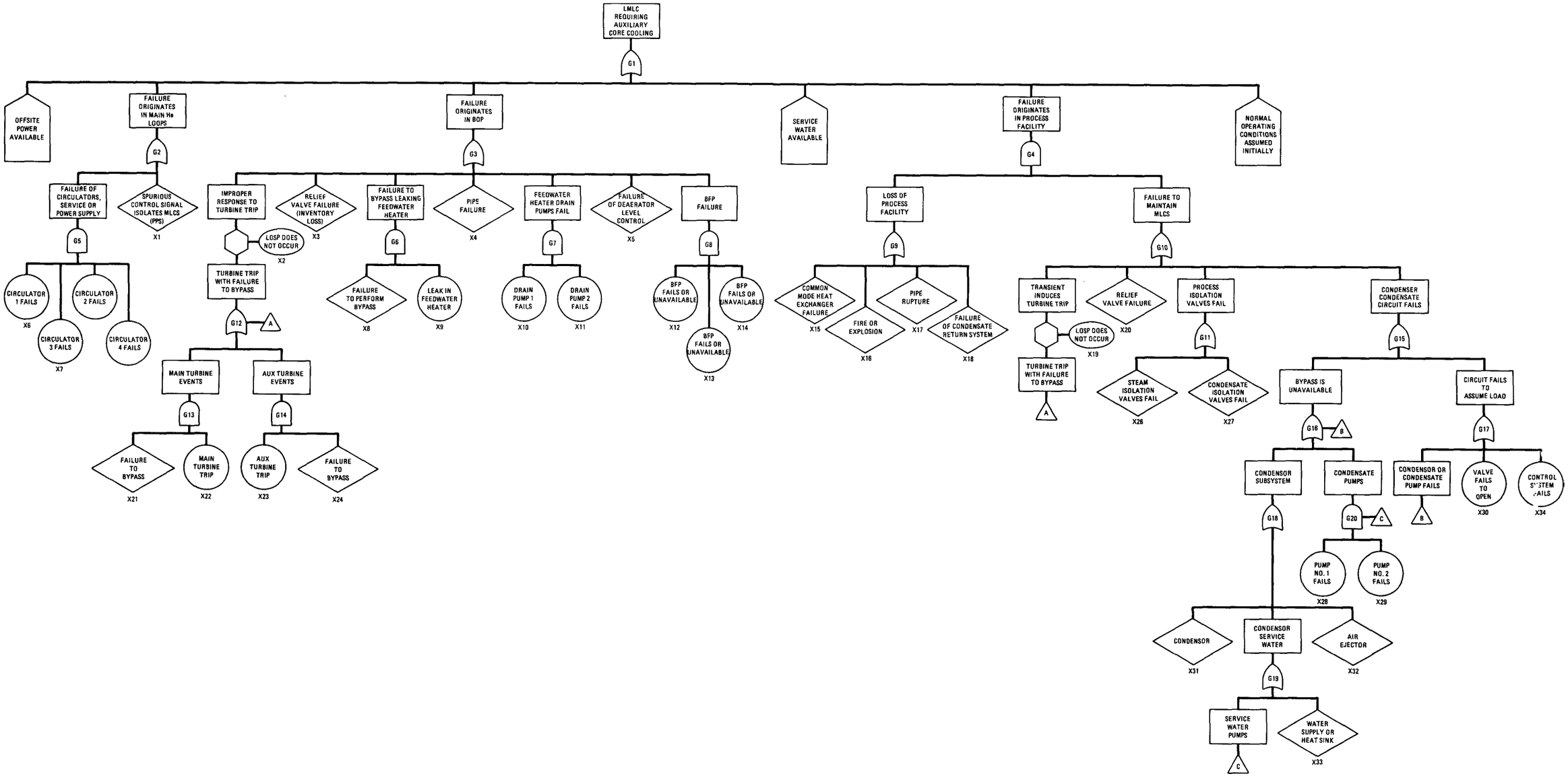

Fig. 6-2. Fault tree for frequency of loss of main loop cooling

and condensate water inventories are pumped through the steam generator and exhausted to atmosphere. Event 2 of Fig. 6-1 considers this possibility. The probability of success in providing this once-through cooling is the probability that the cause of the LMLC was a failure other than a failure in the NSSS cooling loop or one of the BOP components required to pump the water inventory through the steam generator. Those failures identified in the LMLC fault tree that would prevent successful once-through cooling are, referring to Fig. 6-2; X4, G2, G8, G9, G11.

Events 3 and 4 consider the possibility of failing to shutdown the reactor core. With the very high reliability of the HTGR's two diverse and redundant shutdown systems, the probability of failing to insert control rods or activate the reserve shutdown system is well below any frequency meaningful in an investment risk assessment.

Event 5 considers startup of the Auxiliary Heat Removal System. Following the LMLC initiating event the AHRS must be started if core cooling is to be maintained. If the LMLC is such that once-through cooling is precluded, the demand for AHRS startup is immediate. In the event that once-through cooling of the steam generators is possible, the demand for AHRS startup is delayed. However, after 5 hours of cooling in this manner, it is conservatively estimated that the condensate inventory is depleted and AHRS startup is required.

Whether startup is immediate or delayed, the mechanisms available to prevent startup are the same. Figure 6-3 shows these mechanisms, both for the AHRS failure to start and failure to run, in a fault tree. The data used to quantify the failure of the three redundant AHRS loops is listed in Table A-2.

Event 6 considers whether the AHRS continues to run until the main loop cooling system is repaired and capable of resuming cooling. Of course, if the AHRS failed to start in event 5, then clearly it cannot continue to run and this is shown in the event tree by the dotted line.

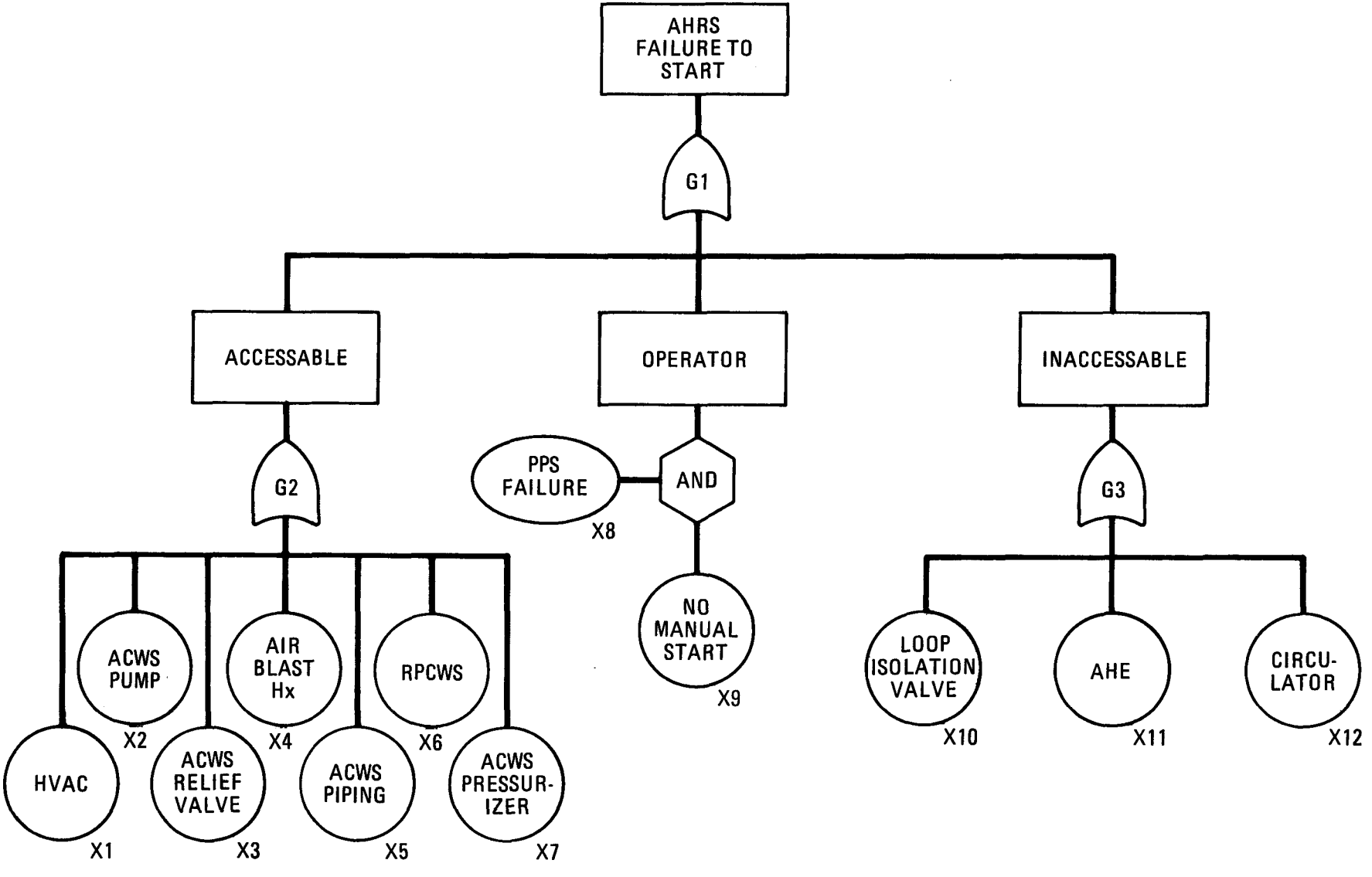

Fig. 6-3. AHRS failure to start fault tree

In the more likely case where the CACS starts, the probability of it continuing to run until main loop cooling is restored is based both on the reliability of the AHRS and an effective repair rate for the main loops. The integral solution model used to determine this probability over some time interval is described later in this section.

Note that the solution for event 6 is dependent upon the exogenous conditions of the particular branch being dealt with. For instance, if once-through cooling of the steam generator in event 2 has succeeded, then the cause of the LMLC cannot be a failure within the PCRV. Therefore, the failed component should be accessible and the probability that main loop cooling is repaired is dependent only on the time available and the various component repair rates. Conversely, in other event sequences, the solution must consider the probability that the failure occurred within the PCRV, is inaccessible and therefore is irreparable over the time intervals being considered.

Finally, if both the main loop and AHRS cooling are interrupted, the consequences will depend upon the time required to restore cooling. Depending upon the length of the cooling outage various degrees of core heating result leading to ever increasing damage to components located within the PCRV. Beyond a certain time temperatures reach a point that restoring cooling is precluded. In Section 7 various damage categories, corresponding to the time intervals the core is left uncooled, are discussed. The probability of restoring cooling during these intervals is considered in event 7.

6.3.2. Loss of Normal Electric Power

The active components required for core cooling by the main loops are all powered from the nonsafety class, non-vital N 13.8 or 4.16 kV buses. Power for these buses can be supplied from the turbine generator output or from the off-site power grid via the 500 kV switchyard or as a backup, the 138 kV switchyard. Upon a failure of off-site power, the

HTGR turbines are designed to remain on-line, uncoupling themselves from the grid and continuing to provide power to in-house loads.

The transient initiating event considered here is an improper response of the power conversion system following a loss of off-site power such that the electrical non-vital N buses loose power. Such an event immediately renders main loop cooling inoperative and begins the event sequence depicted in Fig. 6-4.

Reference 6-5 identifies the dominant mechanism for this occurrence to be a loss of off-site power followed by turbine trip. The assessed frequency is 0.034 per reactor year.

Given a loss of power to the normal buses, subsequent actions are partly dependent upon the timing of restoration of off-site power. The probabilities of power recovery in various time intervals (Ref. 6-4) are shown as the nodal probabilities of event 2 in Fig. 6-4.

Events 3 and 4 consider the shutdown of the nuclear core by either control rod insertion, event 3, or the reserve shutdown system, event 4. However, as in the LMLC event tree, the probability of these redundant systems failing is so low as to not be of particular interest to investment risk.

The loss of power to all non-vital buses and the resultant loss of main loop cooling places an immediate demand upon the AHRS to start. Event 5 considers the probability that the AHRS starts on demand.

The treatment of AHRS reliability is similar to that discussed in Section 6.3.1, the difference being that both preferred power and alternate power (138 kV switchyard) is not available to the Channel 1E 4.16 kV buses. Therefore, before the AHRS starting sequence can begin, the 330 kW diesels supplying emergency power to the 1E buses must be brought on-line. The probability of at least one AHRS loop not being started under these circumstances is compared with the probability of

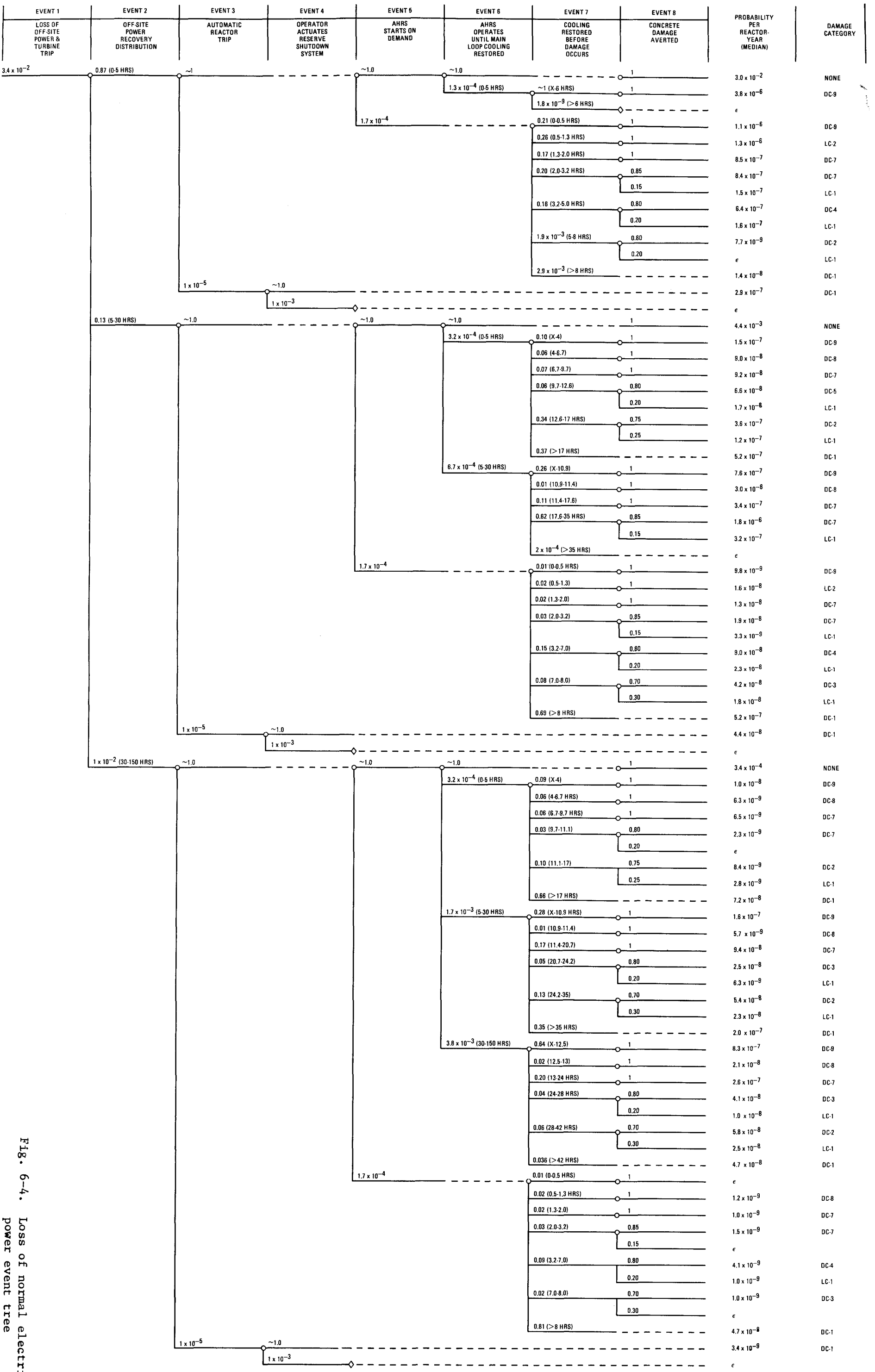

Fig. 6-4. Loss of normal electric power event tree

AHRS failure given power available in Fig. 6-5. The probability of all three diesels failing to start is assessed at 7×10^{-5} per demand.

As in the LMLC tree, event 6 considers whether the AHRS, given that it started, continues to operate until main loop cooling is restored. Differences between the two calculations center around the differences in initiating events. In evaluating restoration of main loop cooling, it is assumed that no in-plant equipment repair is required. Rather, restoration of main loop cooling is dependent on off-site power restoration. The reliability of the running AHRS is similar to that portrayed in Fig. 6-3 except that now the running diesels provide an additional failure mode. Failure rates for running diesels are presented in Table A-3.

If the AHRS fails to run until off-site power is restored, the final issue, considered in event 7, is how much, if any, damage occurs before one of the loops in either of the two cooling systems (main loops or AHRS) can be returned to service. As discussed in Section 7, the degree of damage incurred increases with the duration of the interruption in cooling. Therefore, the distribution of cooling restoration times seen in event 7 correspond to various categories of damage severity.

6.3.3. Loss of Service Water

Failures in support systems which provide essential service to multiple components has been recognized as an important intersystem dependency failure in otherwise redundant cooling systems. The loss of normal electrical power is recognized as one such failure. Loss of service water is another that requires individual treatment.

As a transient initiating event, a loss of service water is defined to be a loss of the Service Water System (SWS), the non-essential Reactor Plant Cooling Water System (NRPCWS) or the Turbine Building Closed Cooling system (TBCCWS). A loss of any one of these systems renders

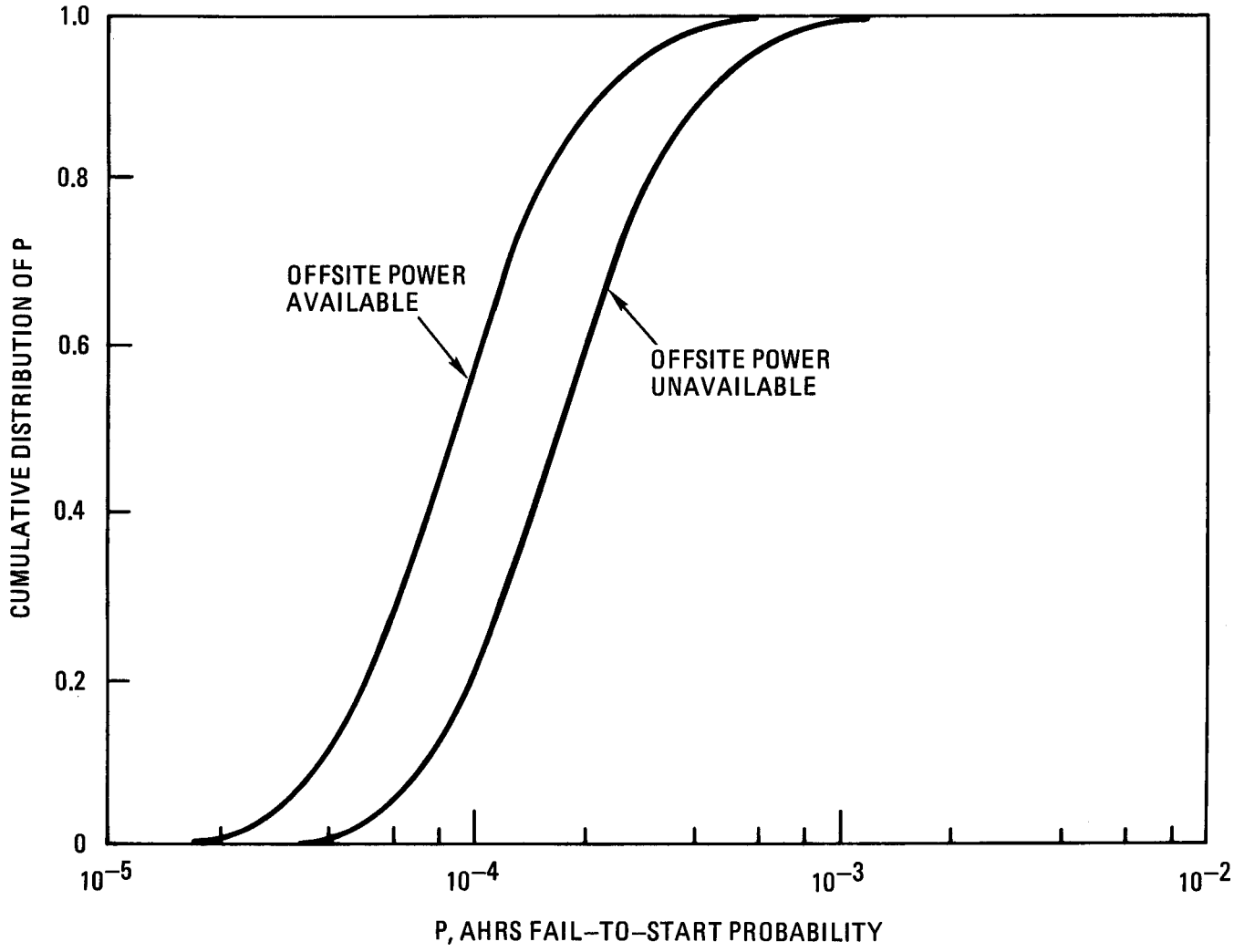

Fig. 6-5. Cumulative distributions for AHRS fail-to-start probabilities, with and without preferred power available

main loop cooling inoperable and begins the sequence of events depicted in Fig. 6-6.

These various supporting cooling water systems and their relationship to one another are illustrated schematically in Fig. 6-7 and a fault tree illustrating their failure modes is given in Fig. 6-8. Notice that the fault tree differentiates between failures in the SWS or the Circulating Water System (CWS) and failures in NRPCWS or the TBCCWS. While all these failures result in a loss of main loop cooling, only the former group (SWS and CWS) require startup of the Nuclear Service Water System in event 2.

Failures requiring NSWS startup, G2 in Fig. 6-8, and failures not requiring NSWS startup, G3, are comparable in their contribution to the initiating event frequency. G2 is dominated by obstructed suction to the circulating water system or the failure of two out of three service water pumps. G3 is dominated by common mode failures of the redundant pumps in the NRPCWS or TBCCWS or fatal failures in the temperature control system. The data base for quantifying the fault tree of Fig. 6-8 is given in Table A-4.

Given that the transient initiating event, event 1 of Fig. 6-8, has occurred, Event 2 considers whether or not NSWS startup is required and if so whether or not the system successfully starts.

From the previous discussion of the event 1 fault tree, the probability that NSWS is required is just the probability that the initial failure occurred in the SWS or the CWS which provides suction to the service water pumps. Therefore, the probability that NSWS startup is required given event 1 is the ratio of G2 to G1.

To determine the probability of the NSWS failing to start consider the tie between the SWS and NSWS shown in Fig. 6-9. Not only must the NSWS pumps start, but suction and discharge valves must operate correctly. These failure mechanisms are outlined in the NSWS fault tree of

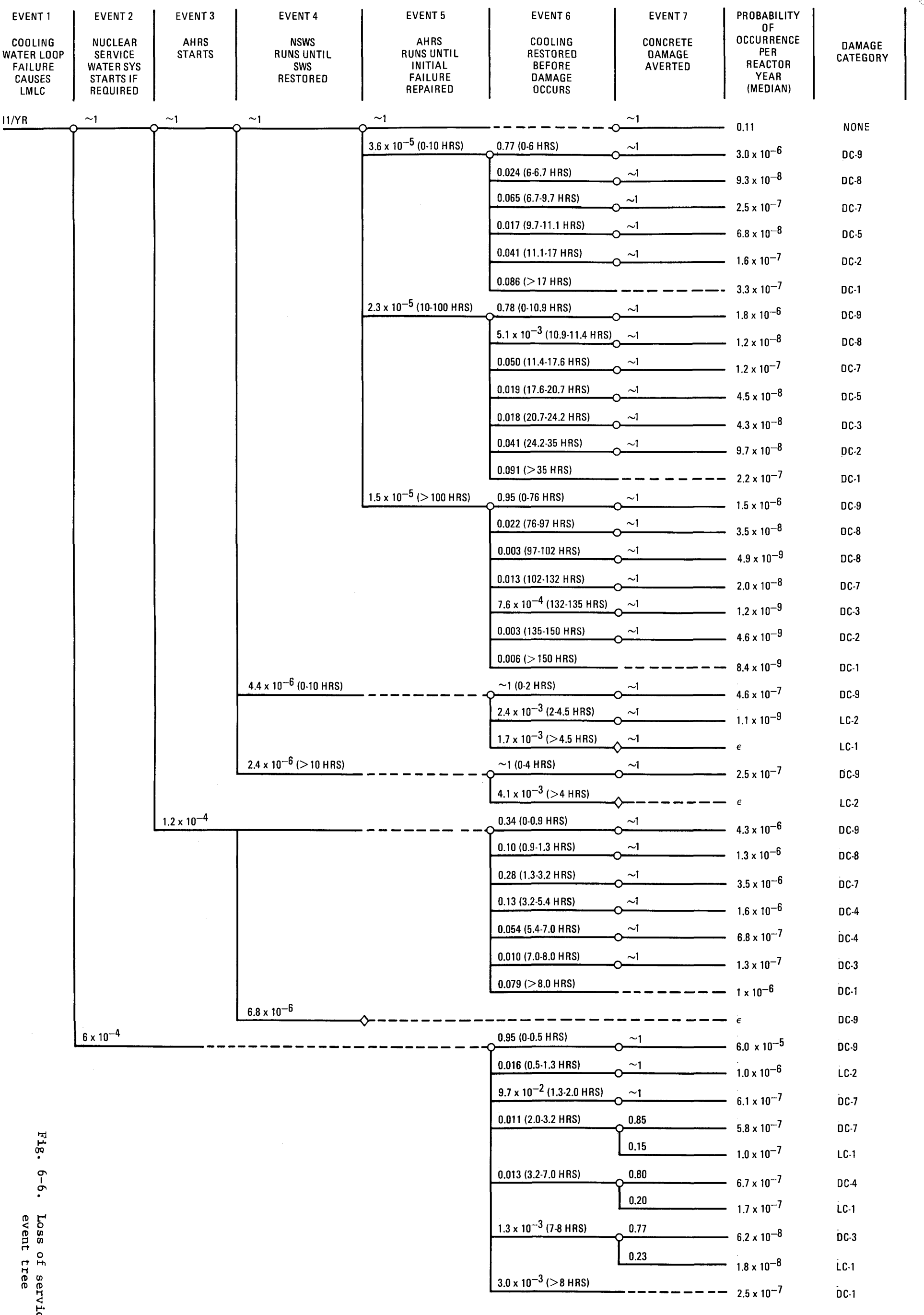

Fig. 6-6. Loss of service water event tree

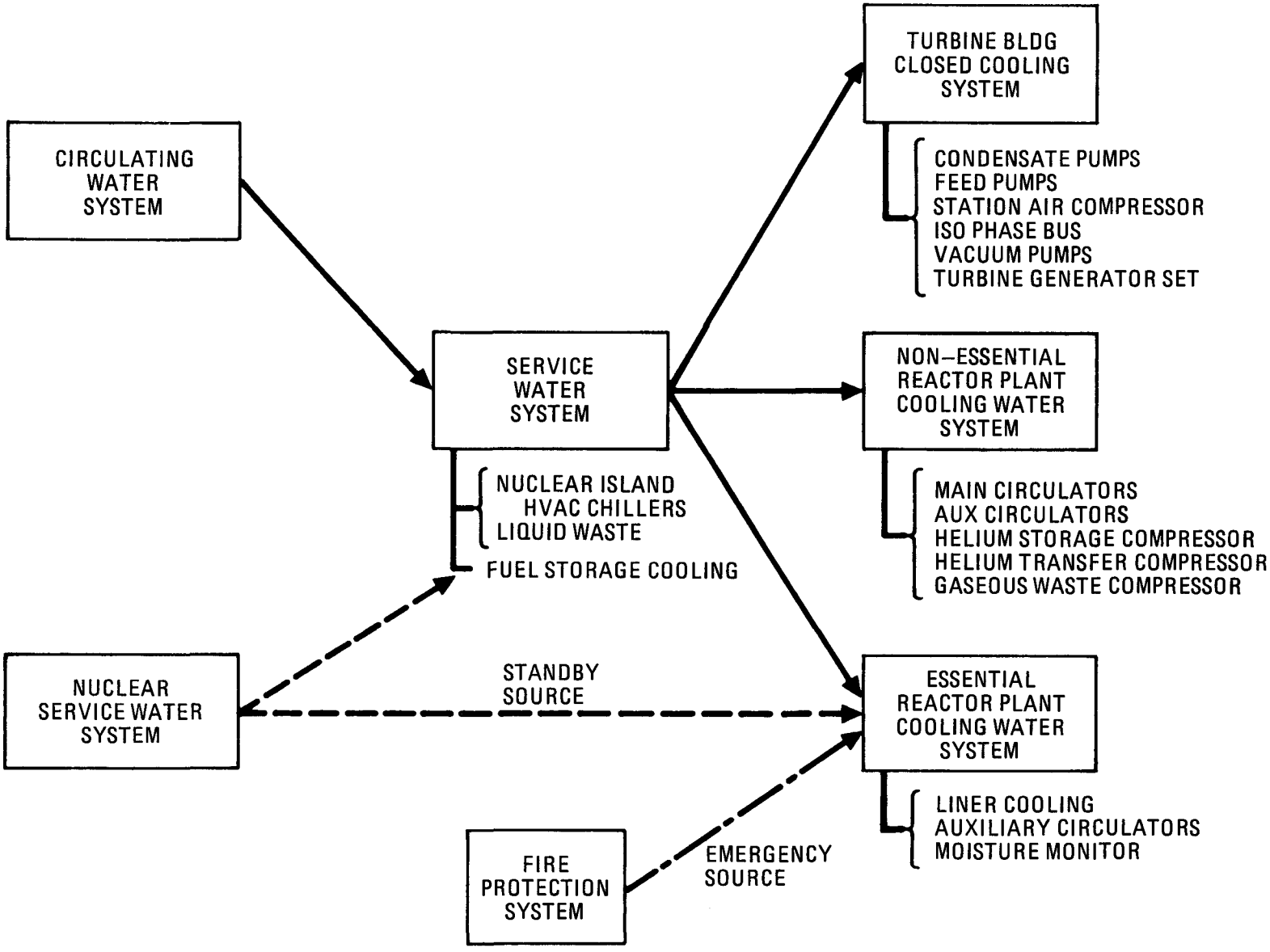

Fig. 6-7. Relationships and heat loads on various supporting cooling water systems

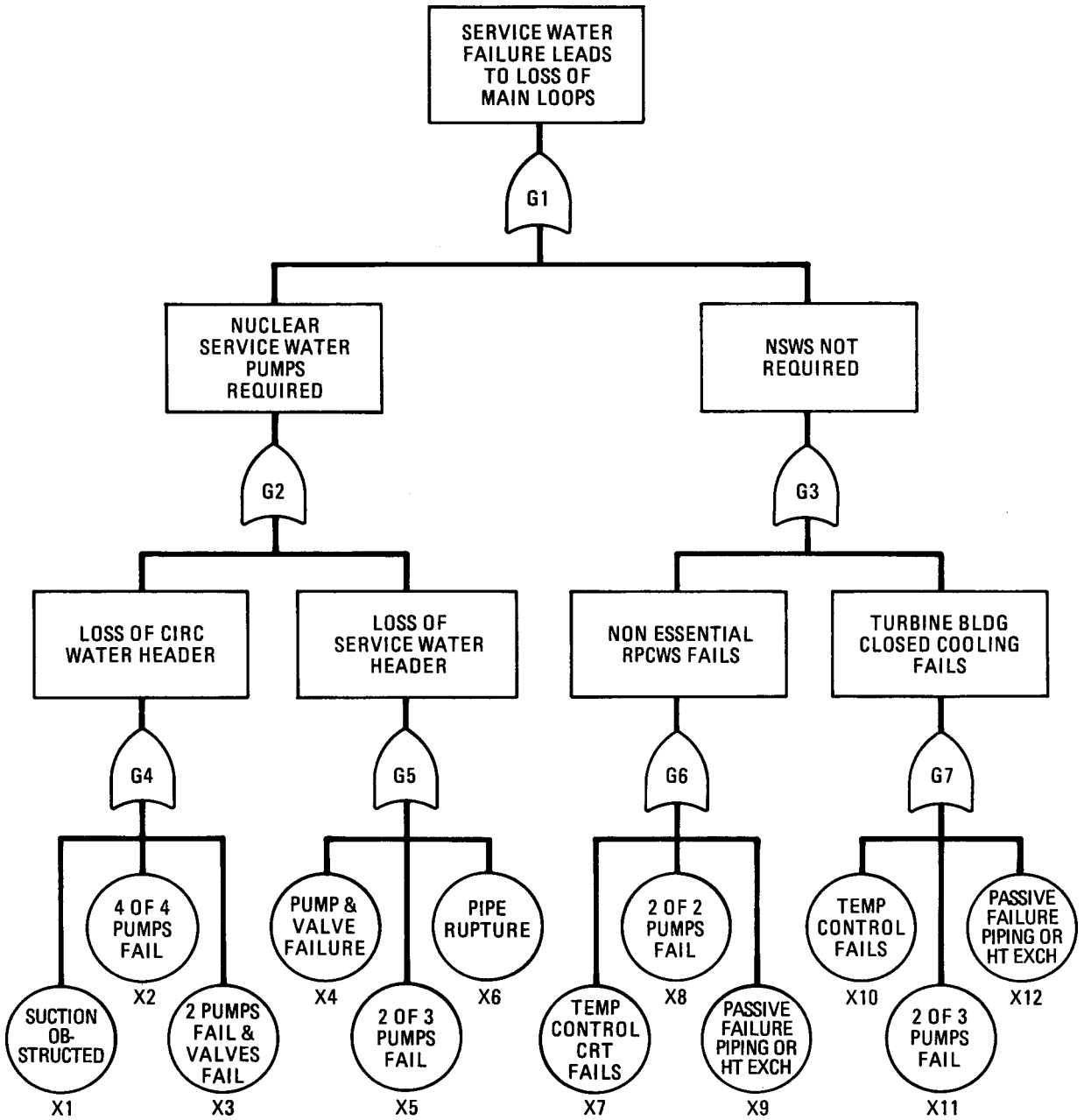

Fig. 6-8. Loss of service water initiating event fault tree

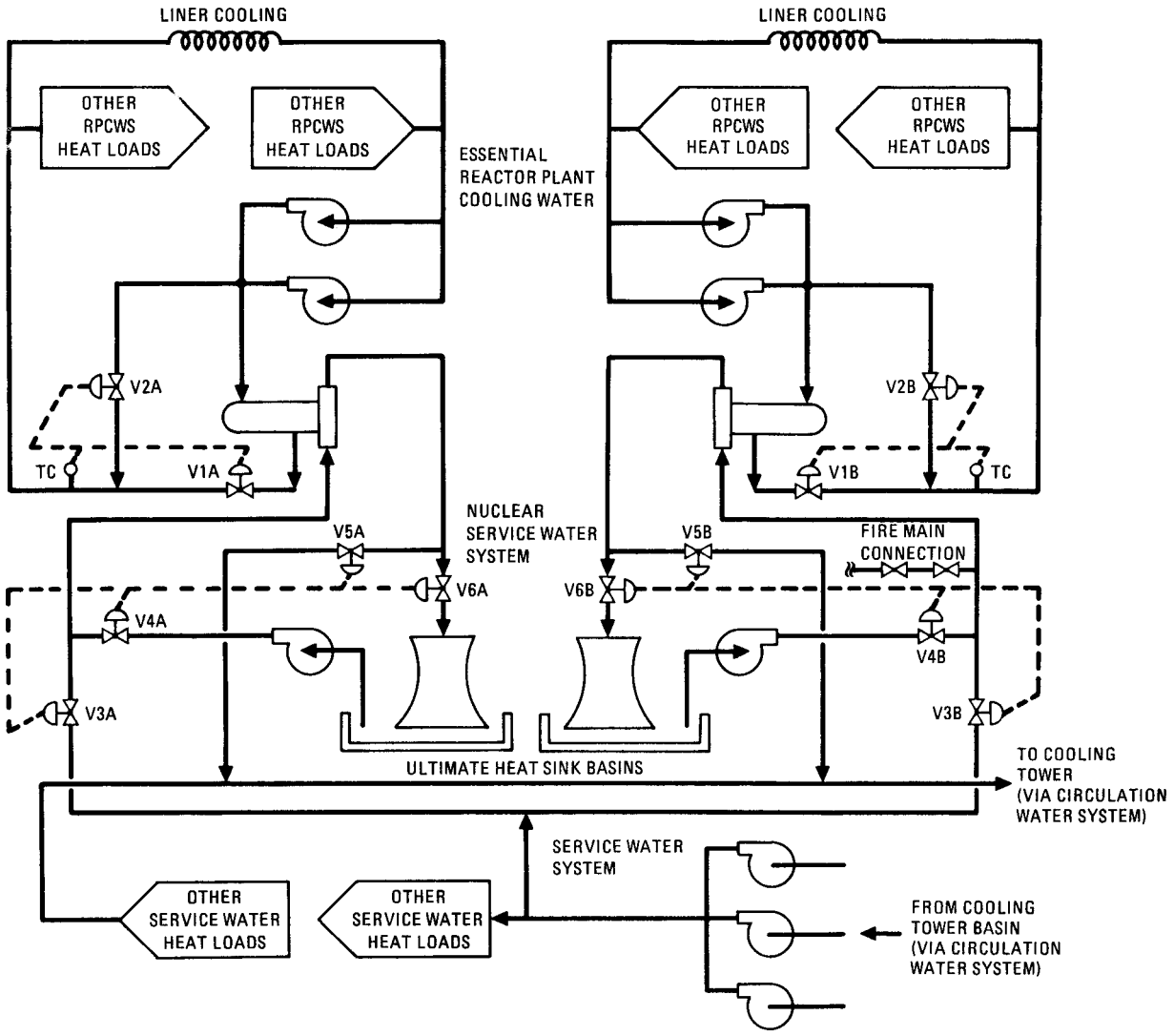

Fig. 6-9. SWS and NSWS cooling of the essential RPCWS

Fig. 6-10 and its data base is listed in Table A-5. However, in addition to these failure mechanisms which are independent of the initiating event failure, Ref. 6-14 gives a common mode factor between the SWS and NSWS pumps of 5×10^{-4}.

The total probability, then, of the NSWS failing to respond as required is the summation of the independent and common mode contributions.

Regardless of the outcome of event 2, startup of the AHRS is required to maintain core cooling. Event 3 considers AHRS startup.

If nuclear service water startup is not required or is required and has occurred successfully, startup of the AHRS is identical to the case treated previously following LMLC (see Section 6.3.1).

If, however, nuclear service water is required but does not successfully start, startup of the AHRS is precluded. This is due to the auxiliary circulator motor's need for cooling. This cooling can be provided by either the NRPCWS or the essential RPCWS. However, the exogenous conditions implied by a failure of event 2 include a loss of both normal and nuclear service water, the heat sinks for these systems.

Event 4 considers whether the NSWS continues to run until normal service water is restored. Of course, if the NSWS failed to start as required, it cannot continue to run. In addition, if NSWS startup was never required, then the success of event 4 is assured.

In the non-trivial case where the NSWS successfully started and is running, the probability of a NSWS failure occurring before the normal service water system is restored during the time interval t_1 to t_2 is determined by considering the reliability of the operating NSWS and the repair rates of the various components in the normal service water system.

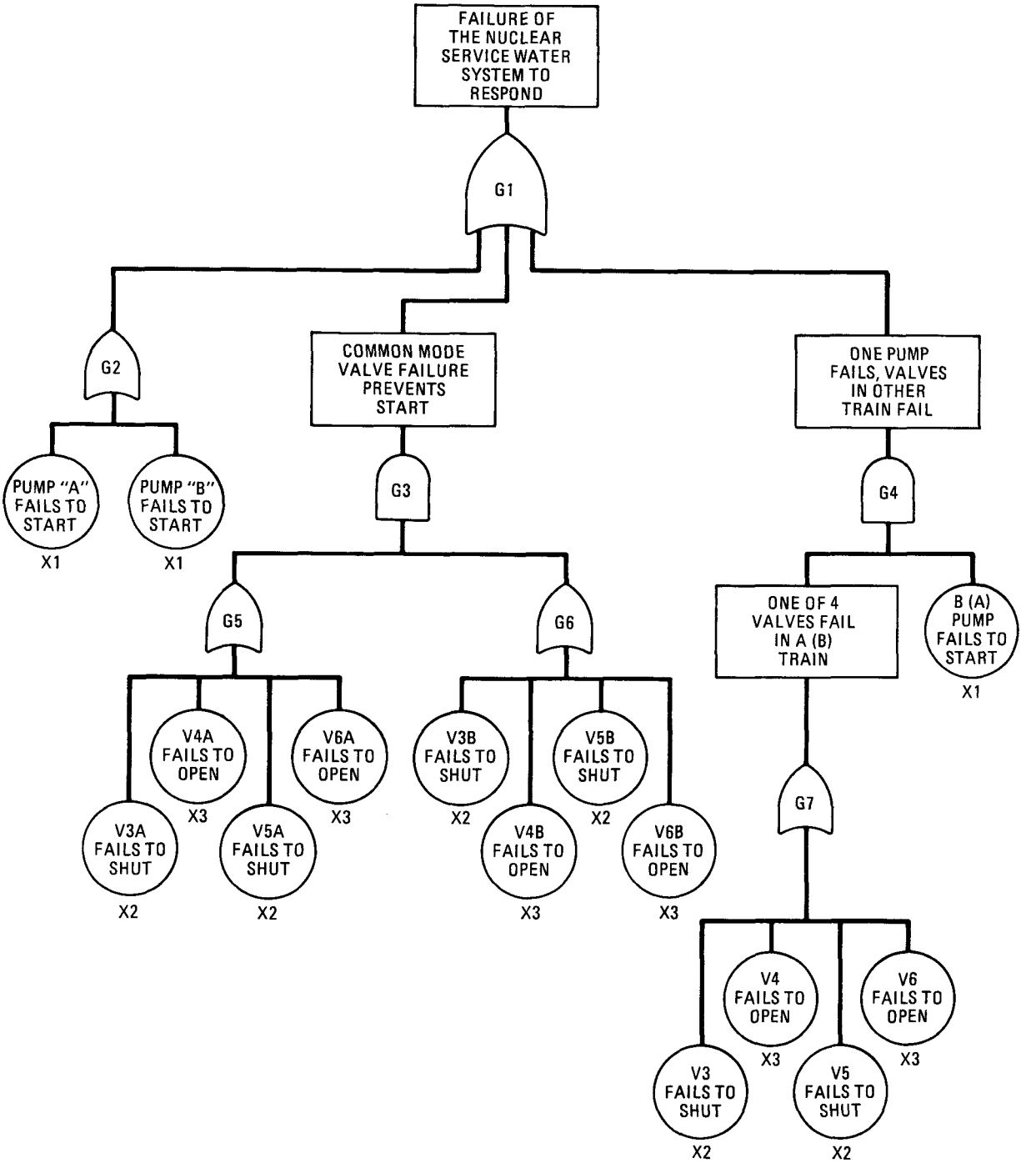

Fig. 6-10. Nuclear service water system fails to start fault tree

The data base for quantifying the repair model is contained in the relevant fault tree data base Tables A-4 and A-5.

If the NSWS was required but fails to operate until normal service water is restored, core cooling is interrupted since AHRS operation cannot continue without the RPCWS heat sink. However, even if it continues, the AHRS may suffer a failure internal to itself prior to restoration of main loop cooling. Event 5 considers these possibilities, that is, whether the AHRS continues to run until the main loops are restored.

Because AHRS component failures have been described in the similar event of the LMLC event tree, they will not be repeated here. However, it is pointed out that whereas the main loop restoration model was based on repairing the failed component(s) identified in the main loop fault tree (Fig. 6-2) in this case restoring the main loops hinges on restoring a failed water cooling system identified in the loss of service water fault tree, Fig. 6-8. Of course, if the AHRS failed to start, it cannot run at all.

If the auxiliary cooling and nuclear service water continue to run as required until the transient initiating fault is rectified, the transient is terminated, the system has operated as designed, and no damage is predicted. If, however, this does not occur, the potential damage to the plant and therefore the financial loss is based on the time to restore cooling. The restoration of cooling is considered under four sets of exogenous conditions in event 6. Also, the general methodology used in modeling repair throughout this assessment is described in greater detail as it relates to this event.

Consider first the delayed loss of auxiliary core cooling. In this case the AHRS has started and run for some period of time. However, at some time, x, before repairs have restored main loop cooling, auxiliary cooling fails. The question addressed is what is the probability of restoring main or auxiliary cooling before some other time, τ.

Repairs of main loop and auxiliary cooling are independent and are assumed to go on simultaneously. Therefore, the probability of success in event 6 given a failure of event 5, $Pr(6|5)$, is given by,

$$Pr(6|\bar{5}) = 1 - Pr(\text{MLC Not Restored}|\bar{5})\ Pr(\text{AHRS Not Restored}) \quad ,$$

and

$$Pr(\text{MLC Restored } \bar{5}) = \frac{Pr(\text{MLC Restored} \cap \bar{5})}{Pr(\bar{5})} \quad .$$

The probability of the AHRS not running until main loops are restored, Pr(5), has already been discussed. The intersection of main loop restoration and 5 is given by

$$Pr(\text{MLC Restored} \cap \bar{5}) = \sum_{i=1}^{N} p_i \int_{t_1}^{t_2} \int_{x}^{x+\tau} P_m(x)\ R_i(x)\ \frac{\partial R_i(t-x)}{\partial t}\ dtdx \quad ,$$

where t_1 to t_2 is the interval over which the AHRS fails,

$$P_m(x) = e^{-\lambda x} \quad ,$$

is the probability of the AHRS successfully operating until some time x, and

$$R_i(x) = e^{-\mu_i x} \quad ,$$

Represents repair of the ith component in one of the cooling water loops which is preventing main loop cooling, and,

$$p_i \frac{\lambda_i}{\sum_{j=1}^{N} \lambda_j} ,$$

is the probability of the ith component failing given that some failure has occurred.

For AHRS repair in time τ,

$$\Pr(\text{AHRS Not Restored}) = 1 - \sum_{i=1}^{N} p_i \, e^{-\mu_i \tau} .$$

The various component repair times and p_i's used in event 6 are given in Table A-6.

The second set of exogenous conditions considered in event 6 is the delayed loss of nuclear service water. In this case the NSWS system has started and run for some time. However, the system fails at some time, x, before normal service water is restored. Of course, without normal or nuclear service water available, core cooling is precluded. In this case event 6 considers the probability that service water is restored by some later time τ.

The solution is analogous to the previous case except as noted. Since the NSWS was required, the initiating event failure must have been in the service water header. Therefore, the repair model only considers repair of these components. Furthermore, since the NSWS started successfully, its primary failure mode is limited to failures in its two redundant pumps. Finally, a third repair avenue is available and that is through directing firewater to the NSWS supply header. The

probability of the operator failing to make this alignment is assessed at 9×10^{-3} (Ref. 6-15).

The third case considered is failure of the AHRS to start on demand. The repair model has been discussed in Section 6.3.1 and is not repeated here. Note, however, that restoration of the main loops involves repairing components in one of the cooling water loops.

The final set of exogenous conditions treated in event 6 is repair following failure of the nuclear service water system to start. Restoring main loop cooling is based on restoring the service water header, G2 of Fig. 6-8. Repair and startup of the NSWS allows starting of the AHRS. Directing firewater to the NSWS supply header is a third option. However, if the NSWS failed to start because of failures in valve V3 or V6 of Fig. 6-9, firewater cannot be directed to the RPCWS heat exchanger until the valve is repaired. The conditional probability that values V3 or V6 have failed, given that the NSWS failed to start is 0.06. Therefore, in this case the probability of failing to successfully hook up firewater to the NSWS header is,

$$\Pr(\text{FW Hookup Fails}) = 9 \times 10^{-3} \times 0.94 + 0.06\, e^{-\mu_{valve}\tau} \quad .$$

When water flow is lost in the NSWS supply header, the essential RPCWS has no heat sink. Among other effects already discussed, failure renders liner cooling inoperative. In conjunction with the loss of core cooling, these failures allow the concrete temperature to rise. The temperature rise if allowed to continue can lead to exceeding concrete temperature limits and concrete damage. Figure 6-11 shows the assumed probability of concrete damage as a function of temperature. Using this figure and knowing the maximum concrete temperature attained for various lengths of cooling failures, event 7 shows the probability of concrete damage.

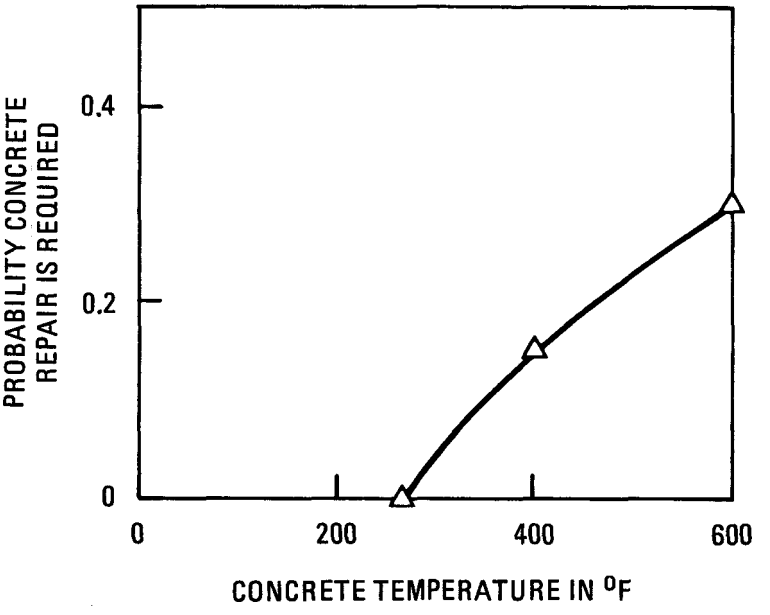

Fig. 6-11. Probably of concrete repair as a function of concrete temperature

6.3.4. Loss of Essential RPCWS

As pointed out in Section 6.3.3 a loss of essential reactor plant cooling water renders the liner cooling system inoperative but does not affect continued main loop cooling. It also precludes use of the auxiliary circulator motor cooling loop, however, backup cooling to the auxiliary circulator motor is provided by nonessential reactor plant cooling water. The loss of liner cooling, though, if not mitigated by corrective action risks degradation of the PCRV concrete as temperatures in the concrete equalize with the adjacent primary coolant system. In the previous section consideration was given to losses of the essential Reactor Plant Cooling Water system (RPCWS) due to loss of heat rejection through the normal or backup Nuclear Service Water System. The transient initiating event here considers failure of both the A and B trains of the essential RPCWS due to failures within the system. A fault tree depicting the failure mechanisms possibly leading to such an event is provided in Fig. 6-12. The data base for quantifying the fault tree is given in Table A-7.

Failure of both the A and B trains of the RPCWS is dominated by common mode failure of both running and standby pumps in both trains. Also contributing to RPCWS failure is failures of the temperature control circuit bypassing reactor plant cooling water around the heat exchanger.

While no automatic plant trip is required or provided following loss of RPCWS, timely operator action is expected in shutting down the plant and initiating a cooldown in order to minimize the heatup of the uncooled PCRV. This action and the subsequent range of response possibilities are depicted in the event tree of Fig. 6-13.

Event 2 considers whether the plant is successfully placed in a shutdown cooling mode using the main loops. Failure to successfully initiate shutdown cooling could be caused by either the operators failing to take appropriate action (1×10^{-3} per demand) or any one of 14

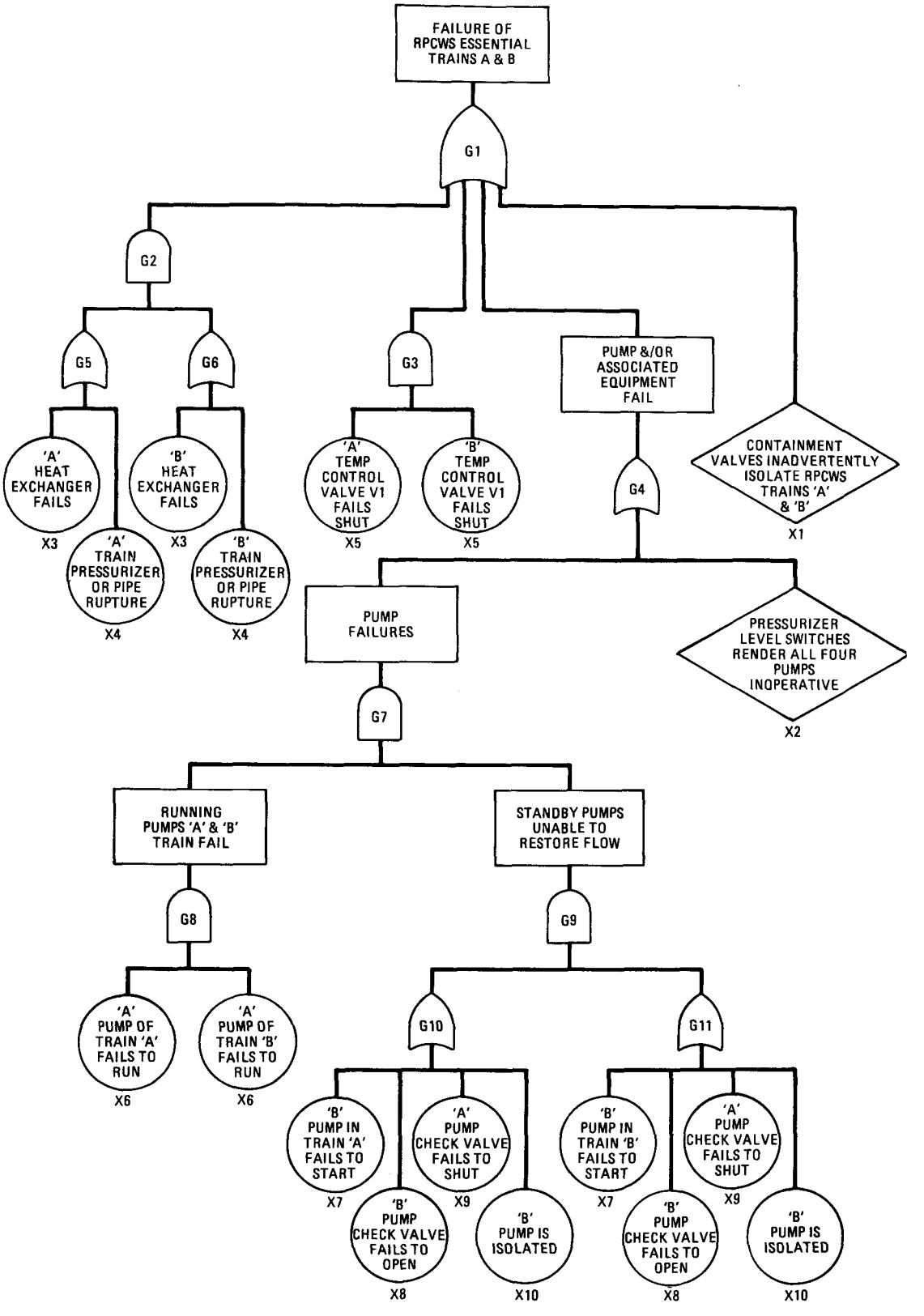

Fig. 6-12. Failure of RPCWS essential trains A&B

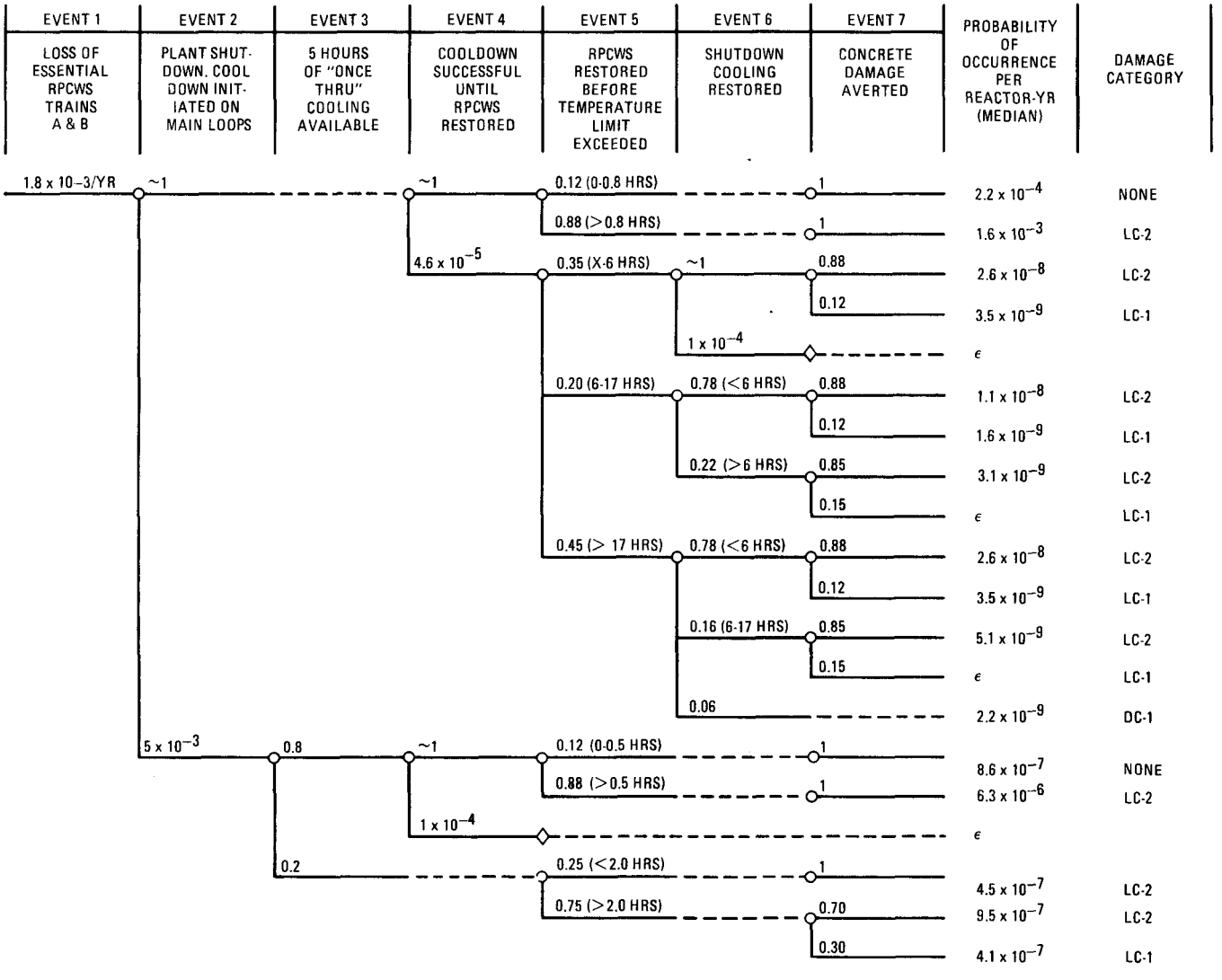

Fig. 6-13. Event tree for loss of essential RPCWS

actuated valves failing to operate ($3 \times 10^{-4}/D \times 14$) for a total failure probability of 5×10^{-3} per demand.

However, even if shutdown cooling is not successfully initiated, so long as the cause was not failure of the operators to take appropriate action, once-through cooling of the steam generators can still be provided for 5 hours. During this 5 hours, considered in event 3, repairs of both the essential RPCWS and the main cooling loops can be undertaken.

If the operators have failed to correctly diagnose the situation and take corrective action, elevated PCRV temperatures and concrete degradation cannot be averted. If, however, operator response is appropriate, the transient consequence is dependent upon maintaining the cooldown of the primary helium loops or restoring the RPCWS.

Given that plant shutdown and initiation of shutdown cooling is successful, event 4 considers whether or not cooling can be maintained until the RPCWS is restored. Under these conditions a failure to maintain cooling implies not only a failure of shutdown cooling to continue running, but a failure of the AHRS to start. In those branches where a valve failure prevented initiating a long-term cooldown, event 4 considers whether the AHRS starts after the 5 hours of once-through cooling.

Even if main loop cooling fails however, shutdown cooling can be provided by the AHRS so long as the cause of the main loop failure is not due to a failure in the nonessential RPCWS. If this were the case, motor cooling to the auxiliary circulator would be unavailable.

A fault tree depicting failure mechanisms of the main loops in a shutdown cooling mode is given in Fig. 6-14. The data base is provided in Table A-8. The RPCWS repair data base is contained in Table A-9.

Event 5 considers whether the RPCWS is restored prior to the onset of damage. As discussed in Section 5 the time available to restore

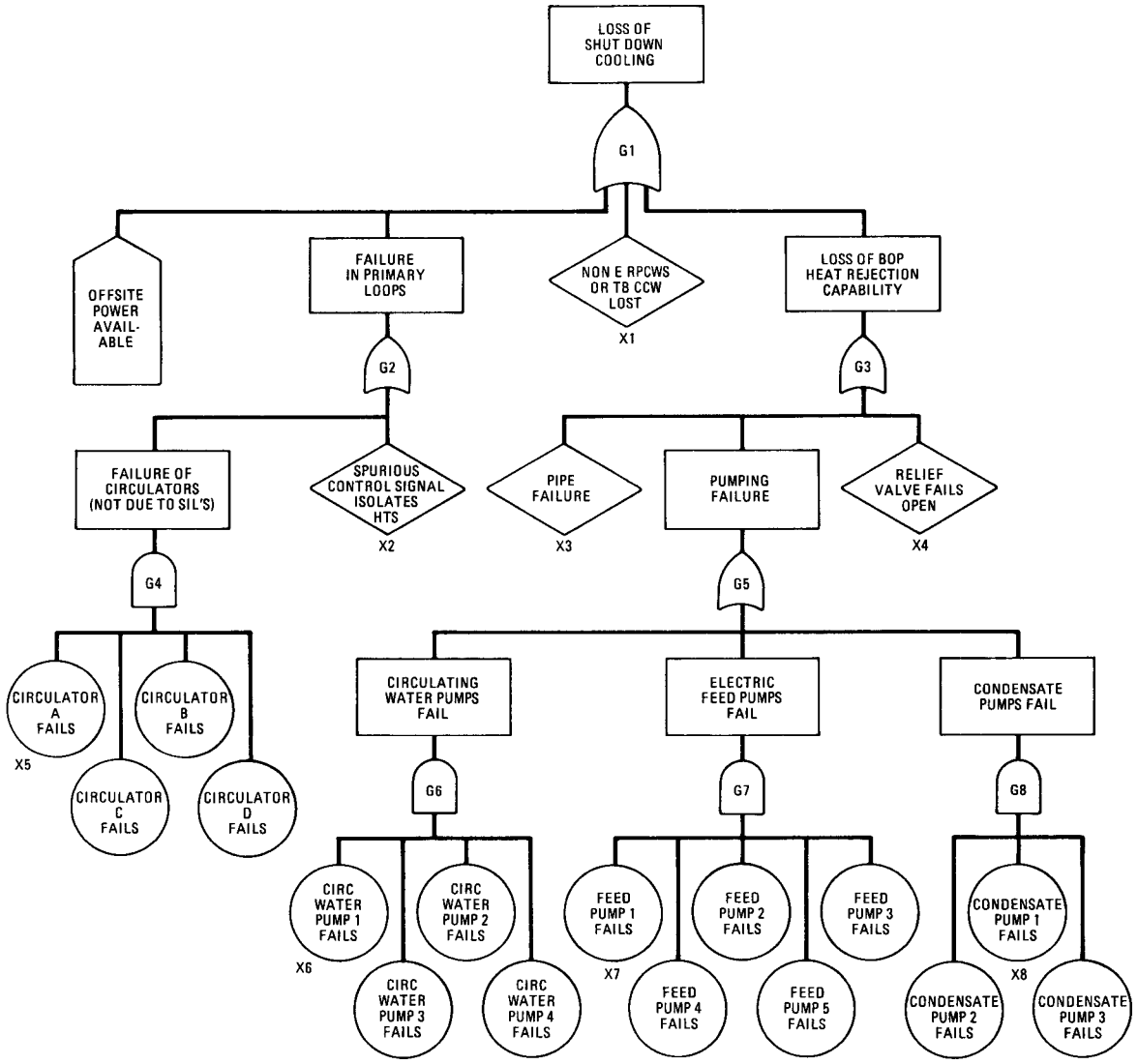

Fig. 6-14. Fault tree for loss of shutdown cooling in Event #3

RPCWS and liner cooling is dependent on the preceding events; in particular cooling history. If the plant has been shutdown and core cooling maintained, the probability of restoring reactor plant cooling water before some time after it failed is just a function of the component repair rates within the system.

In those cases where core cooling cannot be maintained until the RPCWS is restored, the probability of restoring RPCW in some additional length of time is given by

$$P(5|\overline{4}) = \frac{P(5 \cap \overline{4})}{P(\overline{4})} \quad ,$$

the solution of which has been shown in Section 6.3.3.

Even if the RPCWS is not restored quickly, the heatup of the PCRV concrete can be mitigated by restoring core cooling. Event 6 considers the distribution of shutdown cooling restoration. Note here that due to the high reliability and redundancy of the HTGR cooling systems, the only failure mechanisms in Fig. 6-14 that lead to a significant probability of loss of shutdown cooling are failures in the nonessential reactor plant cooling water system. As discussed earlier the reason for this is the loss of nonessential RPCWS takes the main loop circulators out of service; while in conjunction with the loss of essential RPCWS, operation of the auxiliary circulators is precluded. Therefore, recovery of shutdown cooling in event 6 is governed by repair of the nonessential RPCWS, gates G2 and G6 in Fig. 6-8.

Finally event 7 considers the probability that repair of the PCRV is averted. The probabilities of event 7 are based on the curve shown in Fig. 6-11 and the discussion of concrete heating following liner cooling failure given in Section 7.

6.3.5. Graphite Fuel-Element Damage

The functions of the fuel elements are to contain fuel and burnable poison pins, provide structural support, bear the dynamic and static loads from coolant flow, maintain alignment of coolant and control poison channels, and accommodate easy removal and replacement by the fuel handling machine. The fuel elements are expected to perform the above-mentioned functions during normal operation, expected transient, shutdown, and seismic loading conditions.

A failure to perform these functions can result in plant downtime and resultant investment risk. Failure to perform could result from damage of fuel elements by three important sources of loads: thermal gradients, irradiation induced dimensional changes and earthquakes. During normal operation, the fuel elements are subjected to both thermal and irradiation induced strains. The high creep rate during operation will cause the equivalent of a reversed thermal gradient and therefore resultant high stresses at shutdown. The fuel blocks are subjected to dynamic loads during seismic events.

The frequency assessment for fuel element damage considered four generic scenario types: plant operating, plant shutdown, earthquake occurrence with the plant operating, and earthquake occurrence with the plant shut down. Given a scenario type and its associated load conditions, the conditional probability that a fuel element is in a specified damage condition is described by the graphite structural fragility model developed in Ref. 6-11. In this model, the damage condition is divided into four discrete categories: (1) a no damage range, (2) a micro-cracking range which is characterized by no visible structural cracks and no significant loss of structural integrity, (3) a macro-cracking range characterized by visible but limited cracks involving no element fracture and no compromise of the element functional integrity, and (4) an offset shear damage range characterized by longitudinal shearing fracture patterns which do begin to compromise the element functional integrity, and rubbling of the element into multiple fracture segments

(along axial and horizontal shear planes) causing extensive structural failure of the block.

Each damage category is defined by a minimum, ρ_{min}, and a maximum, ρ_{max}, stress to strength ratio. The stress to strength ratio, ρ, is a measure of the block behavior in a stress field. The variance in the calculated stress and the measured block strength is described by the function $f(\rho)$, where $f(\rho)d\rho$ is the probability that the stress to strength ratio is within the interval ρ and $\rho + d\rho$. The probability, P_B, that the performance of a fuel element is in a given damage category is then given by,

$$P_B(\rho_{min} \leq \rho < \rho_{max}) = \int_{\rho_{min}}^{\rho_{max}} f(\rho)d\rho \quad .$$

The available experimental data on graphite fuel-element damage under thermal-irradiation and static loading conditions were used to support the fragility model.

The frequency assessment considered only the control fuel element as it has been concluded that, due to the weakening effect of the larger hole sizes in these blocks, the risk from control-fuel-element damage is more important than from standard fuel element damage with respect to investment risk target compliance. Four scenario types were considered. These were: earthquake during operation, earthquake during shutdown, normal plant operation, and a normal plant shutdown. The mean frequency estimates for these four scenario types were made with techniques indicated below.

The frequency for control fuel element damage is predicated upon the formulation:

$$\lambda_i = \lambda_{Ei}\ P_S\ P_B(1 \leq \rho < 1.5); \quad \text{offset shear} \quad ,$$

$$\lambda_i = \lambda_{Ei} P_S P_B(\rho \geq 1.5); \quad \text{rubbling} \quad ,$$

where λ_i = freqeuncy of damage of control fuel element during event i, where i=1 is seismic, i=2 is shutdown, and i=3 is normal operation,

λ_{Ei} = frequency of occurrence of event i, seismic, shutdown, and normal operation,

P_S = probability that the plant is in operation or shutdown given the event i,

$P_B(1 \leq \rho < 1.5)$ = conditional probability ofoffset shear in at least one control fuel element, given the plant status and the initiating event.

$P_B(\rho \geq 1.5)$ = conditional probability that at least one control fuel element is rubbled, given the plant status and the initiating event.

For the case of earthquakes, the plant status probability P_S equals 0.77 for plant operation and 0.23 for plant shutdown. Occurrence frequencies for earthquakes, $\lambda_{E1}(\alpha_1 \leq \alpha < \alpha_2)$, having a relative magnitude between α_1 and α_2 were obtained from the seismic intensity distribution discussed in Ref. 6-11. For a given relative magnitude range, it was postulated that ground motion at the site would correspond to the mean relative earthquake magnitude within the specified range. Earthquake occurrence frequencies and mean relative magnitudes are given in Table 6-1 as functions of α_1 and α_2.

In the case of shutdown, the plant shutdown frequency λ_{E2} is 3.75 per reactor year and the conditional probability that the plant is shutdown P_S is 1.0.

TABLE 6-1
EARTHQUAKE OCCURRENCE FREQUENCIES AND MEAN RELATIVE MAGNITUDES

Relative Earthquake Magnitude[a]		$\lambda_E(\alpha_1 \leq \alpha < \alpha_2)$ (per reactor yr)	Mean Relative Earthquake Magnitude
α_1	α_2		
0.4	1.0 (operational basis earthquake)	7.7×10^{-4}	0.59
1.0	2.0 (safe shutdown earthquake)	2.0×10^{-5}	1.28
2.0	4.0	8.1×10^{-7}	2.52
4.0	∞	1.4×10^{-7}	5.07

[a] Magnitude = g (expected)/g (operational basis earthquake).

For the case of normal operation, the probability per reactor year that the plant operates, λ_{E3}, is approximately 1.0 per reactor year, since the probability that no period of plant operation occurs during a one-year interval is extremely small. The conditional probability P_S that the plant is operating is 1.0.

Mean frequency estimates for each scenario appear in Table 6-2. The first two columns in Table 6-2 exhibit lower (α_1) and upper (α_2) bounds of the relative seismic magnitude. The relative seismic magnitude (α) is defined as the ratio of the actual ground acceleration to the OBE ground acceleration. The first entry in Table 6-2 corresponds to no seismic disturbance. The remaining entries cover the relative earthquake magnitude range from $\alpha = 0.4$ to ∞. A cutoff of 0.4 is introduced because the vast majority of earthquakes in this region are imperceptible to humans, and even at a 0.4 relative magnitude are not expected to damage typical commercial or residential structures.

The third column in Table 6-2 contains the plant status. A distinction is made between whether the plant is operating or shutdown because the shutdown stresses induced by a reactor trip exceed those encountered when the reactor is at power.

The last two columns contain the mean frequency, per reactor year, that the control element breakage involves offset shear or rubble, respectively. Offset shear occurs when the performance parameter (ρ) is in the range, 1 to 1.5, while rubble is expected when $\rho \geq 1.5$.

Most tabulated entries have a mean frequency below 10^{-6}/reactor year and are symbolized by the Greek letter, "δ". Such low frequency accidents have a negligible impact on investment risk target compliance, and have not been further quantified.

The probability of inducing an offset shear condition in a graphite control element solely as the result of thermal and irradiation induced operation and shutdown stresses is negligibly small. The basis for this

TABLE 6-2
MEAN FREQUENCY ESTIMATES FOR CONTROL BLOCK BREAKAGE

Relative Earthquake Magnitude[a]			Mean Frequency per Reactor Year	
Lower Bound (α_1)	Upper Bound (α_2)	Plant Status	$1 \leq \rho < 1.5$ (Offset Shear)	$1.5 \leq \rho$ (Rubble)
0	0	Operation	δ[b]	δ[b]
		Shutdown	δ	δ
0.4	1.0 (operational basis earthquake	Operation	δ	δ
		Shutdown	5.3×10^{-6}	δ
1.0	2.0 (safe shutdown earthquake	Operation	δ	δ
		Shutdown	δ	δ
2.0	4.0	Operation	δ	δ
		Shutdown	δ	δ
4.0	∞	Operation	δ	δ
		Shutdown	δ	δ

[a] Magnitude = g (expected)/g (operational basis earthquake).

[b] δ denotes mean frequencies below 10^{-6} per reactor year.

assessment is a crack propagation analysis using the TWOD code (Ref. 6-16). Although local finite element coolant channel web cracking is predicted, the subsequent stress redistribution prohibits crack propagation across the entire block. In essence, the combination of stress relief and coolant channel holes serve as an arresting mechanism which limits cracking to localized areas of the fuel element. Because of this stress relief, additional (seismic) induced mechanical loads must be applied in order to generate an offset shear condition.

Therefore, the only accident in Table 6-2 with a mean frequency above 1×10^{-6}/reactor year is an offset control element shear initiated by a seismic event with relative magnitude between 0.4 and 1.0 which occurs while the plant is in a shutdown state (condition of highest residual stresses). The mean frequency for this scenario is 5×10^{-6}.

6.3.6. Primary Coolant Leaks

Primary coolant can leak from the PCRV to the containment via a variety of penetrations and connected instrumentation lines. The consequence of a leak depends on the leak size, which could range from very small (barely noticeable) to a full flow rupture (maximum area). In order to characterize the frequency of leak occurrences versus leak area, the PCRV penetrations and their sizes were identified. Also identified were instrumentation lines that could allow leakage of primary coolant to the containment.

Major penetrations (those greater than 10 $in.^2$ in area) are tabulated in Table 6-3. One hundred twenty-eight were identified for the 2240 MW(t) HTGR-SC/C. The penetrations can be assigned to four groups according to maximum size. The total frequency of a full flow area penetration rupture is taken to be 10^{-7}/yr. This is the value that was used in Ref. 6-5, and is the same as the median assessment for steel pressure vessels. Each penetration is assumed to be equally likely to rupture, so has a frequency of $10^{-7}/128$ per year. Then Group I failures occur eight times as frequently because there are eight penetrations

TABLE 6-3
PENETRATION GROUPINGS AND LEAK FREQUENCIES FOR 2240 MW(t)

	No.	A_{max} Maximum Area ($in.^2$)	λ_{max} Frequency of Disruption per year	Group	λ_{min} Frequency of Leak per year	A_{min} ($in.^2$)	Type Seal
Major Penetrations (>10 $in.^2$)							
Steam generator top head	4	4185	3×10^{-9}	I	9×10^{-6}	1.26×10^{-4}	Weld
Steam generator bottom head	4	3269	3×10^{-9}	I	9×10^{-6}	1.26×10^{-4}	Weld
Refueling penetration	85	60	6.6×10^{-8}	II	2×10^{-3}	1.26×10^{-4}	Gasket
Element transport penetration	6	60	5×10^{-9}	II	1.4×10^{-4}	1.26×10^{-4}	Gasket
Side instrument penetration	11	12.6	9×10^{-9}	IV	2.6×10^{-5}	1.26×10^{-4}	Weld
Steam generator inlet temperature penetration	14	12.6	1.1×10^{-8}	IV	3.3×10^{-5}	1.26×10^{-4}	Weld
PCRV relief valve (rupture)	2	80	2×10^{-9}	III	5×10^{-6}	1.26×10^{-4}	Weld
Refueling evaluation and hoist	2	60	2×10^{-9}	II	5×10^{-6}	1.26×10^{-4}	Gasket
Total	128		1×10^{-7}				
Minor Penetratinos (<10 $in.^2$)							
Pressure taps plus valves	38	0.44	3.4×10^{-3}	VI	8.0×10^{-2}	1.26×10^{-4}	
Pressure taps plus valves	6	0.20	5.4×10^{-4}	VII	1.3×10^{-2}	1.26×10^{-4}	
Pressure taps plus valves	4	0.05	3.6×10^{-4}	VIII	8.4×10^{-3}	1.26×10^{-4}	
HP-HTF	4	4.9	5×10^{-7}	V	1.0×10^{-3}	1.26×10^{-4}	
HP-HTA	4	4.9	5×10^{-7}	V	1.0×10^{-3}	1.26×10^{-4}	
Moist monitor line	4	0.05	4×10^{-4}	VIII	7×10^{-3}	1.26×10^{-4}	
Moist monitor module (can be isolated)	4	0.05	8.3×10^{-2}	VIII	2.9×10^{-1}	1.26×10^{-4}	
Moist monitor return	1	0.44	1.5×10^{-2}	VI	3.5×10^{-2}	1.26×10^{-4}	
Total	65						

assigned to Group I. Other groups of penetrations fail with a frequency proportional to the number of penetrations in the group. Since Group II penetrations are the most numerous, they are the most likely to fail. Alternative methods for evaluating penetration failure frequency might consider penetration size or type, i.e., welded versus gasketed, but Group II penetrations would probably still dominate in frequency.

The frequency of small leaks in the major penetrations is based on the type of penetration seal, i.e., whether welded or gasketed. Welded penetrations leak 3000 times more often than they rupture, while gasketed penetrations leak 3×10^4 times more often than they rupture (Ref. 6-17, Table 2-4 for tanks and pressure vessels).

The area of a small leak has been defined to be that which would allow leakage at such a rate as to diminish the containment accessibility below 40 hours per week. Reference 6-18 has shown that 40 hours of accessibility results when circulating activity containing 14,000 curies of Krypton 88 is present in the primary coolant, and the coolant leaks out of the PCRV at 0.01%/day (3.65%/yr).

It is expected that circulating activity levels will be a factor of 20 less than the Ref. 6-18 levels. Thus, a factor of 20 higher leak rate could be tolerated, or 0.2% per day. There are 14,890 kg (32,820 lbm) of helium in the PCRV. Thus the minimum tolerable leakage is,

$$\dot{m}_{min} = (0.2\%/day)(32{,}820\ lbm) = 7.6 \times 10^{-4}\ lbm/sec \quad .$$

A small leak will be choked, and will obey the equation,

$$\dot{m} = \frac{CAP}{\sqrt{T}} \sqrt{\frac{gk}{R} \left(\frac{2}{k+1}\right)^{k+1/k-1}} \quad ,$$

where $k = C_p/C_v$.

For depressurizations at the hot leg and cold leg, this equation yields flow rates of 5.28 and 6.73 lbm/sec/in.^{2}, respectively. On the average, $\dot{m}/A$ = 6.01 lbm/sec/in.^{2}. Then the area that gives $\dot{m}_{min}$ is A_{min} = 1.26 x 10^{-4} in.^{2}.

Minor penetrations and equipment lines are also listed in Table 6-3. Sixty-five were identified that normally carry primary coolant. Other lines that could contain primary coolant under certain conditions were not included, since the probability that they would leak primary coolant is significantly lowered by the small fraction of time that they might contain it. Again, the penetrations and lines are grouped according to maximum leakage area. The frequency of a disruptive leak is found for each group from data in Ref. 6-17 for the appropriate kind of valve or line or equipment. The frequency of smaller leaks is similarly taken from data, and is typically 2 to 3 orders of magnitude higher than the frequency of disruptive failures. The area for the smallest leak is A_{min} = 1.26 x 10^{-4} in.^{2}, as described above for major penetrations.

The frequency of leaks versus size is found by adding the contributions from each group, as shown in Fig. 6-15. For each group two points are plotted, representing the maximum leak area and frequency of disruptive leak, and the minimum leak area and frequency of leakage. A straight line interpolation between the two points on a log A versus log F plot has been found to give the most reasonable results for leak size versus frequency for that group. The accumulation of all the group contributions gives a curve that represents the frequency that a leak exceeds a given size.

An idea can be gained of the dominant sources of leaks by comparing Table 6-3 with Fig. 6-15. Large penetration failures (A > ~5 in.^{2}) are expected to occur at a median frequency of less than 10^{-6}/yr. Leaks of size 0.44 in.^{2} < A < ~5 in.^{2} are dominated by sources in Groups II and V, refueling penetrations and helium purification system lines. Below those sizes, down to about 0.05 in.^{2}, Group VI leak sources dominate,

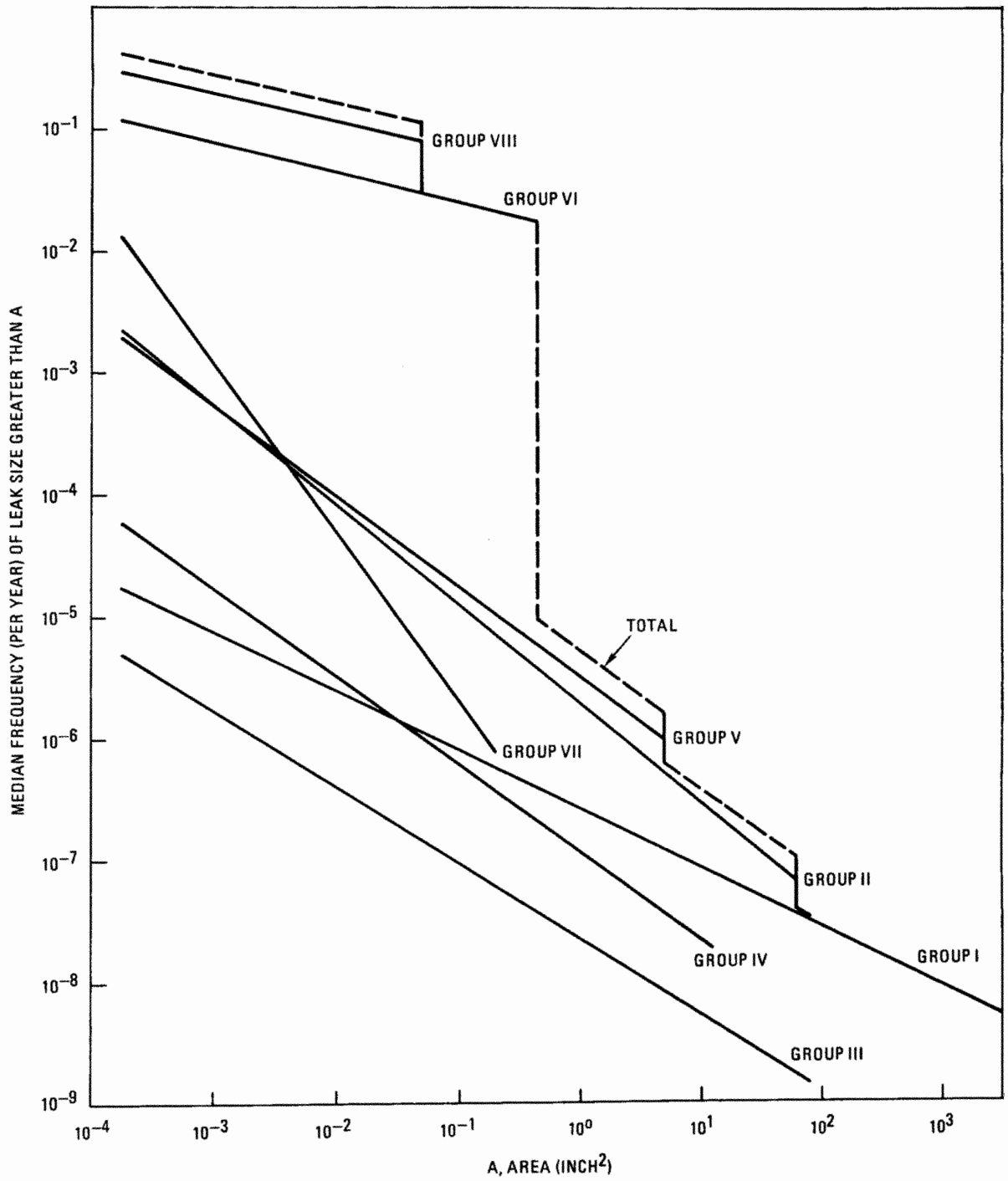

Fig. 6-15. Frequency of leaks vs. area

which are 3/4 in. pressure instrumentation lines and isolation valves. Even smaller leaks are dominated by source in Groups VIII and VI, 1/4-in. and 3/4-in. pressure instrumentation.

Three categories of primary coolant leaks have been treated here, varying by the magnitude of release, which relates to leak size. As will be discussed further in Section 7.2.4, leaks that involve the release of 75% to 100% of the primary coolant can result from leak areas of 0.6 $in.^2$ or greater. From Fig. 6-15 the frequency of a leak with an area greater than 0.6 $in.^2$ is,

$$\lambda(A > 0.6) = 9 \times 10^{-6} \text{ per year} \quad .$$

Leak areas in the range of 0.06 to 0.6 $in.^2$ can result in the release of 20% to 75% of the primary coolant to the containment. From Fig. 6-15,

$$\lambda(A > 0.06) = 0.029 \text{ per year} \quad .$$

The frequency of leaks in the area range is,

$$\lambda(0.06 < A < 0.6) = \lambda(A > 0.06) - \lambda(A > 0.6) = 0.029 \text{ per year} \quad .$$

Leak areas in the range of 0.006 to 0.06 $in.^2$ can result in the release of 4% to 20% of the primary coolant. Again,

$$\lambda(A > 0.006) = 0.186 \text{ per year} \quad ,$$

and

$$\lambda(0.006 < A < 0.06) = 0.157 \text{ per year} \quad .$$

The frequency of small leaks is calculated to be so high (they are expected more than once in the life of the plant) and the consequence

sufficiently low that they are judged to be more appropriately considered as contributors to unavailability and not investment risk.

6.3.7. Investment Risk From Steam Generators

Several potential risk contributors stemming from the steam generators were identified during the course of this assessment. These risk contributors can be roughly lumped into two broad categories: outages resulting from the required replacement of a damaged or degraded steam generator and outages brought on by radiological releases following steam generator leaks.

In the first category, steam generator damage as a result of an abnormal, beyond design basis thermal transient was considered and the analysis is discussed in Sections 6.3.7.1 and 7.2.5.1. A second mechanism recognized as having the potential to require steam generator replacement is failure of the steam generators to perform as anticipated as has been the history in PWR steam generators. This second mechanism while recognized as potentially important is beyond the scope of the current work.

In the second category the transient referred to in the recent HTGR Safety Assessment (Ref. 6-12) as SG-2, and identified in that study as leading to radiological release through a leaking steam generator, has been reviewed for its investment risk potential.

In none of the above cases has any significant investment risk contributor been identified. A discussion of these cases follows.

6.3.7.1. Steam Generator Thermal Shock. Estimates as to the time and cost of replacing an HTGR steam generator vary. However, the difficulty in removing and reinstalling this 350-ton component in the PCRV suggests the possibility of an extended outage should replacement become necessary. Furthermore, the long lead time in manufacturing a replacement steam generator, should a spare not be available, could result in either

a period of reduced power operation or outage of even longer duration. Because of these considerations, abnormal transients which threaten major steam generator damage were identified as likely candidates for contributing to the investment risk envelope.

The HTGR steam generator is designed with substantial margin and multiple engineered protective features are incorporated in the plant design to prevent operations that could threaten steam generator integrity. Nevertheless a screening of potential failure scenarios indicated that circulating hot helium through a dry steam generator has the potential for occurrence at non-negligible frequencies.

The transient of concern occurs while the plant is at power producing steam. A loss of steam generator water inventory is then postulated to occur with sufficient rapidity to necessitate automatic loop or plant trip and preclude effective operator intervention. Should the automatic plant features fail to shut off the helium circulator, a rapid heatup of the dry steam generator will occur.

Figure 6-16 illustrates the general workings of the steam generator, steam generator dump feature, helium circulator, loop steam temperature control system, and their basic interfaces. As circulator and circulator controls have as yet not been fully defined, the figure should be viewed as a projection of where current design philosophy and HTGR design history is likely to lead. To depict more clearly both qualitatively and quantitatively the combinations of failures that must occur among these systems prior to the occurrence of the above-described transient, a fault tree (Fig. 6-17) was constructed. While Table A-10 summarizes the various values used in quantifying the fault tree, the fault tree construction and quantification was performed as described below.

The only mechanisms deemed capable of providing the required rapid loss of steam generator inventory were operation of the steam generator dump valves and rupture of feedwater piping. Of these, fault X1 steam

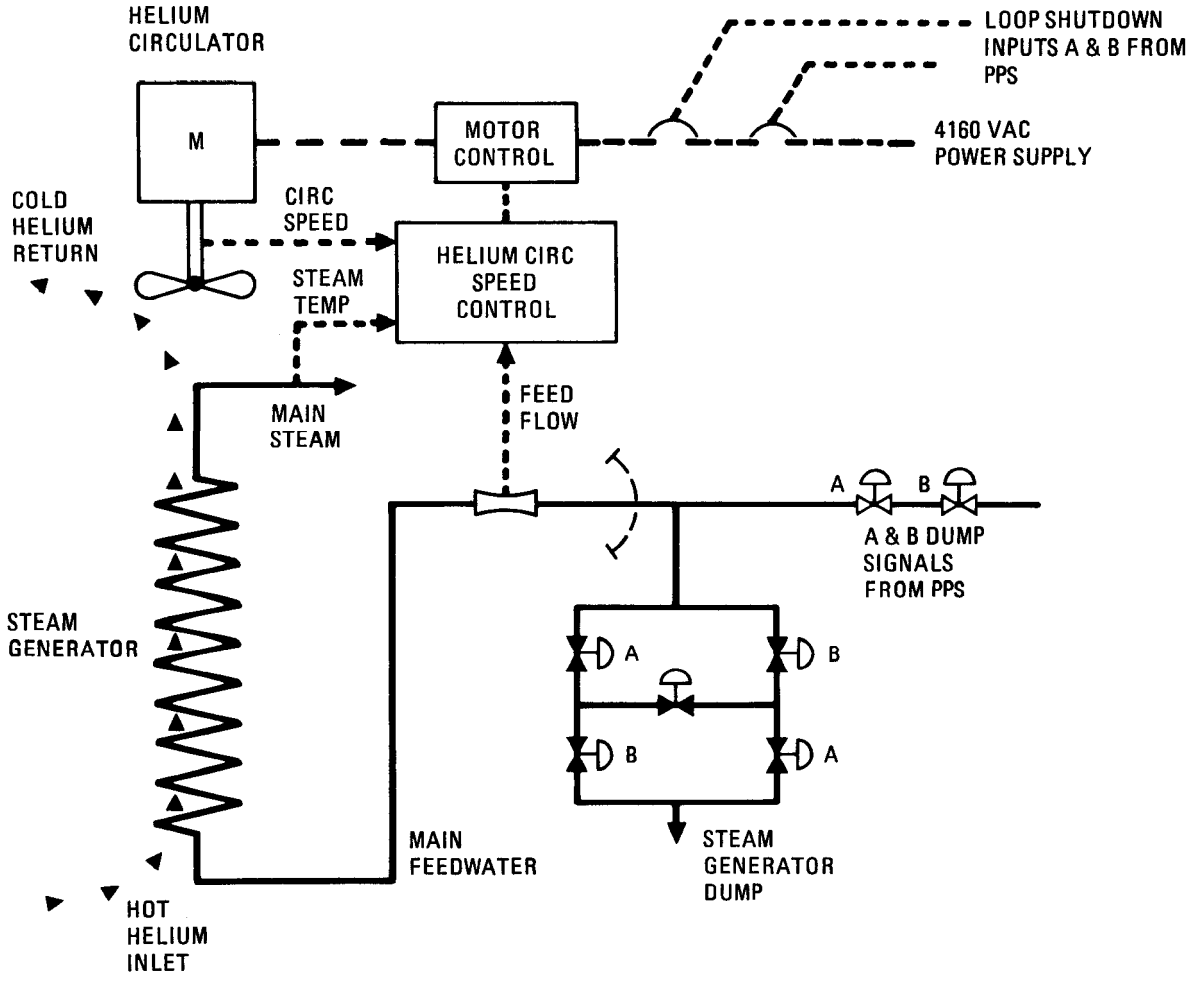

Fig. 6-16. Steam generator dump system

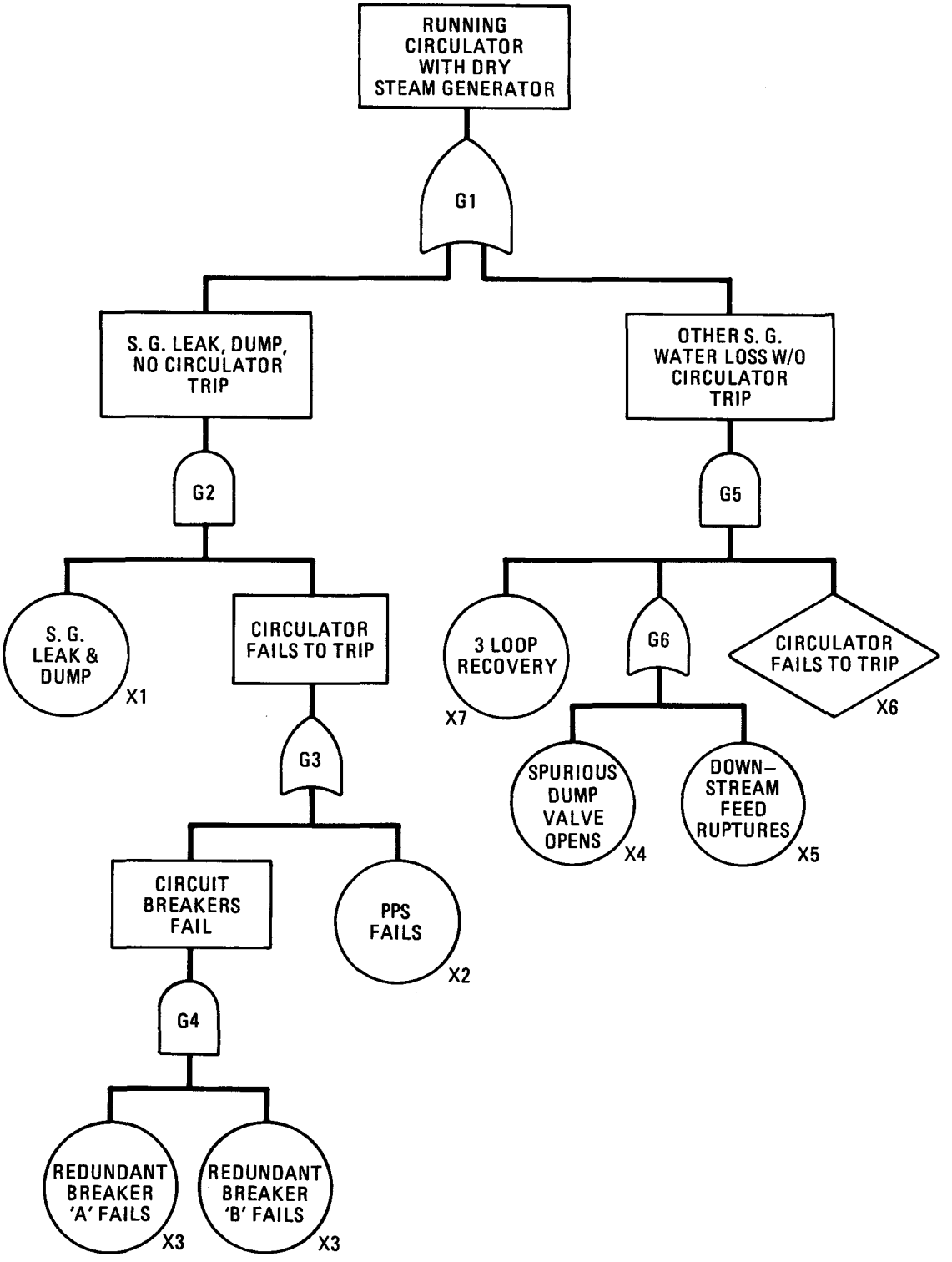

Fig. 6-17. Steam generator heat-up fault tree

generator dump as a result of a steam generator tube leak and successful moisture detection has the highest probability. As assessed, the frequency of occurrence of this event is 0.3 per year. A spurious opening of the dump valves (fault X4) or rupture of the feedwater lines (fault X5) also can lead to a rapid loss of steam generator water inventory, however, the frequency of occurrence for these events is orders of magnitude less than that of X1.

As described, not only must the steam generator inventory be lost, but plant safety and control systems must fail to trip the circulator for steam generator damage to occur. During a moisture ingress event, steam generator dump is accompanied by a loop trip including shutoff of the circulator. Two categories of failure are identified in the fault tree of Fig. 6-17. The first of these is failure of the plant protective system to provide a trip signal to the circulators. The high reliability of the redundant PPS circuits makes this event highly unlikely particularly given that the PPS has successfully provided a signal to open the dump valves. The probability of this occurrence is conservatively estimated to be 9×10^{-6} per demand based on estimates of total PPS function failures in Ref. 6-5. The second category, circulator trip failures, is based on the simultaneous failure of the circulator feeder breakers pictured in Fig. 6-16 to open despite PPS demand. Failure of a single circuit breaker to change state on demand is given as 1×10^{-3} per demand in Ref. 6-6. Simultaneous occurrence of two unlikely failures such as this is expected to be dominated by common mode failures. Based on the available record of under voltage coil failures in Westinghouse scram breakers (Ref. 6-19) and breaker operation related to pump starts (Ref. 6-7), the beta factor between such circuit breakers is estimated to be 0.2. Thus, the probability of simultaneous failure of both circuit breakers to open on demand is 2×10^{-4} per demand.

Spurious opening of the dump valves or a rupture of feedwater piping in and of themselves do not cause the PPS to trip the circulator as in the case described above. However, loop trips on high superheat steam temperature, high circulator outlet temperature, or mismatched

feedwater flow/circulator speed (see Fig. 6-18) all have the capability to initiate a circulator trip signal following a loss of steam generator water inventory. The probability of successful circulator trip is then similar to that discussed previously.

Note that because the occurrence frequencies for spurious valve openings and feedwater line ruptures are very low, their contribution to risk as compared to that from steam generator leak followed by successful dump is negligible. Thus, the point estimate for frequency of occurrence of these events is 6×10^{-6} per reactor year.

6.3.7.2. Steam Generator Release, SG-2. Reference 6-12 identifies a steam generator tube leak followed by a failure of the dump valve system to shut after exhausting the steam generator inventory to atmosphere as the dominant steam generator contributor to safety risk. This transient has been reviewed for its potential contribution to investment risk.

The transient initiating event is a steam generator tube leak, the same event mentioned in Section 6.3.7.1. From Ref. 6-12 only 10% of the tube leaks are expected to be large enough to be of concern in terms of leading to SG-2 type releases. Therefore, the median frequency of leaks of interest is 0.03 per reactor year.

Following a steam generator leak, the design plant response is as follows. The reactor is automatically tripped and the affected loop is isolated while core cooling continues to be provided by the remainder of the HTS. With the leaking loop isolated its associated dump valves (Fig. 6-16) open, discharging the steam generator inventory to atmosphere and limiting the water ingress to the primary coolant system. Once the steam generator blowdown is complete, the dump valves shut. If, however, the dump valves fail to shut, a pathway is available for primary coolant blowdown directly to the atmosphere. The probability of these valves to open but fail to shut is assessed at 2×10^{-4} per demand (Ref. 6-12). Therefore, the median frequency of such an event is given to be 6×10^{-6} per reactor year.

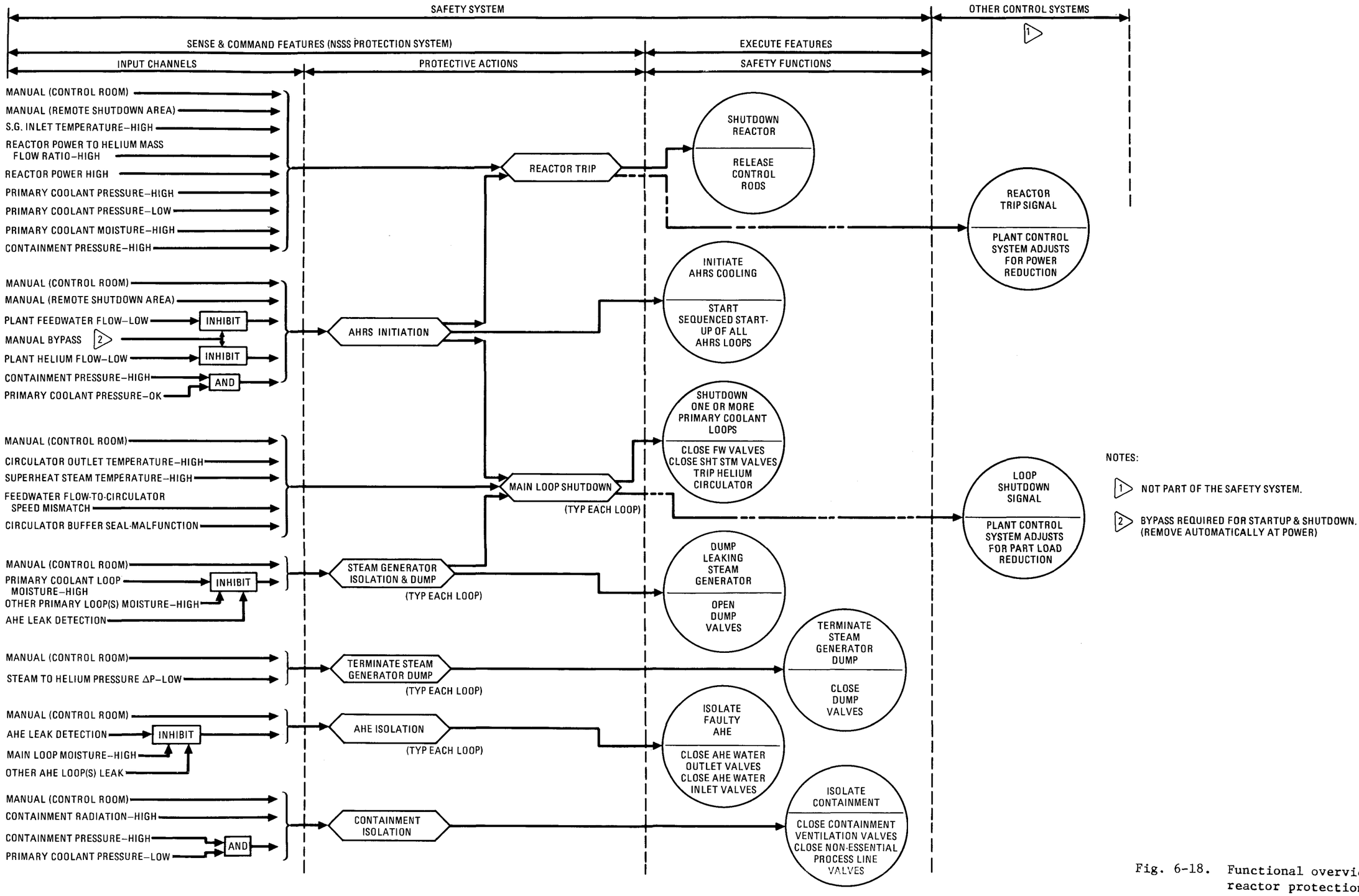

Fig. 6-18. Functional overview of reactor protection subsystem

6.3.8. Seismic Events

As a first order approximation for the 2240 MW(t) SC/C seismic activity data, the Zion Nuclear Power Generating Station site seismicity data is used. Zion is located in Lake County, Illinois. Seismic activities with peak ground accelerations (g) in the range of 0.075 to 0.335 g are considered. The HTGR operational basis earthquake (OBE) is 0.15 g and safe shutdown earthquake (SSE) is 0.30 g. Ground motion outside this range is judged to have insignificant investment risk. This range is broken down into five smaller ranges and mean frequencies were determined for each. Earthquake occurrence frequencies and relative magnitudes are given in Table 6-4 (Ref. 6-20).

Comparison of these seismic frequencies and magnitudes from the Zion study with those from AIPA (Ref. 6-4) found in Section 6.3.5 on graphite fuel element damage show excellent agreement. Frequencies agree within a factor of two and provide an independent verification of the seismic frequency data base. The data base for Zion seismic activity is provided in Table A-11 of Appendix A.

Four structural fragility classes have been developed in order to assess the extent of damage incurred by the HTGR-SC/C plant during a seismic event. The structural fragility classes each pertain to different plant structures. Structural fragility class 4 represents nonseismic building code category I structures designed to the uniform building code for zone 3 seismic activity. Structural fragility class 3 represents building code category I structures designed to withstand safe shutdown earthquakes. Structural fragility class 2 represents all plant equipment with the exception of electical switchyard gear which is represented by structural fragility class 1. A more detailed description of the structural fragility classes is given in Section 7.2.6.

TABLE 6-4
ZION SEISMIC OCCURRENCE FREQUENCIES AND MAGNITUDES

Seismic Activity Range	Peak Ground Acceleration ($\tilde{g}$)	Peak Relative Magnitude (g/0.15)	Mean Frequency (1/yr)
Seismic Activity 1	0.075 to 0.125	0.50 to 0.83	5.0×10^{-4}
Seismic Activity 2	0.125 to 0.175	0.83 to 1.17	1.4×10^{-4}
Seismic Activity 3	0.175 to 0.115	1.17 to 1.50	3.8×10^{-5}
Seismic Activity 4	0.225 to 0.275	1.50 to 1.83	1.2×10^{-5}
Seismic Activity 5	0.275 to 0.325	1.83 to 2.17	2.1×10^{-6}

In order to evaluate the probability P_{ij}, of damage in a given structural fragility class j, given the occurrence of seismic activity level i, the following equation is used:

$$P_j = (2\pi)^{-1/2} \int_{-\infty}^{z} e^{-1/2x^2} \, dx \quad ,$$

where

Z = standard normal variable

$$= \frac{\ell n \; m = \ell n \; m_o}{\beta}$$

and m = peak earthquake magnitude in ground acceleration, g,

m_o = median point of equipment or structural failure,

β = logrithmic standard deviation, $\ell n \; \sigma$.

This equation, in conjunction with the unrecovered costs associated with each structural fragility class, is used to generate a weighted function for the consequences of each seismic activity range (SA) seen in Table 6-4. This will be discussed further in Section 7.3.6.

6.3.9. Turbogenerator Failure

Reference 6-21 discusses turbogenerator failure data and classifies these failures into three general categories. The basis for this failure analysis is a data base extending over 92,000 years of combined nuclear and conventional steam turbine experience, along with over 7,000 years of jet engine experience. Data for the turbogenerator failure is summarized in Appendix A, Table A-13, and has been plotted in Fig. 6-19 to show the relationship between the occurrence frequency (ordinate) and the extent of machine damage (abscissa).

The extent of damage is defined as the number of blades, rows, or discs which fail in the incident. The three damage categories are

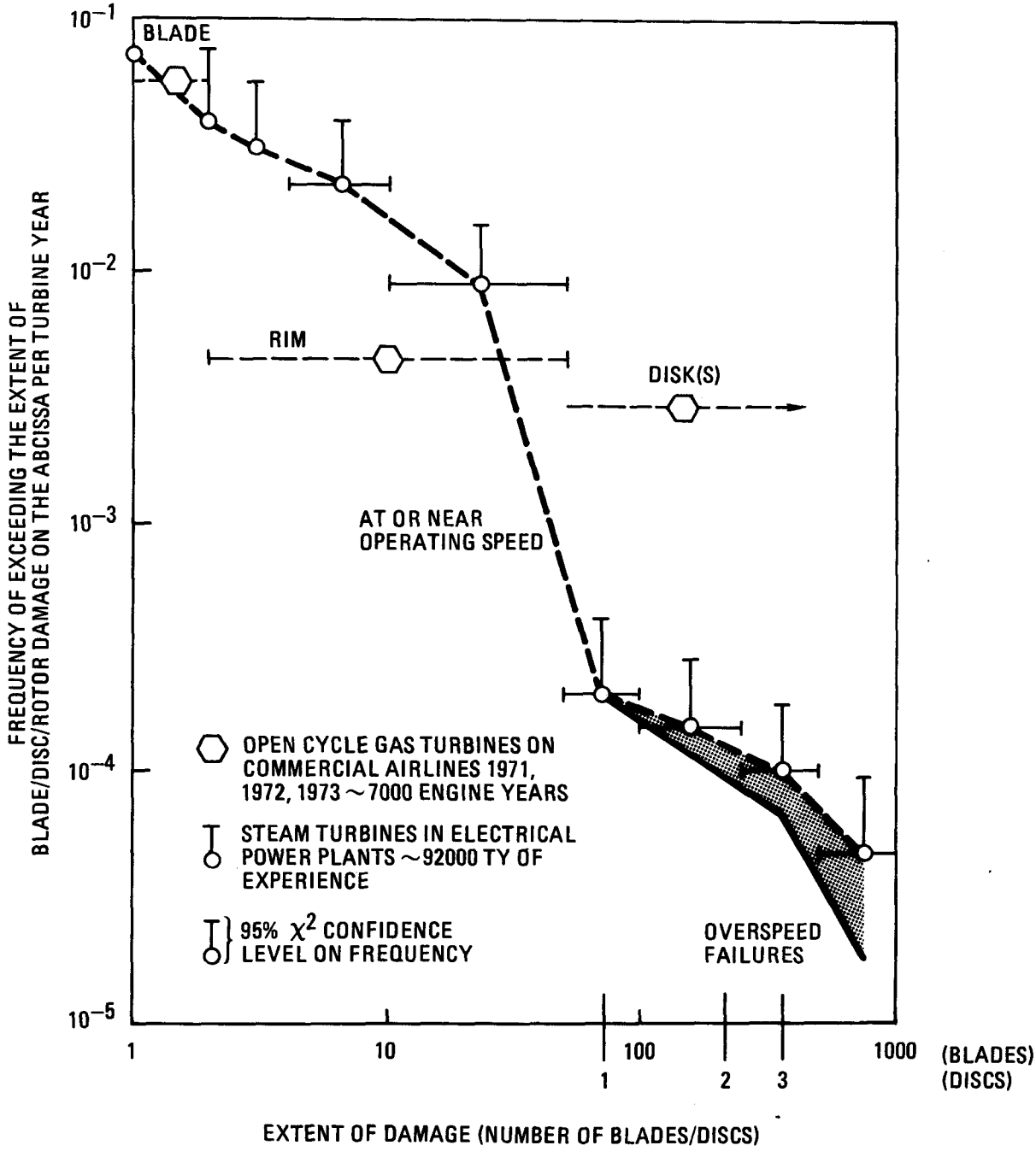

Fig. 6-19. Frequency of occurrence vs. extent of damage in turbines (generator faults excluded)

described below. The first category, damage category 3, is one blade failure up to a row of blades or several blades in different rows. The frequency of failure in category 3 ranges from 10^{-1} to 10^{-2}/machine-year. Turbine machine failure category 2 (in the occurrence frequency range of 10^{-2} to 3×10^{-4}/machine-year) includes cases of damage where multiple rows of blades, shrouds, or disc rims fail. Category 1, in the probability range of less than 3×10^{-4}/yr, may be termed catastrophic failure and is characterized by disc and machine housing failures. These failures may also result in missiles being thrown from the machine. Three basic failure types are described in the catastrophic failure experience base. These are generator failures at normal speed, turbine failures at normal speed, and machine overspeed failures.

Frequency of the HTGR turbogenerator set failure is based, of course, on time of operation. Since the 2240 MW(t) SC/C plant can be operated in either process or electrical modes, an effective capacity factor for the turbines must be established. Assuming equal time for both process and electrical operation, turbo set A (designated house load supplier) is assumed operational 100% of the time the plant is in a power production mode, while turbo sets B and C are assumed operational only 50% of the time the plant is in a power production mode. The operationally weighted failure frequencies for each turbogenerator failure category are presented in Table 6-5.

These results will most likely overpredict turbine failures for the HTGR-SC/C plant for two reasons. First, this data base includes nonnuclear plants. Second, since turbines built many years ago are included, the data contains failures eliminated in later designs.

6.3.10. Inadvertent Reserve Shutdown System (RSS) Insertion

The reserve shutdown system (Ref. 6-22) is designed to provide manual shutdown in the event that the control rods are inoperative. This system is actuated by "arming" and "region select" switches located an appreciable distance from each other. Shutdown may be achieved from

TABLE 6-5
HTGR TURBOGENERATOR DAMAGE CATEGORIES AND FREQUENCIES OF OCCURRENCE

Turbogenerator Damage Category	Description	Mean[(a)] Frequency (Turbo Set A) (1/yr)	Mean[(a)] Frequency (Turbo Set B or C) (1/yr)
Turbogenerator 3	Several blades brake, detection via vibration, operator shutdown	2×10^{-2}	1×10^{-2}
Turbogenerator 2	Multiple blade or limited disc failures with material ingestion, vibration causes operator shutdown	3×10^{-3}	1.5×10^{-3}
Turbogenerator 1	Multiple disc failure, catastrophic distruction of turbine, shutdown due to component deformation	1×10^{-4}	5×10^{-5}

[(a)]Turbo sets B and C operate only 50% of the time. Therefore, their failure rate is one-half that of turbo set A.

the remote shutdown area or the main control room. When both "arming" and "region select" circuits are closed, DC power is applied to two redundant fusible links. Breach of link continuity that results causes the hopper gate to open and boron balls to be released into the core. Once a hopper releases, an indication appears to inform the operator. To clean up the balls, the PCRV control rod penetration must be opened, the control rod drive removed, and the balls vacuumed. Investment consequences of RSS insertion is based on the downtime to repair hoppers and to remove the boron balls from the core. Electrical and mechanical surveillance is to be performed on the actuation system periodically.

The calculation of inadvertent actuation of the reserve shutdown system frequency is facilitated by construction of a fault tree. This can be seen in Fig. 6-20. Due to relatively modest experience base of Fort St. Vrain, such a phenomenological approach was necessary. To date one inadvertent hopper release has occurred at Fort St. Vrain (Ref. 6-23). The RSS hopper disc was inadvertently ruptured during the replacement of valve seats while shutdown. Not until after return to power was it determined that a hopper had released. There are two reasons why the HTGR-SC/C design is less susceptible to such a failure. First, the design contains no rupture discs or control valves. Instead, as described above, a fusible link actuation mechanism is used. Second, indication is provided to the operator when a hopper is released. This type of indication while not reducing the likelihood of the release reduces the likelihood of return to power with boron balls in the core.

Based on discussions with the RSS engineers, hoppers may be released individually or in banks (groups of hoppers). Consequently, it is assumed that as a minimum, one bank of five hoppers are released. Failure rates for electrical equipment used in the actuation circuits were taken from Ref. 6-24. Operator error was estimated to be once per 1000 demands (Ref. 6-5). Surveillance intervals for safety related instrumentation is assumed to be one month. The total frequency of release of one or more hoppers was determined by summing all frequencies of each scenario presented in Fig. 6-20. It is dominated by operator

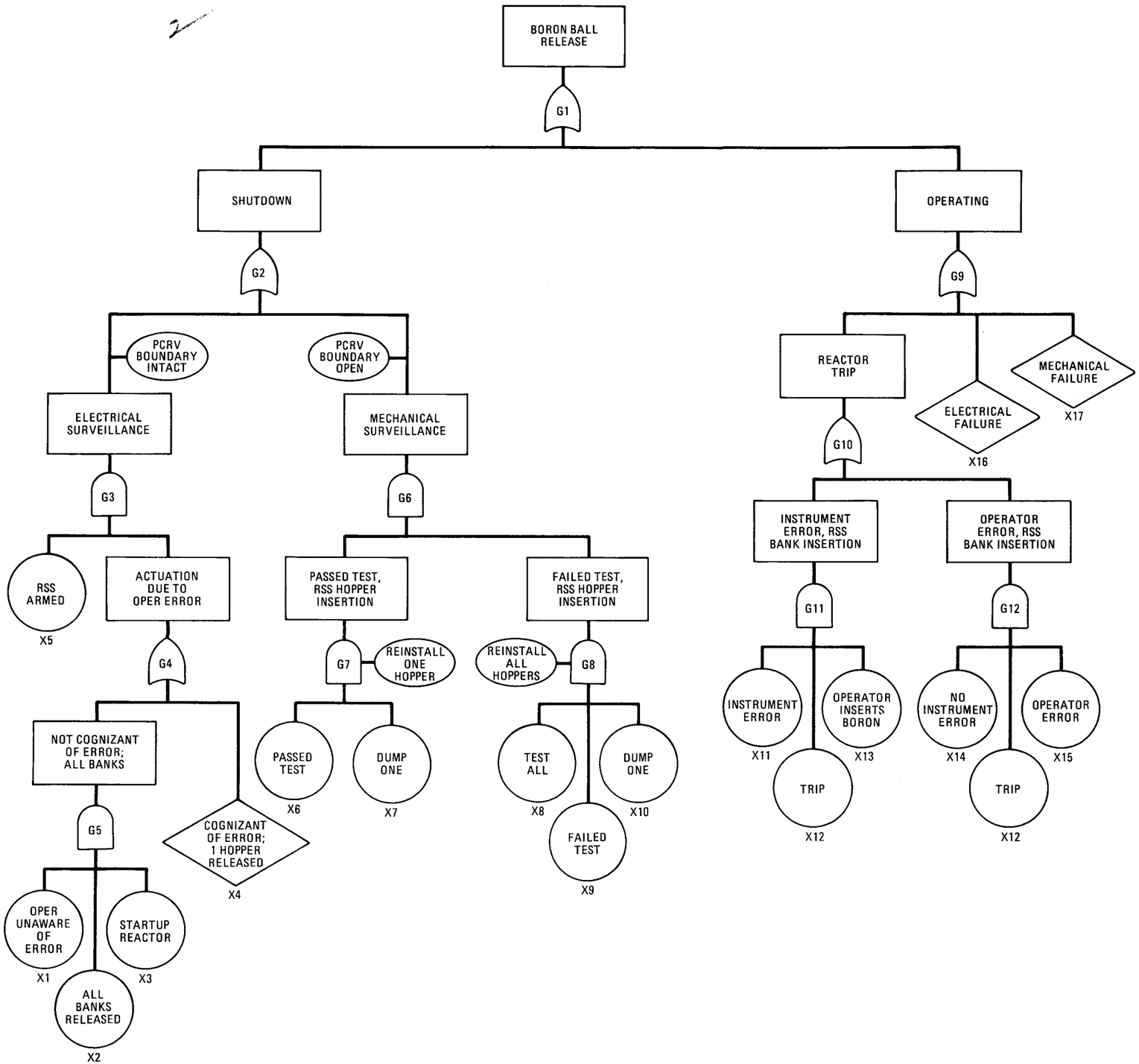

Fig. 6-20. Inadvertant RSS insertion fault tree

error during electrical surveillance testing. The assessed frequency of dumping one bank is ~2 x 10^{-1}/yr. In comparison, the likelihood of all hoppers being released is assessed at ~1 x 10^{-5}/yr. This failure mode depends on the operator not following the procedures and inadvertently releasing all hoppers. In order to release all hoppers, the operator must not be cognizant of any release. Otherwise, he would terminate testing until the problem was resolved. The data base for inadvertent RSS insertion is provided in Table A-14 of Appendix A.

6.4. UNCERTAINTY ANALYSIS

Uncertainty distributions from the reliability data base have been factored into all the fault tree and event tree analyses described in Section 6.3. A typical system level example can be seen in the cumulative distribution functions for the "failure to start" of the AHRS in Fig. 6-5. These distributions were generated with the STADIC computer program (Ref. 6-25) by propagating the component level reliability data in Table A-2, including uncertainty distributions, through the fault tree seen in Fig. 6-3. Fault tree uncertainties, such as that for the AHRS, were in turn incorporated into an event tree algorithm and combined by STADIC to generate median and mean branch frequency estimates, as well as upper and lower percentiles for the various plant damage category frequencies. Mean and median frequencies so generated are shown in Table 6-6 for selected damage categories.

The STADIC program performs Monte Carlo samplings of the independent probability distributions. Repeated solution of the event and fault tree algorithms using these samplings provides the complementary cumulative distribution function for an event sequence. To varying degrees, then, each of the event sequences have some uncertainty. This results in the median probability for the sequence not being equal to the product of the medians of the nodes. A similar effect is sometimes found where the sum of the median sequence probabilities for a damage category is not equal to the STADIC result for the sum. In this report, the STADIC results have been used.

TABLE 6-6
SELECTED CONSEQUENCE CATEGORY FREQUENCIES

Consequence Category	Frequency (per Reactor-Year)	
	Median	Mean
Interrupted Core Cooling		
DC-9	1.4×10^{-4}	4.0×10^{-4}
DC-8	2.7×10^{-6}	7.0×10^{-6}
DC-7	1.5×10^{-5}	3.7×10^{-5}
DC-5	1.9×10^{-6}	3.4×10^{-6}
DC-4	5.4×10^{-6}	1.4×10^{-5}
DC-3	2.0×10^{-6}	3.8×10^{-6}
DC-2	3.6×10^{-6}	8.5×10^{-6}
DC-1	1.6×10^{-5}	3.8×10^{-5}
Liner Cooling Loss		
LC-2	1.6×10^{-3}	2.8×10^{-3}
LC-1	1.5×10^{-6}	5.3×10^{-6}
Primary Coolant Leaks		
PC-3	1.6×10^{-1}	4.2×10^{-1}
PC-2	2.9×10^{-2}	7.8×10^{-2}
PC-1	9.0×10^{-6}	2.4×10^{-5}

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7. ACCIDENT CONSEQUENCES

The consequences of each sequence of events described in Section 6 can be evaluated in terms of the unrecovered cost to the utility or plant owner, due to actual costs to repair and decontaminate as well as downtime costs. This section describes those consequences. Section 7.1 describes the data used to evaluate the consequences of the event sequences. Section 7.2 describes the physical phenomena that occur during the various types of events, and the damage that can be incurred. The resultant plant downtime is discussed in Section 7.3, as well as the costs of recovery from the events including downtime costs and repair costs where appropriate. Uncertainties in these consequence results are discussed in Section 7.4.

7.1. DATA BASE

The consequence data include that used in transient models of plant thermodynamic and radiological response, as well as that used in the evaluation of recovery times, for such activities as repairs and decontamination, and the costs that result.

The thermodynamic data are those parameters and physical relationships that are typically used to analyze the plant response to plant transients and accidents, such as an interruption of core cooling or a loss of liner cooling. Computer codes used to analyze these events include RECA and RATSAM (Refs. 7-1 and 7-2).

Radiological data include expected fuel body and primary coolant circulating activities calculated for the LEU UCO fuel.

Seismic consequence data are conservatively based on similar data for the Zion nuclear plant (Ref. 7-3). Turbomachine data have been collected from nearly 400 years of light water reactor power plants, 92,000 turbine-years of experience from worldwide electrical plant steam turbines, and 7000 years of jet engine turbine data (Ref. 7-4).

Damage limits have been established based on licensing limits in Ref. 7-5, on communication with cognizant component designers, and on recent test results.

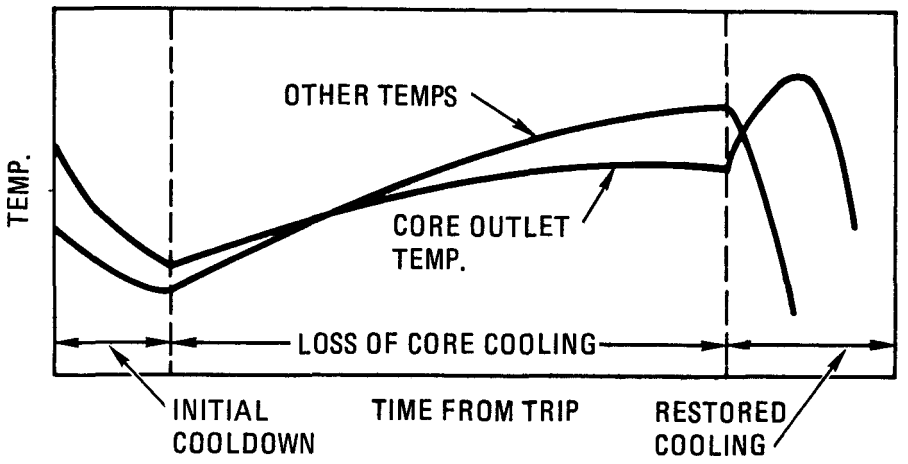
Downtimes have been estimated by cognizant design engineers, with the help of actual experience where available and applicable.

7.2. PHYSICAL PHENOMENA AND DAMAGE

7.2.1. Interrupted Core Cooling

Inspection of the event trees in Section 6.3 shows that a number of different branches result in interrupted core cooling. When core cooling stops, a thermal transient is initiated in the core that can result as time passes in progressive damage to various metallic reactor components.

The nature of the thermal transient has been analyzed previously for other plants. The sketch below shows typical trends. Initial cooling (if any) brings all temperatures down. Upon interruption of forced cooling (IOFC), decay heat generated in the core tends to slowly heat up the fuel and graphite in the core. The primary coolant heats up, and naturally convects the heat to metallic components in the upper plenum. This transient continues until cooling is restored, whereupon downward flow is suddenly forced through the core, introducing hot gases into the lower plenum and cross ducts to the heat exchangers. This sudden temperature increase is quickly quelled by the reintroduced core cooling, and the temperature spike lasts only 1 to 2 hours. Once cooling is restored, subsequent component damage is averted.



Each branch on the event trees has been assigned to one of nine damage categories. Each damage category represents a degree of damage for which a certain amount of downtime is required to complete repairs. In general, the more extensive the damage, the longer the time required to repair. The transition from one damage category to the next is defined by the time when further damage is incurred.

The component damage limits of interest are shown in Table 7-1. These limits were compiled from several sources. The basic philosophy behind these limits is that no damage occurs as long as the physical changes in a component have a negligible impact on its ability to perform its intended function(s). The onset of impairment occurs when the physical changes in the component are not negligible.

Many of the limits in Table 7-1 are defined in Ref. 7-5. The first such limit is the damage limit, which corresponds to those conditions where the total deformation of a component exceeds the design limit by 1%. If the damage limit is exceeded, repairs may be required before normal plant operations can resume. The second, higher level of impairment is failure, which occurs when the critical safety limit is exceeded. The critical safety limit corresponds to those conditions where the total component deformation exceeds the design limit by 3%. If the critical safety limit is exceeded, interference with effective

TABLE 7-1
IMPAIRMENT LEVELS AND LIMITS

Component	Impairment Level	Impairment Limit	Source
Class A thermal barrier	Damage	1000°F for 10 hr[a]	Ref. 7-5
	Failure	1230°F for 1 hr[a]	Ref. 7-5
	Intermediate	1400°F for 1 hr[a]	Ref. 7-6
	Ablation	1500°F[b]	Ref. 7-7
Class B thermal barrier	Damage	1800°F for 10 hr[a]	Ref. 7-5
	Failure	2000°F for 1 hr[a]	Ref. 7-5
	Intermediate	2300°F for 1 hr[a]	Ref. 7-6
	Ablation	2300°F for 1 hr[a]	(c)
Region flow control orifices	Damage	2000°F for 1 hr	Ref. 7-5
	Failure	2400°F for 1 hr	Ref. 7-5
	Ablation	2700°F	Ref. 7-5
Plenum elements	Damage	2000°F for 1 hr	Ref. 7-5
	Failure	2300°F for 1 hr	Ref. 7-5
	Ablation	2600°F	Ref. 7-8
Control rods	Damage	2000°F for 1 hr	Ref. 7-5
	Failure	5100°F	Ref. 7-5
	Ablation	2500°F	Ref. 7-5
Fuel	Damage	3000°F	Ref. 7-5
	Failure	4300°F	Ref. 7-5
	Intermediate	1% particle failure[d]	Tech. Spec.
	Ablation	4700°F	Ref. 7-9
PCRV concrete[e]	Damage	200°F[f]	Ref. 7-10
	Failure	600°F[f]	Ref. 7-10
	Ablation	1800°F	Ref. 7-7
Liner[g]	Damage	200°F[f]	Ref. 7-10
	Failure	600°F[f]	Ref. 7-10
	Ablation	2000°F	Ref. 7-7

[a] The precise method to determine damage involves integrating time at temperature; however, these conditions have been found to reasonably approximate damage for our analyses.

[b] Could be up to 1750°F, depending on the failure mode used.

[c] Incipient melting point.

[d] A plant technical specification will call for fuel replacement when 1% of the fuel particles, averaged over the active core, have failed. Particle failures vary with temperature per Ref. 7-9, and core temperatures vary spatially.

[e] Bulk concrete temperatures.

[f] Based upon pressurized conditions.

[g] Effective temperature at concrete-liner interface.

core cooling may be incurred. It is generally assumed here that if either of these limits are exceeded, furnishing adequate assurances of plant safety to the NRC will be mandatory before normal operations can be resumed.

Recent experiments indicate that some of the limits cited in Ref. 7-5 are not completely representative, especially from the perspective of investment risk. To account for such situations, additional impairment levels are identified. The highest of the new impairment levels is ablation. Examples of ablation include melting the Incoloy-800 shrouds and spines in a control rod, and failing 100% of the particle coatings in a fuel block.

Where sufficient empirical data exist, impairment levels less severe than ablation but more severe than damage can be ascertained. These levels are defined as intermediate impairment. Intermediate impairment limits are not available for all components.

The time intervals that correspond to various damage categories are shown in Table 7-2 for various event sequences with different prior cooldown histories. These times were found in past risk assessments from thermal transient calculations which provided the times when component damage limits were exceeded. For this assessment, only limited additional thermal analyses were performed. The amount of core cooling available after reactor shutdown prior to interruption of forced cooling affects the rate of core heatup, and thus the times of component damage, because: (1) the core is cooler at the time of IOFC, so takes longer to heat up to the temperatures where damage is incurred; and (2) the decay heat generation rate decreases with time after reactor trip, so a heatup will progress more slowly if its onset is delayed.

The reactor fuel and core graphite heat up slowly during an IOFC. There is a large margin between normal operating temperatures and the temperatures at which these ceramic components may be damaged. In fact, metallic components will become damaged before ceramic components. The

TABLE 7-2

TIME INTERVALS AND ASSOCIATED DAMAGE CATEGORIES FOR INTERRUPTION OF CORE COOLING. DEPENDS ON PRIOR COOLDOWN HISTORY

Cooldown Before IOFC (hours)	Time Without Cooling (hours)	Damage Category
0	0 - 0.9	DC-9
	0.9 - 1.3	8
	1.3 - 3.2	7
	3.2 - 7	4
	7 - 8	3
	>8	1
5	0 - 6	DC-9
	6 - 6.7	8
	6.7 - 9.7	7
	9.7 - 11.1	5
	11.1 - 12.6	3
	12.6 - 17	2
	>17	1
5 - 10	0 - 6.5	DC-9
	6.5 - 7.3	8
	7.3 - 10.6	7
	10.6 - 12	5
	12 - 13.7	3
	13.7 - 18.5	2
	>18.5	1
10 - 100	0 - 10.9	DC-9
	10.9 - 11.4	8
	11.4 - 17.6	7
	17.6 - 20.7	5
	20.7 - 24.2	3
	24.2 - 35	2
	>35	1
100 - 1000	0 - 76.5	DC-9
	76.5 - 102	8
	102 - 132	7
	132 - 135	3
	135 - 150	2
	>150	1

Key: (see next page)

TABLE 7-2 (Continued)

Key:

Damage Category	Condition
9	No damage - minor delay
8	$\leq$1/8 control rods damaged
7	>1/8 control rods damaged; upper thermal barrier "failed" but can be shown to be acceptable.
5	Control rods ablate; upper thermal barrier "failed" but acceptable; plenum elements "damaged"
4	Control rods ablate; upper thermal barrier "failed" but acceptable; containment contaminated
3	Control rods ablate; plenum elements damaged; upper thermal barrier suffered intermediate impairment
2	Control rods ablate; plenum elements failed; upper thermal barrier suffered intermediate impairment; liner and PCRV "damaged" but acceptable
1	Unrestricted core heatup

first actual component damage will be to control rods suspended in the hottest regions of the core. The onset of this damage signals the transition from damage category DC-9 to category DC-8. This damage will occur at a time after the IOFC that depends on the amount of prior cooldown that occurred after reactor trip before IOFC.

As core temperatures continue to increase, more control rods become damaged, signaling the transition to category DC-7. Eventually the metallic cladding on some control rods begins to melt, and the damage level moves to category DC-5. Increasing core temperatures cause increased primary coolant temperatures in the upper plenum, such that limits on thermal barrier effectiveness are exceeded. The first limits to be exceeded are safety limits, and experimental evidence exists to indicate that these limits may be set too low and that exceeding the limits does not necessarily mean that the thermal barrier has suffered damage, much less that core cooling would be impaired. However, it is expected that if such limits were exceeded, some effort would be undertaken to demonstrate the capability of the thermal barrier to function satisfactorily in further use without repair.

As temperatures rise further, the plenum elements that sit on top of the upper reflector blocks may begin to sag, and orifice valves may suffer damage. Eventually, temperatures may increase to a point where thermal barrier damage is sustained such that repair is required before the plant would be allowed to resume normal operation. This would be represented as damage in category DC-3. In some cases temperatures may become high enough for thermal barrier coverplates to detach from their fixtures and fall away from the reactor vessel liner. This may also cause concern about any damage sustained by the liner or the PCRV concrete behind it due to the high temperatures to which they had been exposed, and damage would move into category DC-2. In about this time frame fuel particle failure may exceed the intermediate impairment limit.

The longer the time without forced cooling, the hotter the core gets, and the hotter the temperature spike when cooling is restored. The cross ducts and auxiliary heat exchanger are limited in the temperatures they can tolerate. At some point in time, the temperature spike may be such that it will cause damage to the heat exchangers such that core cooling cannot be maintained. If cooling is restored before this time, the accident can be mitigated without appreciable radioactivity release. This time has been referred to as the maximum time to restore cooling, or MTRC. Damage has been categorized for branches where cooling is restored before MTRC. If cooling is not restored before then, all subsequent damage is placed into one category of consequences, DC-1, representing the worst damage case. The time to repair DC-1 damage is assumed to be limited to the time to build a replacement power source.

Detailed analyses have not been performed for the 2240 MW(t) SC/C to find the times when damage occurs. However, the MTRC has been calculated as a function of prior cooldown history. The relationship is shown in Fig. 7-1. From this figure, the MTRC can be found for various event sequences. It was assumed that the intermediate damage would progress in a manner similar to that calculated previously for the 1170 MW(t) plant. Thus, all times that represent the onset of new damage and delineate between damage categories were found by using the corresponding times from for the 1170 MW(t) plant and adjusting them by the ratio of the 2240 and the 1170 plant MTRCs.

In addition, it was found that the PCRV pressure relief valve is expected to open following an immediate IOFC but not for an IOFC that starts after a 5-hour rundown. This finding was used to discriminate between cases where containment contamination must be cleaned up versus cases that will not require decontamination of the containment, i.e., category DC-4 versus DC-5. It was also recognized that such a pressure relief will diminish the effects of natural convection heat transfer, causing regions outside the core to heat up more slowly. Note that the

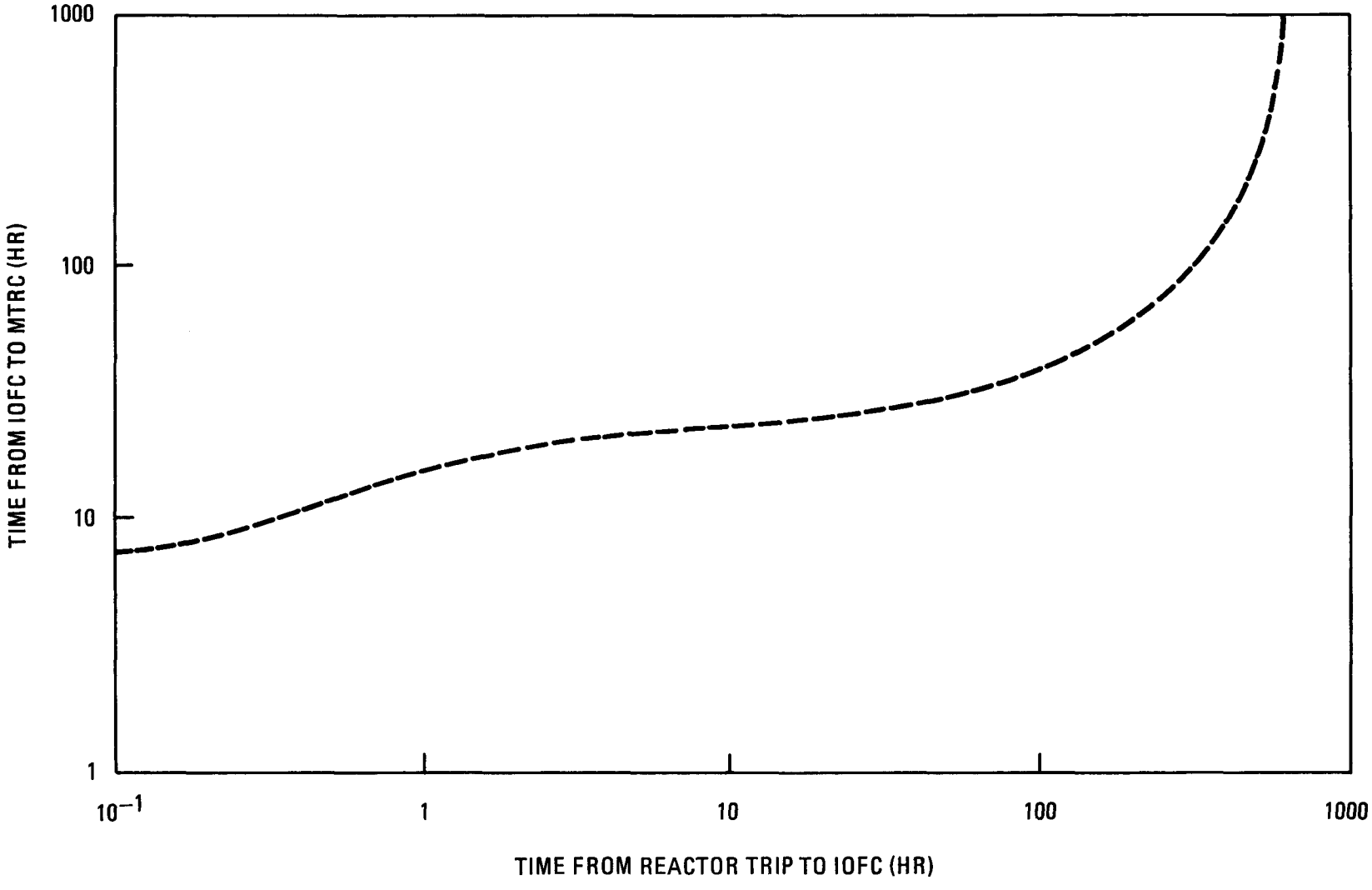


Fig. 7-1. Maximum time to restore cooling after an IOFC, as a function of the cooldown period prior to IOFC after reactor shutdown

rapid injection of helium into the reactor containment building during PCRV depressurization does not cause significant containment pressure loading.

7.2.2. Interruption of Liner Cooling

When liner cooling is interrupted, the expected response is a reactor trip and cooldown on main loops at a reduced level of helium flow. Concrete adjacent to the cavity liner is heated through the thermal barrier insulation by the initially hot helium, especially in the lower plenum. However, due to the continuously decreasing helium temperature under the shutdown mode of cooling, the rising concrete temperature would reach a maximum, then slowly decrease with the helium temperature. As long as the reactor can be shutdown within 30 minutes of the loss of liner cooling, no concrete damage will result.

Rarely is an interruption of liner cooling accompanied by an interruption of core cooling. If it is, then the liner and concrete temperatures would continue to increase with any increase in helium temperature, until core and/or liner cooling was restored. The concrete temperature decreases rapidly with distance from the liner, and elevated temperatures will be concentrated in the first few inches of concrete next to the liner, spreading away from it slowly with time.

No thermal calculation has been performed for the 2240 MW(t) plant for this transient. A typical calculation for a 3000 MW(t) plant showed that a maximum liner temperature of 375°F at the concrete-liner interface in the bottom plenum side wall was reached after about 2 hours without liner cooling. Because the 2240 MW(t) plant has a lower core outlet temperature, lower power, and lower power density, the transient liner temperature will remain below that of the 3000 MW(t) plant. The concrete temperatures will be lower than the liner temperature. From the ASME Boiler and Pressure Vessel Code (Ref. 7-10), the severe environmental limit for bulk concrete is 270°F, and the extreme environmental limit is 400°F.

Two damage categories have been defined. The onset of these categories is triggered when temperature limits are exceeded. The times when the appropriate damage limits are exceeded depend on the history of the event prior to the loss of liner and core cooling. Table 7-3 shows the time intervals that were used for various cases of prior cooldown.

7.2.3. Graphite Fuel Element Damage

The functions of the graphite fuel elements are to contain fuel and burnable poison pins, provide structural support, bear the dynamic and static loads from coolant flow, maintain alignment of coolant and control poison channels, and accommodate easy removal and replacement by the fuel handling machine.

The fuel elements are expected to perform the above-mentioned functions during normal operation and under expected transient, shutdown, and seismic loading conditions. A failure to perform these intended functions can result in plant downtime and thus investment risk. Failure to perform could result from damage of fuel elements by three important sources of loads: thermal gradients, irradiation induced dimensional changes, and earthquakes. During normal operation, the fuel elements are subject to both thermal and irradiation induced strains. The high creep rate during operation will cause the equivalent of a reversed thermal gradient and therefore resultant high stresses at shutdown. The fuel blocks are subjected to dynamic loads during seismic events.

In the graphite structural fragility model described in Section 6.3.5, the damage condition is divided into four discrete categories: (1) a no damage range, (2) a micro-cracking range which is characterized by no visible structural cracks and no significant loss of structural integrity, (3) a macrocracking range which is characterized by visible but limited cracks involving no element fracture and no compromise of element functional integrity, (4) an offset shear damage range characterized by longitudinal shearing fracture patterns which begin to

TABLE 7-3
TIMES WHEN CONCRETE DAMAGE LIMITS ARE EXCEEDED
FOLLOWING LOSS OF LINER AND CORE COOLING

Prior Cooldown[a] (hours)	Time After Which Consequence Category Applies (hours)	
	LC-2	LC-1
0	0.5	2
0-10[b]	2	4.5
10-100[b]	4	9

[a] Time between reactor shutdown and loss of liner cooling.

[b] Core cooling lost at same time as liner cooling.

Key:

Category	Condition
LC-2	Severe environmental limit exceeded. No repair required.
LC-1	Extreme environmental limit exceeded. PCRV concrete repair required.

compromise the element functional integrity, and by rubbling of the element into multiple fracture segments (along axial and horizontal shear planes) causing extensive structural failure of the block.

Only category 4, offset shear damage of the control fuel elements during a seismic event, represents a true potential investment risk. Normal operational and shutdown stresses are inadequate to cause offset shear, particularly due to stress relief mechanisms which have been discussed previously in Section 6.3.5. In all likelihood, the damage would be discovered during a refueling outage. All other damage categories are undetectable during the normal reactor operation, maintenance, and refueling activities.

7.2.4. Primary Coolant Leaks

Primary coolant leaks out of the PCRV to the reactor containment building in and of themselves do not interrupt power operation. Once a leak is discovered, depending on its size and therefore leak rate, the reactor may be shut down and cooling continued. The probability of a simultaneous failure in the redundant cooling system is negligibly low. Therefore, incremental fuel particle failure subsequent to the event does not occur.

Three PC categories have been identified as investment risk contributors. PC-1 involves a large leak of primary coolant through a PCRV penetration rupture greater than 0.6 in^2. The leak is detected by pressure monitors in the RCB or by low PCRV pressure. The reactor trips automatically or is manually shut down. The operator begins to pump primary coolant helium to storage, but more than 75% of the primary coolant and circulating activity escape from the PCRV into the reactor containment building. There is also a potential for liftoff and release of activity previously plated out onto primary circuit surfaces. The RCB is isolated; containment building pressure increases but remains below the 60 psig design pressure. (The margin depends on the actual

leak size.) Thus no structural damage occurs. Most of the activity is retained in the RCB, via either the containment cleanup system, gravitational settling of particulates, or plateout. Settled or plated out radionuclides would be cleaned from containment building surfaces in order to diminish the impact they might have on operating crews in the form of occupational health effects.

A primary coolant leak in category PC-2 involves the release of about 30% of the primary coolant and circulating activity from the PCRV to the containment through a PCRV penetration or instrument line leak. The remainder is pumped to storage after the leak has been detected by radiation monitors in the RCB and an orderly plant shutdown has been conducted. The RCB is isolated so that gaseous as well as particulate fission products are not released to the atmosphere. Consequently, some RCB surfaces may need to be cleaned of radionuclides that settle or plate onto them.

A primary coolant leak in category PC-3 involves the release of less than 10% of the primary coolant and circulating activity from the PCRV to the containment through a small PCRV penetration or instrument line leak. In all other respects, it is similar to a leak in category PC-2.

7.2.5. Steam Generator Transients

As mentioned in Section 6.3.7, none of the steam generator transients considered in this assessment was found to dominate the investment risk envelope of the 2240 MW(t) SC/C design. The consequence considerations leading to this conclusion are contained in the following two subsections.

In this assessment dry steam generators were considered as subject to rapid heating and possible damage.

7.2.5.1. Steam Generator Thermal Shock. If as a result of any of the events described below a steam generator inventory of water is lost and the helium circulator in that loop fails to trip, the helium circulator speed controller (Fig. 6-16) will attempt to run the circulator speed to zero based on its inputs of feed flow and rising steam temperature. However, as is common to most motor speed controllers, it is not possible for the circulator speed control to reduce circulator speed to a stop. From Ref. 7-11 it is estimated that following a loss of inventory the circulator speed is rapidly reduced to the minimum attainable circulator speed of approximately 10% of full speed.

For inventory losses due to spurious valve openings and feedwater line ruptures the plant is designed to recover and continue operating on three loops. Continued operation of the remaining loop circulators at 50% speed or above assures sufficient back pressure to shut the affected loop isolation valve and the transient is terminated.

In the case of an inventory loss caused by a steam generator leak or if the plant control system is unable to maintain three-loop operation following a single loop upset described above, a reactor trip is initiated and cooling is reduced to approximately 15%. With four circulators operating at or near their low speed limits, hot helium continues to flow through the dry steam generator and a rapid heatup of the tubes as depicted in Fig. 7-2 ensues. However, comparing these temperatures against Table 7-4 reveals that design temperatures of the steam generator have not been exceeded and no damage is expected.

7.2.5.2. Decontamination of Fallout After an SG-2 Accident. The steam generator release category SG-2 involves a large steam generator leak with dump to atmosphere. The redundant dump valves fail to reclose and therefore primary coolant, graphite oxidation products, and fuel hydrolysis activity follow the dumped steam generator water inventory as it is vented to atmosphere.

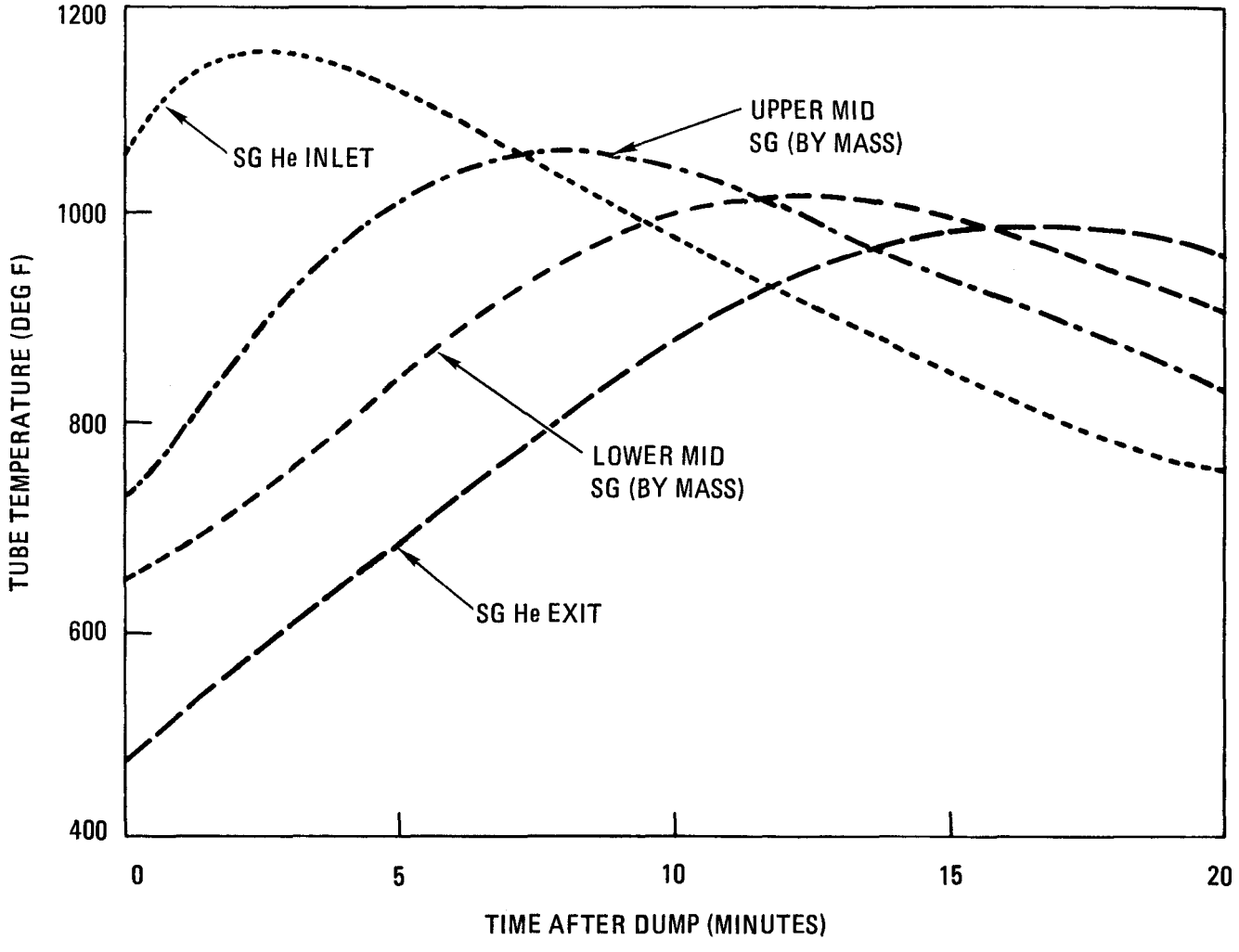


Fig. 7-2. Steam generator temperature profile during dry heat-up when circulator fails to trip but runs down to 15% speed

TABLE 7-4
STEAM GENERATOR TEMPERATURE LIMITS

Component	Safety Limit	Design Safety Limit	Function
Steam Generator:			
Helical bundle support plates	1200°F	1000°F[(a)]	Protect energy transfer capability and control release of radionuclides from primary pressure boundary
Evaporator	1200°F	935°F[(a)]	
Bimetallic weld	1200°F	950°F[(a)]	
Superheater	1400°F	1185°F[(a)]	
Superheater support	1400°F	1180°F	

[(a)]These values are normal design transient values; therefore, actual design safety limits are expected to be greater than these values.

This accident was simulated using the CRAC code for the Pt. Arthur site. The results showed that the fallout levels on-site were low so that no land interdiction or decontamination is required. A limited interdiction of milk is predicted if there are any grazing milk animals pastured within 1.5 miles of the plant. No interdiction of crops is predicted.

Some particulate and iodine activities would be expected to deposit in the dump system piping. This would mainly consist of Rb-88, I-131, I-133, Sr-90, Cs-134, Cs-137, Ba/La-140, and Te-132 which decays to I-132. The iodines and Rb would all decay to negligible levels within about two months leaving the longer lived Sr-90, Cs-134, Cs-137, and Ba/La nuclides. Of the iodines, only I-131 and I-132 (from Te-132) would last more than a few days. After a few days, the activities in the dump system piping could be flushed out with cleaning solutions. Some activity would also remain in the steam generator on the steam side. This could be cleaned after repairing the leaking tube by circulating water through the steam generator to the condensate demineralizer and polisher where the remaining long lived strontium and cesium would be removed. The resins from this operation would have more activity than from normal operation, so that fixation on the resins and disposal as radioactive waste would probably be required.

7.2.6. Seismic Events

To determine the consequences of a given seismic event with a given peak ground acceleration, fragility data (or functions) are required. Since insufficient fragility data exist for the 2240 MW(t) HTGR-SC/C plant, it is postulated for this scoping assessment that the HTGR plant sensitivity to seismic damage is the same as the Zion plant. This, of course, is a very gross assumption, but it is conservative (i.e., higher risk) because the Zion plant is designed for a safe shutdown earthquake (SSE) of 0.17 g peak acceleration whereas the HTGR-SC/C is designed for 0.30 g. Nonetheless, seismic response functions for equipment and structures were assumed to be identical to those of the Zion plant

(Ref. 7-3), except for nonseismic category I structure response, which was taken from a seismic study on earthquake resistant design (Ref. 7-12).

Structural capacity or fragility was assumed to be a lognormal probability distribution as a function of ground acceleration. Logarithmic standard deviation (β) and mean (also median) are used to determine failure probabilities for a given ground motion. To facilitate the examination of equipment and structural fragility, four seismic structural fragility classes are established. Table 7-5 gives the plant structural fragility classes and the acceleration levels that cause damage for each class. A conservative scoping philosophy was adopted for all seismic structural fragility classes. The fragility for each class was taken to be equal to that of the least earthquake resistant structure or component within that class.

Seismic structural fragility class 4 represents nonseismic category I structures which are assumed to be built to the uniform building code for zone 3 (as was done for Fort St. Vrain). Consequently, the design basis is approximately 0.08 g ground acceleration. However, based on Ref. 7-12, a conservative safety factor ~6 is added. The resulting median ground acceleration capacity for these structures is 0.48 g. The distribution for ground acceleration capacity is expressed in Ref. 7-12 as a logarithmic standard deviation, β, equal to 0.52. It was assumed that all equipment internal to these structures also fails with a probability of unity given that the structures fail.

Seismic structural fragility class 3 represents category I structures which are built to withstand Safe Shutdown Earthquakes (earthquakes in excess of 0.3 g ground acceleration capacity for an HTGR). The mean ground acceleration capacity was taken to be 0.63 g, which is based upon the Zion service water pump fragility, and the logarithmic standard deviation was assumed to be 0.39 from Ref. 7-3. All equipment internal to these structures was assumed to fail with a probability of unity given that the structures fail.

TABLE 7-5
SEISMIC PLANT FRAGILITY CLASSES AND ASSOCIATED GROUND ACCELERATION

Structural Fragility Class	Description (Least Earthquake Resistant Structure)	Median Ground Acceleration Capacity (g)	Logrithmic[(a)] Standard Deviation (β)
4	Nonseismic category I structural failures (non-safety class structures and buildings)	0.48	0.52
3	Category I structural failures	0.63	0.39
2	Equipment failure (except switchyards) (includes transformers, piping, etc.)	1.40	0.60
1	Switchyard gear failures	0.20	0.32

(a) $\beta = \ln \sigma_g$

Seismic structural fragility class 2 represents all equipment failures (except switchyard gear) and is characterized by the fragility of service water system piping and a 4160 volt transformer. Their mean ground acceleration capacity is 1.40 g, and their logarithmic standard deviation is 0.60 (Ref. 7-3).

Seismic structural fragility class 1 represents switchyard gear and is governed by offsite power ceramic insulators with a mean ground acceleration capacity of 0.20 g and a logarithmic standard deviation of 0.32 (Ref. 7-3).

7.2.7. Turbogenerator Failure

Damage categories due to turbomachine failure are based on actual failures in the power generation industry. The consequence of each failure is related to the extent of turbine damage. Turbomachine damage has spanned a wide range. Therefore, three categories of damage were chosen.

Damage category 3 consists of failure of from one blade up to a row of blades, or several blades in different rows. Category 3 is characterized by events in which a turbine at operating speed makes an audible bang followed by a noticeable increase in the machine imbalance which may exceed the shutdown level. Usually the operator shuts the machine down for dismantling and inspection. During the slowdown, vibration readings may increase significantly as the machine goes through critical speeds. Blade fragments are usually contained within the machine housing, although in one observed case the exhausted blade caused damage to the condenser. The consequence of this failure type is a turbine trip shutdown with little damage beyond the turbine machine itself. A single blade may be found several stages beyond the failure point and in most cases appears to cause little damage with the exception of nicking several subsequent blades.

Turbomachine damage category 2 includes cases of damage where multiple rows of blades, shrouds, or disc rims fail. In this category faults external to the turbomachine may result in the conditions which leads to water or material ingestion, or prevent machine shutdown given a trip signal (i.e., generator motoring). In these cases machine damage may occur over several minutes while the operator is trying to shut the machine down before it is further damaged as a result of excessive vibration. This damage category is characterized by several rows of blades separating at operating speed.

Damage category 1 includes catastrophic events such as disc and machine housing failures. These failures may result in missiles being thrown from the machine. Three basic failure types are described in the catastrophic failure experience base. These are generator failures at normal speed, turbine failures at normal speed, and machine overspeed failures.

The most representative overspeed failure occurred at Uskmouth in a 60 MW(e) turbine generator set. (See Ref. 7-13.) A loss of generator load occurred and the steam admission valve failed to close, allowing the turbine to speed up for a period of time lasting between 8 and 13 seconds. Based on metallurgical measurements of the distorted metal discs, the speed exceeded 170% and one disc separated at 163%. Assuming that the constant rate of speed increase was approximately 7%/sec and the measurements of the material stresses after failure are true, then the breakup must have occurred between 163 to 170% speed. If the speed changed at the same rate during the entire incident, the breakup time for the low pressure section was at least one second. Fortunately, the vibration of the breakup caused the admission valve to close and stop the steam flow to the damaged unit. This allowed the five other units at the station to remain on line without interruption of the steam supply.

Turbine failures at or near operating speed have also occurred; two similar failures are representative of the turbine failures in this category. At Gallatin, Tennessee, nine intermediate pressure (IP) section discs separated and all but the last low pressure (LP) disc were ejected through the casing. In the last stage, LP blades were knocked off making the disc look like a large spur gear. At Hinkley Point, three of eight IP discs separated in an estimated three shaft revolutions causing the shaft to break in six places. The abrupt halt of the machine caused a fire in the bearing oil which ignited hydrogen leaking from the generator. Both units, designed with shrunk on discs, failed without warning to the operators.

Based on these observed category 1 turbine failures, a single disc can separate in approximately one shaft revolution. However, multiple disc failures appear to require additional time, ranging from one failure per shaft revolution to approximately 1 second for an entire section under severe overspeed conditions. The extreme vibration of the shaft and bearings causes additional damage. An abrupt halt to the machine results as rotational energy is quickly transferred into the deformation, melting and separating the remaining components.

Almost half of the reported catastrophic failures were initiated by generator failures which typically caused an abrupt halt to the machine as materials jammed the generator air gap. Such failures cause significantly less damage to the turbine than the blade or disc failure, but do contribute to the combined machine failure modes of abrupt halt or shaft break if the rapid change in kinetic energy cannot be converted into heat and deformation of material at the generator.

In the event of a turbogenerator failure, the nuclear portion of the plant will undergo a power reduction, but will suffer no damage.

7.2.8. Inadvertent RSS Insertion

Consequences of inadvertent insertion of a portion or all of the reserve shutdown system depend on the number of hoppers released and on the operating status of the plant at the time of the release. For the scoping study presented here, it is assumed that the minimum release is one bank of five hoppers. It is assumed that if the conditions exist for the release of one hopper, the full bank of five hoppers are released. This is conservative because the reactor will be shut down to remove the RSS balls for all cases except the release of less than one full bank of hoppers.

Different failure modes exist depending on plant status. The important modes are illustrated in Fig. 6-20. Most failure modes involve the release of one bank of RSS hoppers. The exception is a common mode failure, such as when an operator does not properly follow the procedure for electrical surveillance and inadvertently releases all the hopper banks.

7.3. EVENT CONSEQUENCES

The net costs to a utility owner of an HTGR-SC/C following the events described above have been evaluated and are presented here. Much of the costs are attributable to plant downtime or loss of power production capacity. Therefore, an estimate has been made, for each category of damage, of the time that would be required to repair all damage and return the plant to operation.

7.3.1. Interrupted Core Cooling

The plant downtime required to return the plant to operation after an interruption of forced cooling is shown in Table 7-6 for the damage categories DC-1 through DC-9. This table shows median downtime estimates and upper and lower bounds on the downtime, which can be interpreted as 5% and 95% confidence bounds.

TABLE 7-6
PLANT DOWNTIME TO REPAIR DAMAGE FOLLOWING IOFC

Damage Category	Condition	Downtime, Months		
		Lower Bound	Median	Upper Bound
DC-9	No damage - minor delay	3 days	2 weeks	6 weeks
DC-8	$\leq$1/8 control rods damaged	2 weeks	2	4
DC-7	>1/8 control rods damaged; upper thermal barrier "failed" but can be shown to be acceptable	4	16	26
DC-5	Control rods ablate; upper thermal barrier "failed" but acceptable; plenum elements "damaged"	15	26	37
DC-4	Control rods ablate; upper thermal barrier "failed" but acceptable; containment contaminated	17	30	45
DC-3	Control rods ablate; plenum elements damaged; upper thermal barrier suffered intermediate impairment	17	30	45
DC-2	Control rods ablate; plenum elements failed; upper thermal barrier suffered intermediate impairment; liner and PCRV damaged but acceptable	19	36	59
DC-1	Unrestricted core heatup	72	96	144

The time required to assess damage, perform repairs and return to operation has been estimated based on engineering judgment. Designers of damaged equipment were interviewed for their estimates of procurement and replacement times. Details of the estimated "critical path" times required are shown in Table 7-7 for the damage categories arising from interruption of core cooling. Parallel activities are indicated where appropriate. Cumulative density functions of the downtime are shown in Figs. 7-3 and 7-4.

The potential dollar loss to the utility or owner of an HTGR that suffers an accident with consequences described above has been evaluated using a financial model that is described in detail in Appendix B. For each level or category of damage, the model was used to calculate unrecovered utility loss as a function of downtime, repair costs, insurance coverage, and rate adjustments. Thus, the net cost of replacement power and process steam while the plant is down, plus the cost of restoring the plant in excess of property insurance coverage, is the unrecovered utility loss. The unrecovered utility loss for each category of consequence due to interruption of core cooling is shown in Table 7-8. The cost of restoring the plant exceeds insurance coverage only for the most severe category, DC-1. Even for that case the costs of replacement power and process steam dominate the unrecovered utility loss.

7.3.2. Interruption of Liner Cooling

Two damage categories have been defined due to an interruption of liner cooling and are shown in Table 7-9. Category LC-2 involves the cases where the severe environmental limit is exceeded but no damage was actually done. Downtime of 3 months is estimated, during which time activities would focus on convincing regulatory bodies that further plant operation is safe. Category LC-1 includes cases where concrete damage occurs, or is suspected and must be repaired. This category is possible when the extreme environmental limit is exceeded. Downtime of just under 2 years is estimated to repair concrete behind the vessel

TABLE 7-7
DETAILED ESTIMATES OF TIME REQUIRED TO RETURN PLANT
TO OPERATION AFTER INTERRUPTION OF CORE COOLING

Repair Activities	Time Required, Months		
	Lower 5%	Median	Upper 95%
DC-9: No damage - minor delay			
Assure/check for no damage	1 day	5 days	2 weeks
Communicate with regulators	2 days	10 days	1
	3 days	2 weeks	6 weeks
DC-8: $\leq$1/8 control rods damaged			
Identify damaged control rods	5 days	3 weeks	6 weeks
Checkout and install spares	8 days	3 weeks	6 weeks
Communicate with regulators	1 day	2 weeks	1
	2 weeks	2	4
DC-7: >1/8 control rods damaged; upper thermal barrier (TB) failed but can be shown to be acceptable			
Identify damaged control rods	1 week	1	2
Procure replacements	2	12	18
Checkout and install replacements	1 week	1	2
Communicate with regulators on control rods	2 weeks	2	4
Evaluate damage to TB	2	6	18
Communicate with regulators on TB	2	6	8
(Do TB evaluation in parallel with control rod repair)	(3)	(12)	(26)
	4	16	26
DC-5: Control rods ablate; upper TB "failed" but acceptable; plenum elements "damaged"			
Identify damaged control rods	2 weeks	6 weeks	3
Procure replacement control rods	12	18	24
(Clean out melt mess in parallel)			
(Identify damaged plenum elements/ orifice valves, procure replacements in parallel with control rods)	--	--	--
Checkout and install replacements	6 weeks	4	6
Communicate with regulators	1	10 weeks	4
(Evaluate TB in parallel with control rod repairs)	--	--	--
	15	26	37

TABLE 7-7 (Continued)

Repair Activities	Time Required, Months		
	Lower 5%	Median	Upper 95%
DC-4: Control rods ablate; upper TB "failed" but acceptable; containment contaminated			
Await decay before decontaminating	1 week	1	3
Decontaminate	5 weeks	67 days	6
Plan, communicate with regulators	1	2	2
Identify damaged control rods	2 weeks	6 weeks	3
Procurement replacements (clean out melt mess in parallel)	12	18	24
(Do in parallel with second half of decontamination)	(3 weeks)	(1)	(3)
Checkout and install replacements	6 weeks	4	6
Communicate with regulators on control rods	1	10 weeks	4
(Evaluate TB in parallel with control rod repairs)	--	--	--
	17	30	45
DC-3: Control rods ablate; upper TB suffered intermediate impairment; plenum elements damaged			
Fix control rods and plenum elements per DC-5	15	26	37
Plan TB replacement	2	3	4
Fabricate new TB; remove old TB	4	8	12
Install new TB	5	8	15
(Fix TB in parallel with control rods and plenum elements)	(11)	(19)	(31)
Plan refueling structure repairs	--	2	4
Repair structure	--	3	6
(Do in parallel with TB plan and fabrication)	--	(5)	(10)
Reload fuel, restart	2	4	8
	17	30	45
DC-2: Control rods ablate; plenum elements failed; upper TB suffered intermediate impairment; liner and PCRV "damaged" but acceptable			
Plan TB replacement	2	3	4
Fabricate new TB; remove old TB	4	8	12
Assess liner/PCRV condition	2	4	6
Communicate with regulators	1	2	4

TABLE 7-7 (Continued)

Repair Activities	Time Required, Months		
	Lower 5%	Median	Upper 95%
Install new TB	5	8	15
Plan refueling structure repairs	1	2	4
Repair structure	3	4	7
(Do in parallel with TB plan and fabrication)	(4)	(6)	(11)
Identify damaged control rods and plenum elements/orifice valves, procure replacements, cleanout rod melt mess	12-1/2	19-1/2	27
(Do in parallel with TB plan and fabrication, liner assessment, communication with regulators, and TB installation)	(12-1/2)	(19-1/2)	27
Checkout and install replacements, reload fuel	3-1/2	8	14
Communicate with regulators	1	10 weeks	4
	19	36	59
DC-1: Uncontrolled core heatup Assume plant output is restored in time required to construct new plant	72	96	144

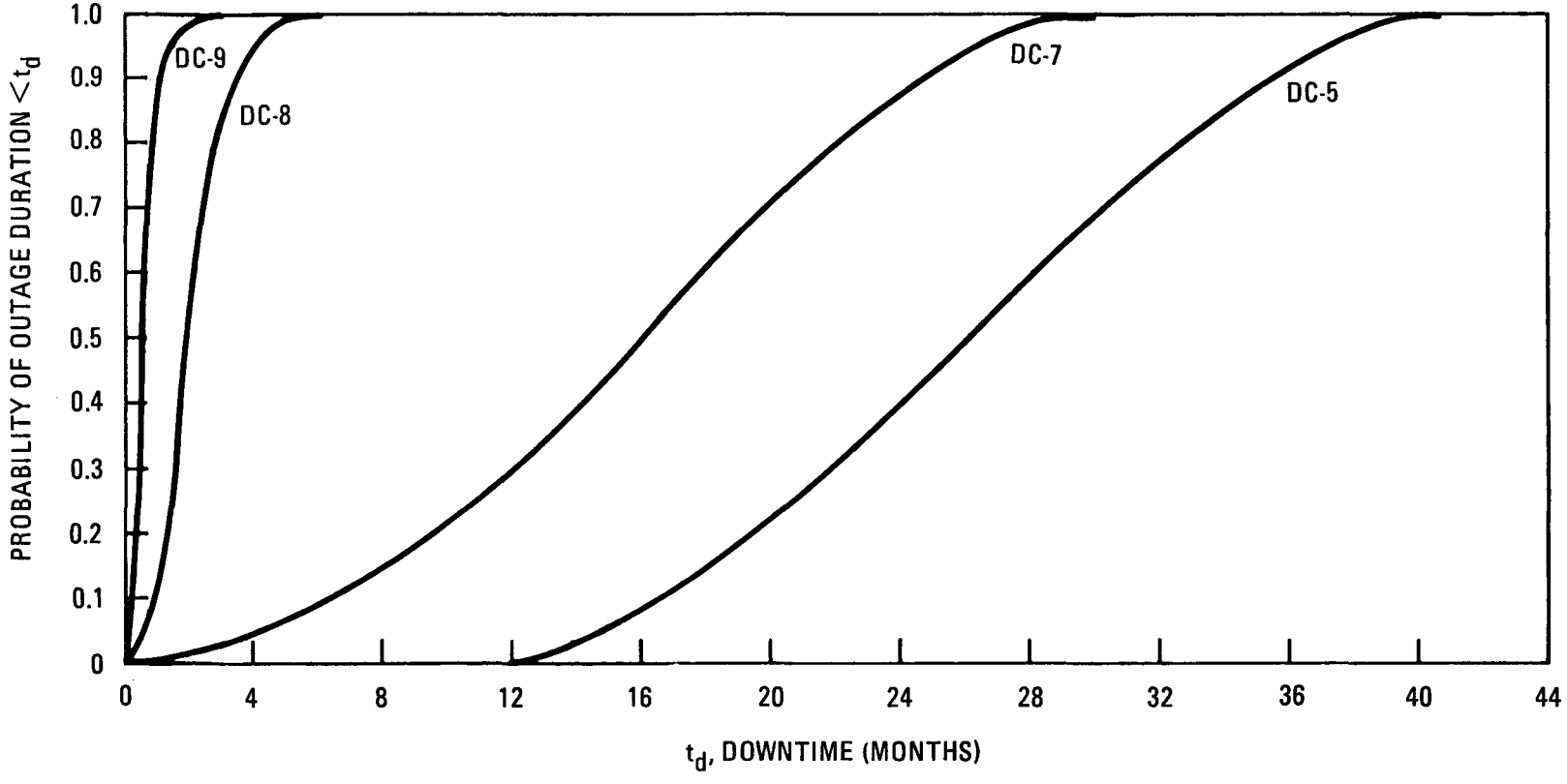


Fig. 7-3. Cumulative distributions for outage durations for interruption of forced cooling damage categories DC-5 thru DC-9

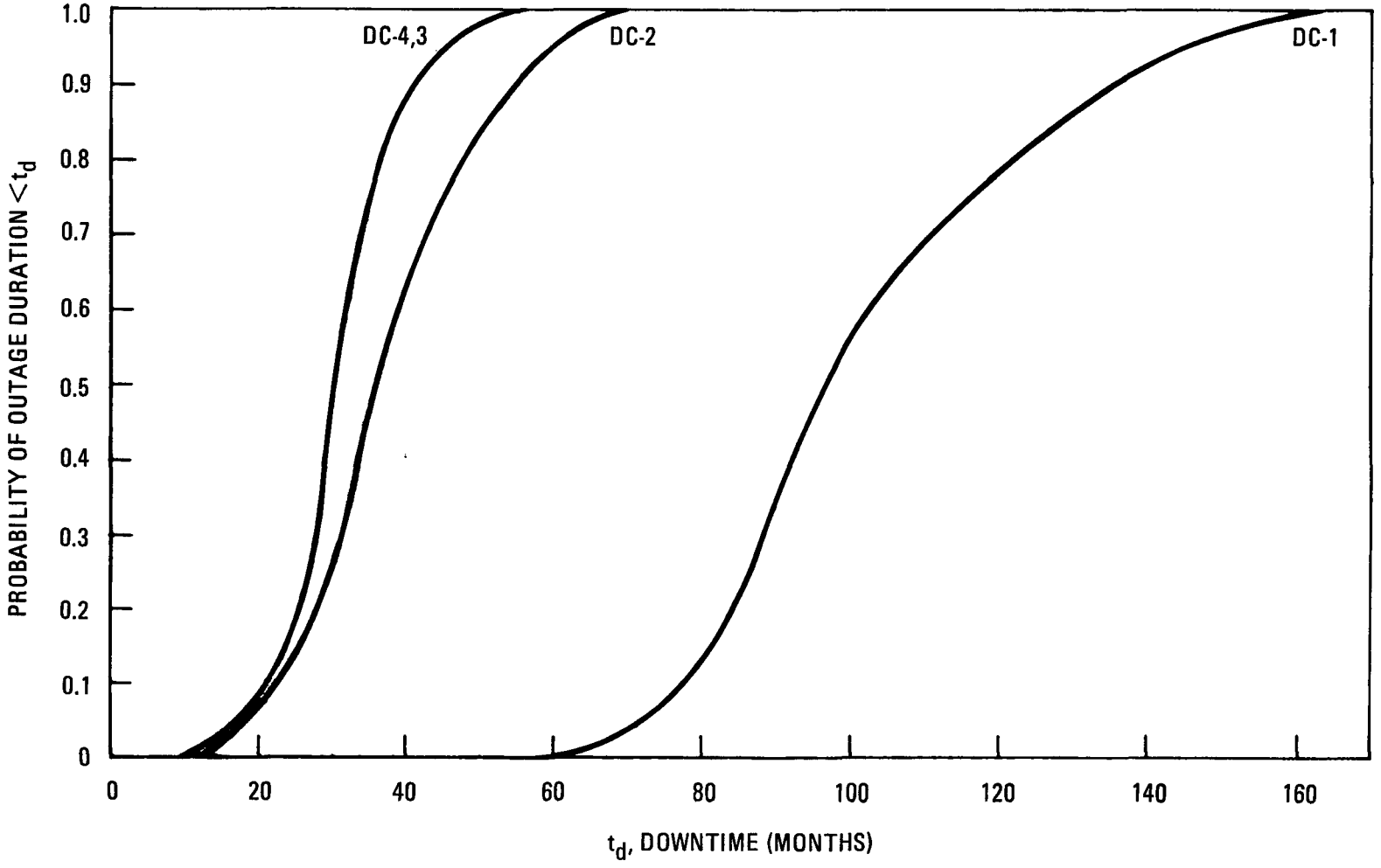


Fig. 7-4. Cumulative distributions for outage durations for interruption of forced cooling damage categories DC-1 thru DC-4

TABLE 7-8
MEAN UNRECOVERED UTILITY LOSS BY CONSEQUENCE CATEGORY
FOR INTERRUPTION OF CORE COOLING

Consequence Category	Decription	Loss ($ Million)	
		Median	Mean
DC-9	No damage - minor delay	11	14.7
DC-8	$\leq$1/8 control rods damaged	44	48.5
DC-7	>1/8 control rods damaged; upper thermal barrier (TB) "failed" but acceptable	330	328.0
DC-5	Control rods ablate; upper TB "failed" but acceptable; plenum elements damaged	540	546.0
DC-4	Control rods ablate; upper TB "failed" but acceptable; containment contaminated	620	642.0
DC-3	Control rods ablate; upper TB suffered intermediate impairment; plenum elements damaged	620	642.0
DC-2	Control rods ablate; plenum elements failed; upper TB suffered intermediate impairment; liner and PCRV damaged but acceptable	770	801.0
DC-1	Uncontrolled core heatup	2600	2700.0

TABLE 7-9
PLANT DOWNTIME AFTER INTERRUPTION OF LINER COOLING

Repair Activities	Time Required, Months		
	Lower 5%	Median	Upper 95%
LC-2: Severe environmental limit exceeded; PCRV concrete OK			
Evaluate PCRV concrete	3 weeks	3	12
LC-1: Extreme environmental limit exceeded; PCRV concrete needs repair			
Repair PCRV concrete, return plant to service (Possible half the time)	13.5	22	40
	or	or	or
Assume plant output is restored in time required to construct new plant (Possible half the time)	72	96	144

liner and return the plant to power. However, it is assumed that such repair is possible only half the time. Otherwise it is estimated that the plant must be replaced, with a median downtime of 8 years.

Figure 7-5 shows the cumulative density function for the downtime for loss of liner cooling category LC-1. The downtime for category LC-2 is assumed to be lognormally distributed.

The unrecovered utility cost due to the categories of damage described above has been assessed using the financial model described in Appendix B. These unrecovered costs are shown in Table 7-10 for the consequence categories due to interruption of liner cooling.

7.3.3. Graphite Fuel Element Damage

If one or more control elements experiences offset shear during a seismic event, it is anticipated that the breakage will remain undetected until the elements are scheduled for removal during refueling. This is because offset shear is not expected to interfere with control or power rod movement, increase core outlet temperature, or contribute to the circulating activity. Therefore, given that at least one offset control element shear occurs, the outage duration is the effective number of full power operating months lost due to discovering the breakage during a planned refueling.

An important consideration in assessing the outage duration is the Nuclear Regulatory Commission's (NRC) perception of the safety implications associated with the breakage, since the NRC could shut down the plant for an extended period. Two factors that will influence the NRC are:

1. The amount of allowable control element damage established in the plant license, and

2. The number of broken elements discovered.

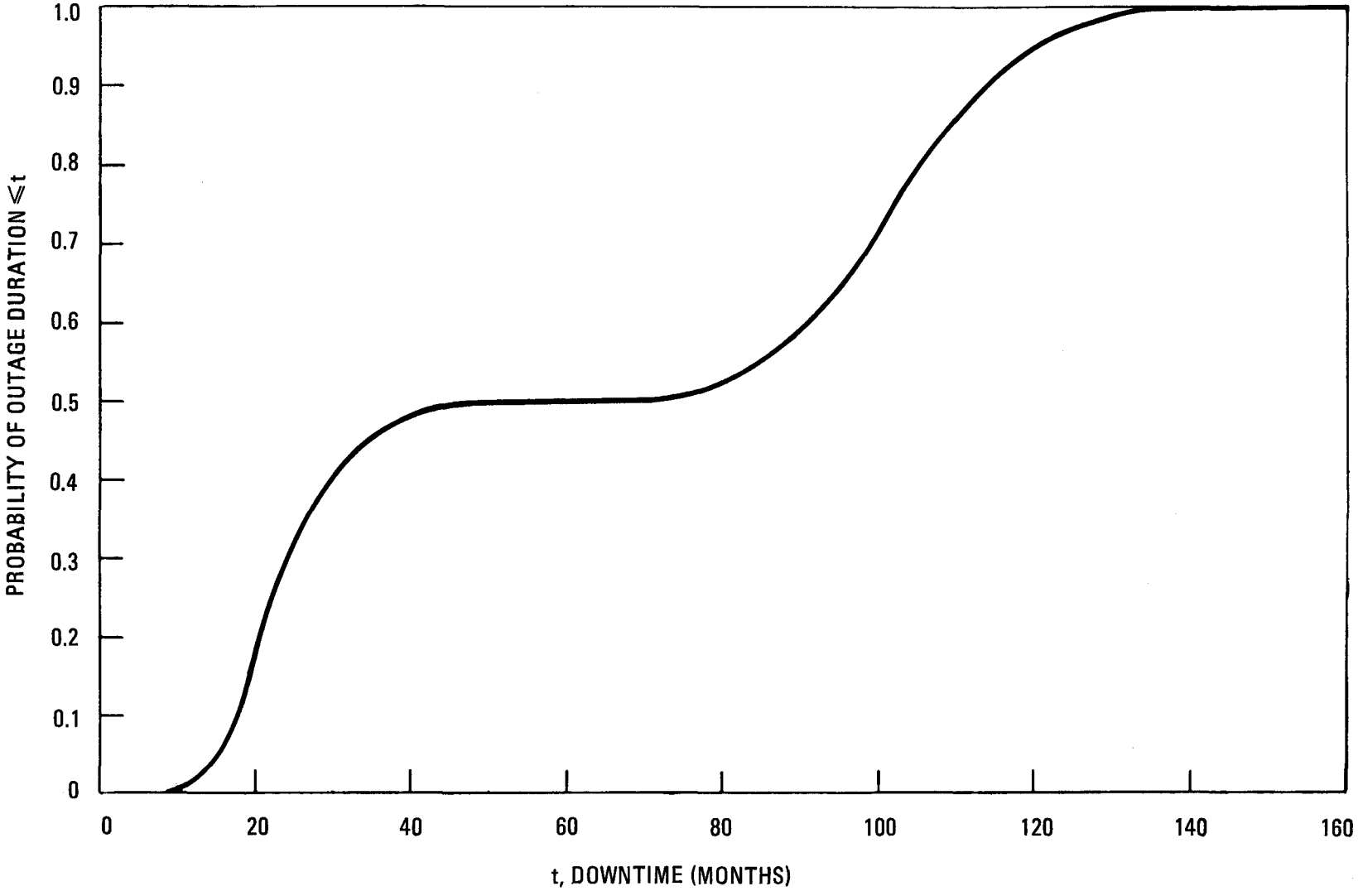


Fig. 7-5. Cumulative distribution for outage duration for loss of liner cooling consequence category LC-1

TABLE 7-10
MEAN UNRECOVERED UTILITY LOSS BY CONSEQUENCE CATEGORY
FOR INTERRUPTION OF LINER COOLING

Consequence Category	Description	Loss ($ Million)	
		Median	Mean
LC-2	Severe environmental limit exceeded; PCRV concrete shown OK	67	94
LC-1	Extreme environmental limit exceeded; PCRV concrete needs repair	1300	1590

The consensus is that allowable element damage would be limited to some macroscopic cracking, predicated in part upon recent events at Fort St. Vrain. Because of this recent Fort St. Vrain experience, the occurrence of macroscopic cracking is expected to contribute negligibly to plant investment risk. Therefore, the only true potential investment risk scenario involves the discovery of a small number of control elements with damage category 4 offset shears resulting from a low magnitude seismic event which would violate the licensing limits.

An initial attempt to quantify the outage scenario due to control element damage involved a literature search to see if a comparable scenario had occurred in a LWR. Since no similar scenarios were reported, it became necessary to employ Delphi techniques in order to estimate the outage duration.

The eight individuals surveyed were selected because of expertise in the areas of HTGR design and operation, graphite technology, and HTGR licensing.

The accident was explained to each respondent and they were asked to provide an interval estimate of the outage duration. Interval estimates were explicitly solicited to provide a measure of uncertainty. If a respondent offered more than one outage scenario they were asked to supply weighting factors indicative of the relative importance assigned to each scenario. Table 7-11 is a synopsis of the elicited responses.

These responses were then approximated by lognormal distributions. Where multiple responses were given, the distribution function for each response was multiplied by its weighting factor so that a single, normalized distribution function resulted for each respondent. Since there was no basis for favoring the opinion of one expert over another, one-eighth the sum of these distribution functions was then taken as the overall outage distribution function. The complementary cumulative outage distribution is shown in Fig. 7-6 as the conditional probability

TABLE 7-11
RESULTS OF THE OUTAGE DURATION SURVEY

Response Number	Outage Duration[a]	Weight
1-A	Plant shutdown between 1 and 12 months.	0.8
-B	Plant shutdown between 12 and 24 months.	0.2
2-A	Plant shutdown between 1 and 3 months.	0.8
-B	Plant shutdown between 1 and 3 months, followed by derated operation for 9 to 11 months at power levels between 50% and 75%.	0.2
3	Plant shutdown between 3 and 24 months, with a mean of ~6 months.	1.0
4-A	Plant shutdown between 9 and 12 months, followed by 24 months of testing at ~50% power, followed by permanent derating to 50% power.	0.5
-B	Plant shutdown between 9 and 12 months, followed by 30 to 36 months of testing at ~50% power, followed by permanent derating to 50% power.	0.25
4-C	Plant shutdown between 9 and 12 months, followed by 30 to 36 months of testing at ~50% power.	0.25
5	Plant shutdown between 8 and 9 months.	1.0
6	Plant shutdown between 3 and 12 months, with a median of ~6 months.	1.0
7	Plant shutdown for ~9 months, with an uncertainty factor between 2 and 3.	1.0
8-A	Plant shutdown between 0 and 3 months.	0.5
-B	Plant shutdown between 6 and 12 months.	0.5

[a]Except for responses 4-A and 4-B, the plant is returned to full power operation at the end of the outage scenario.

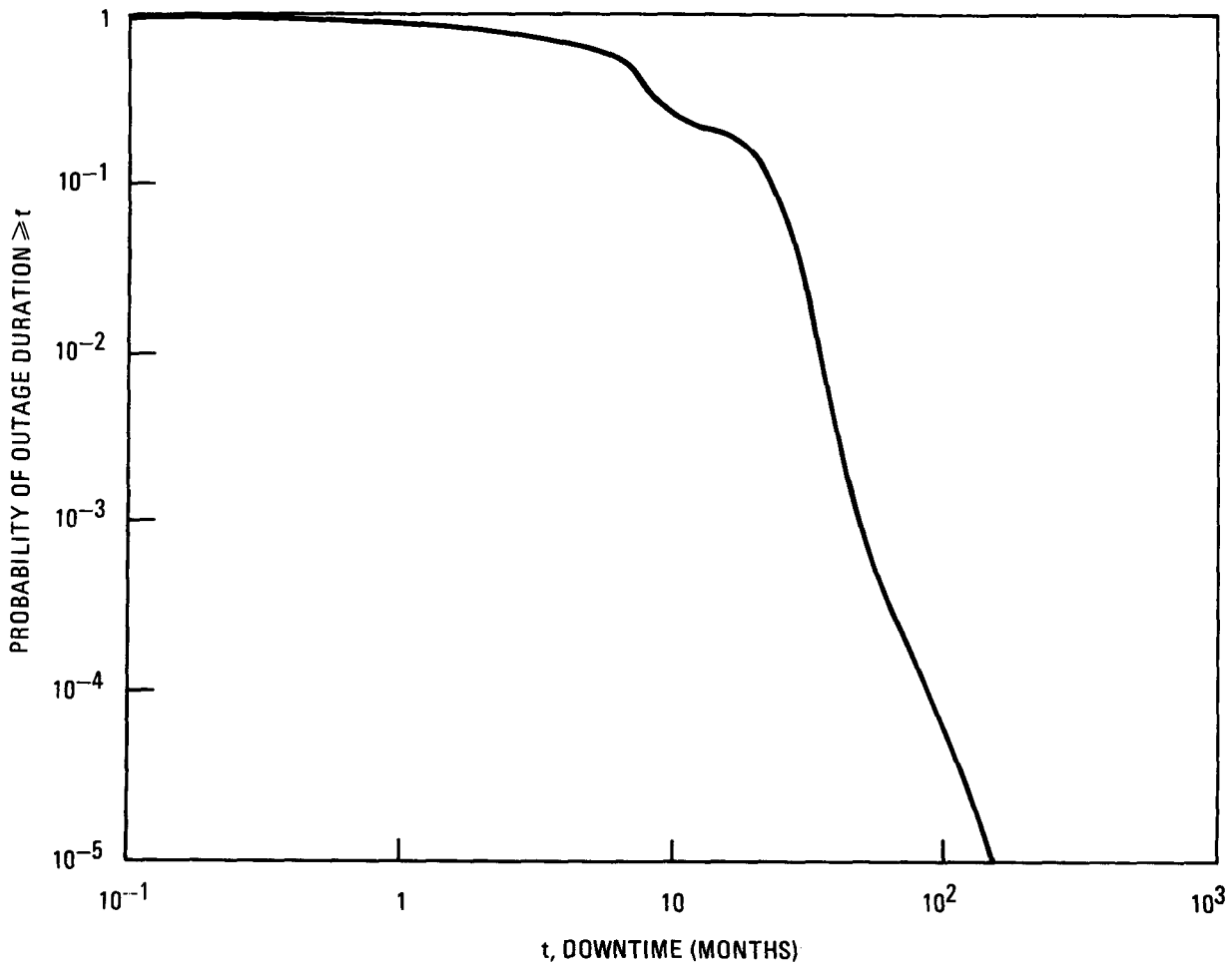


Fig. 7-6. Complementary cumulative distribution for outage duration due to fuel element cracking

that the plant outage duration exceeds t months given that a control element breakage has occurred.

The unrecovered dollar loss to the utility due to an offset shear failure of 1 to 3 control blocks (category FE-1) has been evaluated using the financial model described in Appendix B. The median loss was found to be $147 million, with a mean loss of $191 million.

7.3.4. Primary Coolant Leaks

An evaluation of the dose rate levels in the containment following a PC-2 type of leak shows that gaseous dose rate levels will initially hamper containment access. As shown in Fig. 7-7, dose rates in excess of 50 mr per hour will prevail in the containment for a week after a leak of 30% of the primary coolant inventory, unless the gases can be vented to the environment. The amount of radioactive gases to be vented is 3 orders of magnitude less than the amount that was vented from the Three Mile Island Unit II containment. Since the dose that would be received offsite would be much smaller than background if these radioactive gases were released from the containment, it is expected that a release would be delayed only long enough to gain regulatory approval, and perhaps to await favorable weather conditions. Otherwise, containment entry would be limited, and therefore repair and recovery would proceed slowly.

When the gaseous dose contributors had been dissipated, the leak would be repaired and containment surfaces would be cleaned to remove radioactive particulates that had settled by gravity. These particles are not expected to produce a limiting dose to workers, but it is expected that a detergent scrub would be used to prevent the reentrainment or scattering of these particles, and to minimize any occupational dose.

Table 7-12 shows details of the downtime estimated after a primary coolant leak. The nature of this downtime is illustrated in Fig. 7-8.

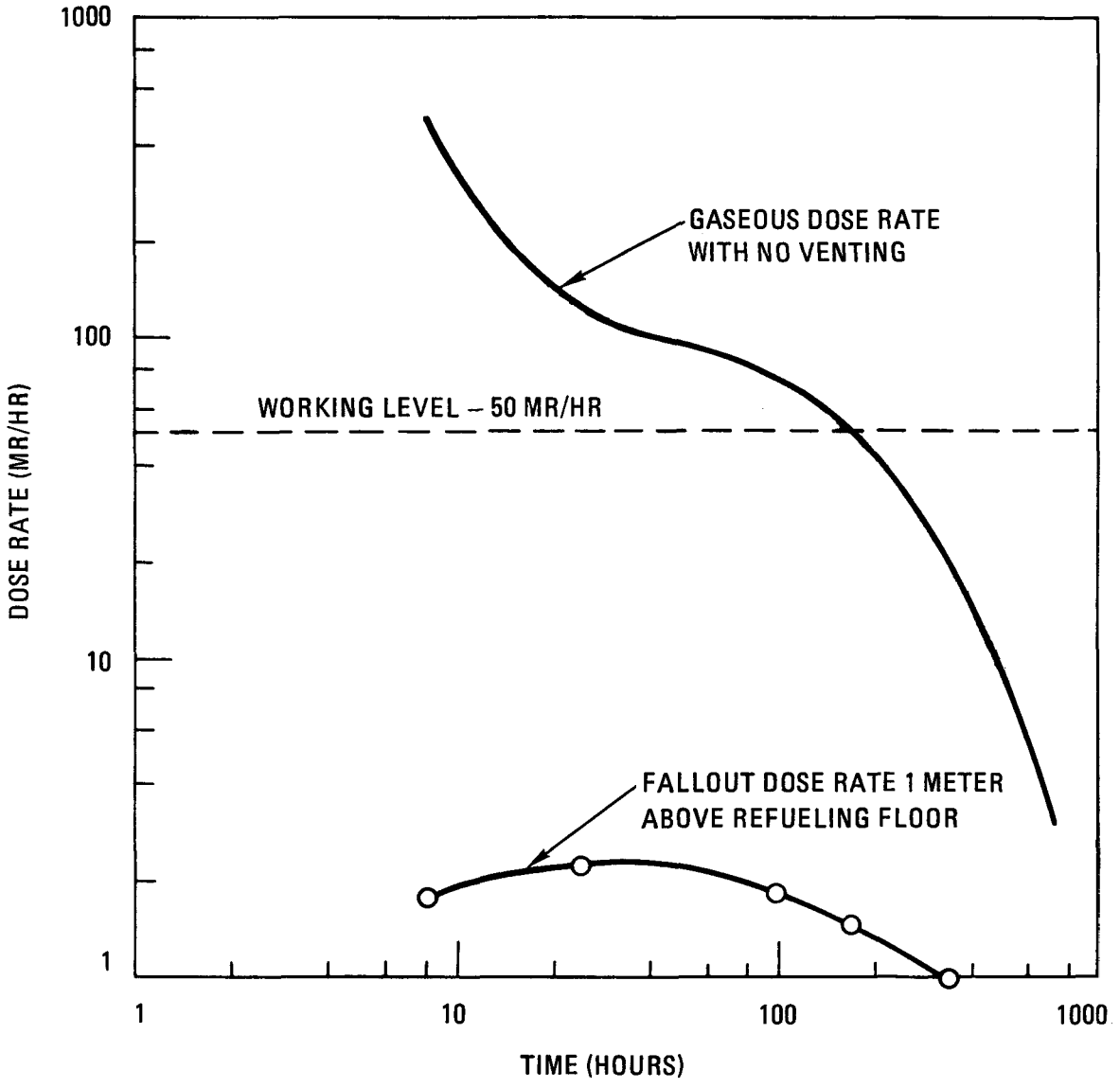
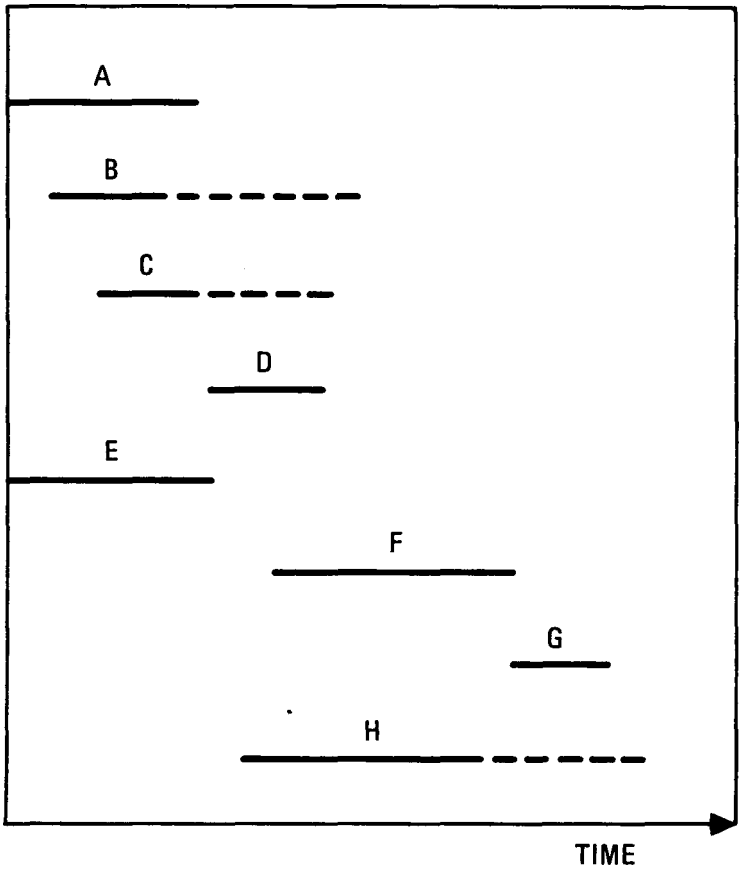


Fig. 7-7. Whole body gamma dose rate in containment after release from PCRV of 30% of circulating activity. 2240 MW(t) HTGR-SC/C gravitational setting only, no recirculating filters

TABLE 7-12
ESTIMATES OF TIME REQUIRED TO RETURN PLANT
TO OPERATION AFTER PRIMARY COOLANT LEAK

Repair Activities	Time Required, Days		
	Lower 5%	Median	Upper 95%
PC-3: 0.006 to 0.06 in^2 leak releases 4-20% He inventory			
Assess situation, await decay/venting,	1	2-1/2	6
ID cause, discuss with reg body	2	3	7
Refurbish/repair	1	4	14
Plan for cleanup, procure, train	2	4	7
Cleanup contamination	7	14	21
(Plan and clean in parallel with decay, refurbishment and discussions)	(4)	(9-1/2)	(27)
	9	18	28
PC-2: 0.06 to 0.6 in^2 leak releases 20-75% He inventory			
Assess situation, await decay/venting	2	6	16
ID cause, discuss with reg body	2	5	14
Refurbish/repair	2	7	30
Plan for cleanup, procure, train	3	7	14
Cleanup contamination	10	21	42
(Plan and clean in parallel with decay, refurb, and discussions)	(6)	(18)	(56)
	13	28	60
PC-1: 0.6 in^2 leak or greater releases 75-100% He inventory			
Assess situation, await decay/venting	12	15	31
ID cause, discuss with reg body	30	90	180
Refurbish/repair	7	21	90
Plan for cleanup, procure, train	5	10	20
Cleanup contamination	14	28	60
(Plan and clean in parallel with decay, refurb, and discussions)	(19)	(38)	(80)
	49	126	300



KEY TO ACTIVITIES:

A EVALUATE & PLAN CLEANUP & WASTE DISPOSAL
B PROCURE EQUIPMENT FOR CLEANUP, WASTE TREATMENT
C TRAIN PERSONNEL
D PERFORM CLEANUP, MODIFY PLANS AS NEEDED
E ALLOW FOR DECAY/VENTING
F REFURBISH EQUIPMENT AS NEEDED
G TEST EQUIPMENT, RETURN TO POWER
H PROCESS WASTES

Fig. 7-8. Typical activities required for return to power after a primary coolant leak and the relative times when each can be done

Some events can proceed in parallel, while others must be done in series with one another. Depending on the level of contamination in the containment, cleanup may be necessary before repair can proceed, or it may be done in parallel, or it may not be necessary at all. It has been determined for the 2240 MW(t) plant that working in the containment would not be done until the gaseous dose source was dissipated, either by venting or decay. Containment access would be allowed for the purpose of repairing the leak source in parallel with efforts to clean up surface contamination, which would deliver a low dose, but which should be removed promptly to minmize the spread of contamination and the small dose that would otherwise be incurred. Cumulative density functions of the downtime required to return the plant to power are shown for the primary coolant leak categories in Fig. 7-9. Downtime is dominated by cleanup of contamination if the leak is small and can be quickly fixed. However, if the leak is large, its repair may dominate the recovery efforts.

The unrecovered utility costs due to primary coolant leaks have been assessed using the financial model described in Appendix B. These costs are shown in Table 7-13 for consequence categories described above. The costs are dominated by the net cost of replacement power and process steam while the plant is down.

7.3.5. Steam Generator Transients

Since it was concluded in Section 7.2.5.1 that no damage results from the postulated steam generator thermal transients, there is no downtime or monetary consequence associated with those transients.

Downtime due to a steam generator leak with dump to atmosphere (SG-2) is likely to be driven by regulatory considerations. The NRC response to an SG-2 depressurization accident is uncertain and speculative. However, discussions with experts suggest that at the minimum there would be an investigation, analysis, reports, and a hearing into the accident. In addition, it is felt possible, but not likely that

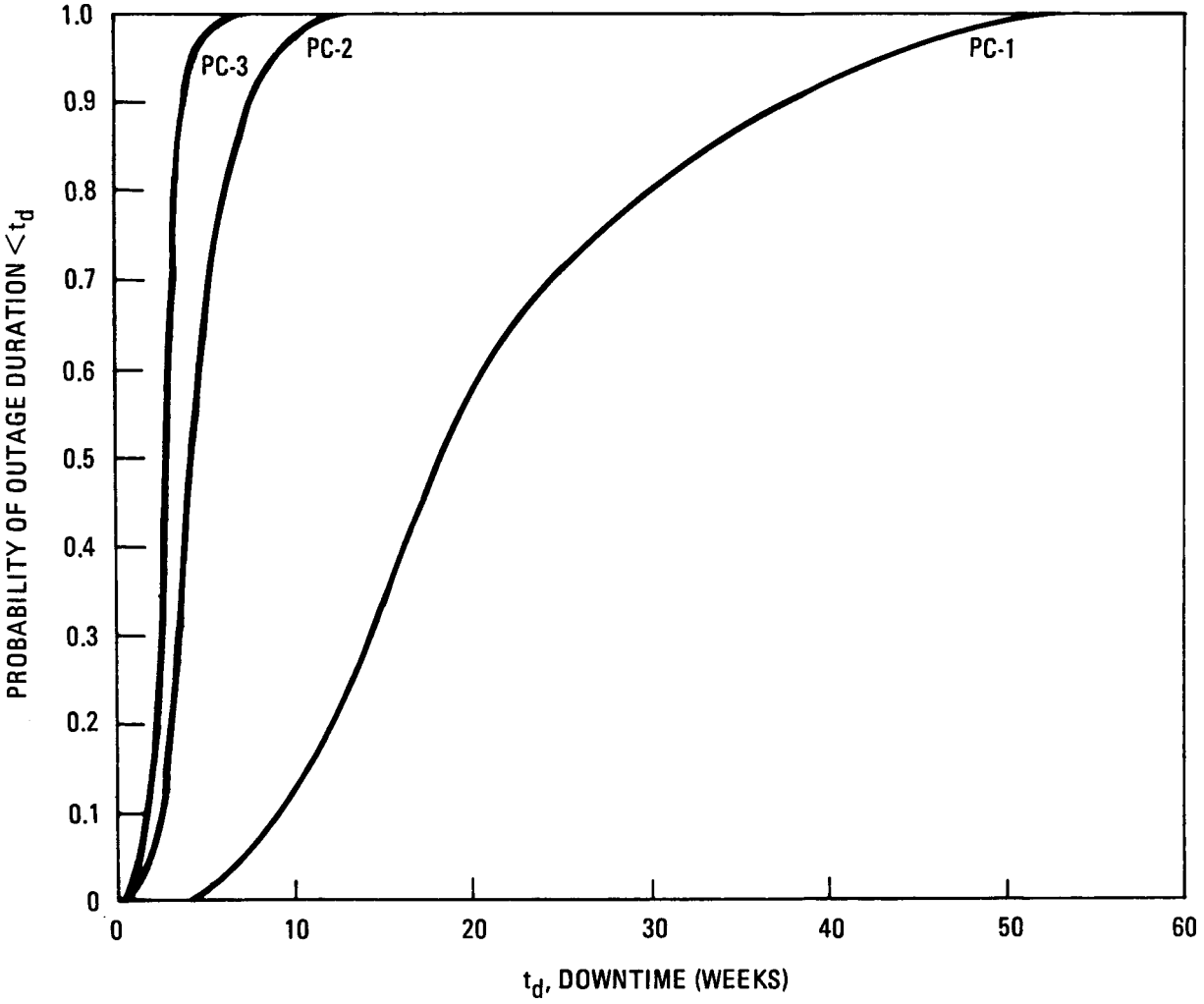


Fig. 7-9. Cumulative distributions for outage durations for primary coolant leaks

TABLE 7-13
MEAN UNRECOVERED UTILITY LOSS BY CONSEQUENCE CATEGORY
FOR PRIMARY COOLANT LEAKS

Consequence Category	Description	Loss ($ Million)	
		Median	Mean
PC-3	0.01 in^2 leak releases 4-20% helium	13	14
PC-2	0.1 in^2 leak releases 20-75% helium	21	23
PC-1	>0.6 in^2 leak releases 75-100% helium	94	106

backfit with dump tanks would be required. Modifications to the dump valve system were believed likely. The plant shutdown during these activities is estimated to be in the range of at least one month, but less than two years, with a mean value of 6 months. A cumulative density function of downtime following an SG-2 accident is shown in Fig. 7-10.

An SG-2 accident could be expected to exceed the consequences to the public and the utility of the Ginna steam generator leak accident in January 1982. In the Ginna accident, several steam generator tubes ruptured, releasing mainly some noble gases (about 90 Ci) and iodines in a short puff to the atmosphere. The plant was consequently shutdown for steam generator tube inspection and plugging to repair the leak. The shutdown lasted close to 4 months, with the utility electing to perform refueling in parallel slightly ahead of schedule along with some other routine maintenance during the outage. Approximately three orders of magnitude more activity, mainly noble gases, would be released in an SG-2 event compared to the Ginna occurrence.

In the FSV release of January 1978, some primary coolant leaked through the circulator buffer seals, eventually reached the reactor building, and was vented to the atmosphere before the seal could be reestablished. About 4 Ci of noble gases were released. In this case, the NRC required analyses of why the accident occurred, a failure modes and effects analysis for the helium circulator system, modifications for remote isolation of the helium dryers, increased surveillance requirements for the helium circulator system, and a commitment to split the two circulator loops which was performed at a later time. The outage lasted close to 2 months. This event released even less activity than the Ginna event, and would be expected to also be lower in consequence than an SG-2 event.

The median and mean costs to the utility due to an SG-2 event have been found, using the financial model of Appendix B, to be $133 million

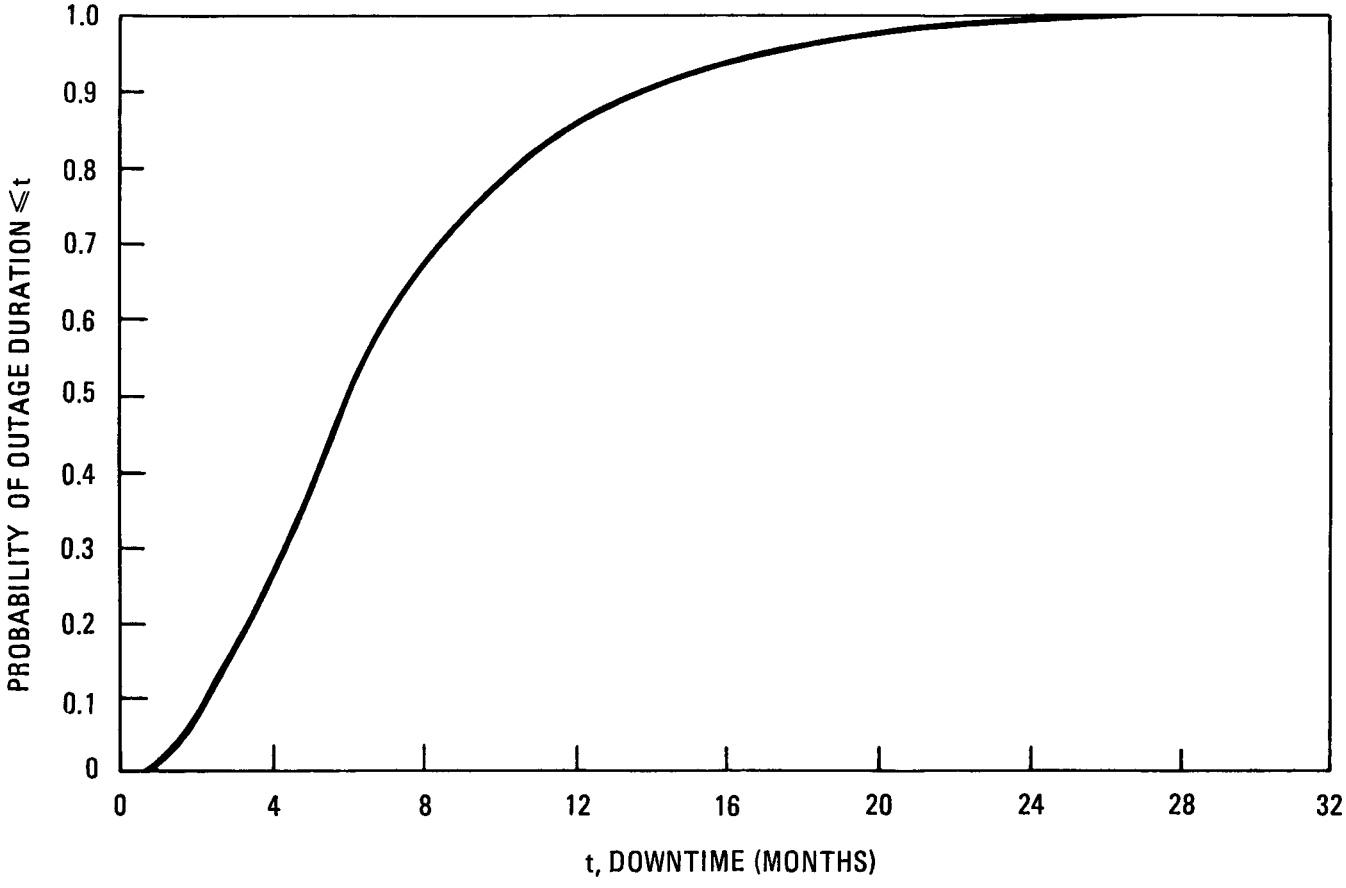


Fig. 7-10. Cumulative distribution for outage duration for consequence category SG-2

and $157 million, respectively. These costs ae dominated by the unrecovered cost of replacement power and process steam.

7.3.6. Seismic Events

A conservative scoping philosophy was adopted to evaluate the consequences of seismic events. The mean consequences of seismic activity range i were found by weighting the consequences of damage in each structural fragility class j by the conditional probability of damage in fragility class j given seismic activity in range i, according to

$$C_{mean,i} = \sum_{j=1}^{4} P_{ij} \times C_j \quad .$$

The structural fragility classes are described in Section 7.2.6. Estimates for downtimes and dollar valued consequences C_j of damage in each structural fragility class can be seen in Table 7-14. The consequences are proportional to downtime under the assumption that replacement power costs overwhelm any property repair costs that exceed insurance coverage. The estimates are orders of magnitude and were chosen to provide conservative estimates of investment risk. The conditional probability of damage in structural fragility class j occurring given seismic activity level i is based on the equations given in Section 6.3.8.

Table 7-15 lists the five seismic activity categories (SA), their median ground accelerations, and the corresponding consequences relevant to the investment risk assessment. Fragility data base is provided in Table A-12 of Appendix A.

TABLE 7-14
SEISMIC STRUCTURAL FRAGILITY CLASSES AND ASSOCIATED CONSEQUENCES

Structural Fragility Class	Description (Least Earthquake Resistant Equipment)	Median Ground Acceleration Capacity (g)	Logrithmic[a] Standard Deviation (β)	Mean Consequence ($M)	Downtime (months)
4	Nonseismic category I structural failures (nonsafety class structures and buildings)	0.48	0.52	1000	40
3	Category I structural failures (service water pumps)	0.63	0.39	2000	80
2	Equipment failure (except switchyards) (includes transformers, piping, etc.)	1.40	0.60	1000	40
1	Switchyard gear failures	0.20	0.32	60	2

[a] $\beta = \ln \sigma_g$

TABLE 7-15
SEISMIC ACTIVITY CATEGORIES AND MEAN CONSEQUENCES

Seismic Activity Category	Median Ground Acceleration (g)	Damage Description	Mean Consequence ($M)
SA-5	0.10	Minor switchyard damage	2
SA-4	0.15	Major switchyard damage	20
SA-3	0.20	Class II equipment damage	68
SA-2	0.25	Class I equipment damage	150
SA-1	0.30	Major Class I and Class II equipment damage	260

7.3.7. Turbogenerator Failure

Only nuclear power experience has been considered in determining the cost of turbomachine failures for the HTGR-SC/C plant. This is because nuclear plants typically integrate turbomachinery repair, whenever possible, into their scheduled maintenance and refueling schedule, which results in significantly different repair times than for conventional steam driven turbomachinery.

Damage category 3 consists of failure of from one blade up to a row of blades, or several blades in different rows. Repair times are in the range of one to three months for this type of failure, and are often performed concurrently with early refueling at nuclear plants. The mean repair time for this event is one month.

Damage category 2 consists of multiple rows of blades, shrouds, or disc rim failures. Repair of such failures ranges from one to six months, or even longer depending on the amount of replacement equipment that is available. The mean repair time for this event is five months, and extends well beyond any scheduled refueling outages.

Damage category 1 includes catastrophic events such as disc and machine housing failure which may also result in missiles being thrown from the machine. However, the category 1 consequences are based on the worst case found in the LWR data base that could be considered catastrophic, and does not involve missile generation. This is the cracked LP turbine rotor shaft at Wurgassen in February 1974. The mean time to repair for this event is 15 months.

Unrecovered costs due to turbine failure are based on a weighted average of frequency and expected turboset downtime for each damage category. Since there are three independent turbomachines in the HTGR SC/C design, i.e., 1 HP and 2 LP sets, a failure of any single set is likely to result in reduced plant electrical capacity until the next scheduled refueling or extended maintenance outage. In the event the

plant is operating in its full electrical mode, loss of a turbine may result in either a 50% (if HP turboset A fails) or a 25% (if IP turboset B or C fails) reduction in electrical output depending upon which of the three turbogenerator sets fails. The weighted unrecovered cost per month for HTGR-SC/C turbomachine failure is $11.3 M/month.

The expected repair times for each turbogenerator damage category and the associated unrecovered costs are presented in Table 7-16.

7.3.8. Inadvertent RSS Insertion

Based on discussions with HTGR design engineers, the following scenario is realistic for RSS ball removal from one region of the core. First, helium pumpdown and storage takes approximately one day. Next one half day is required for control rod drive removal, boron ball recovery, and insertion of another drive. Finally, another day is needed to return to power. Downtime is reduced if the event takes place while the reactor is shutdown for refueling, since the PCRV control rod penetrations are already open.

Table 7-17 presents the RSS insertion categories and corresponding downtime and consequences, based on scoping analyses.

7.3.9. Summary of Consequences

The unrecovered utility loss for each category of consequence described above is summarized in Table 7-18.

7.4. UNCERTAINTY ANALYSIS

The results of the consequence evaluation discussed in Sections 7.2 and 7.3 provided in many cases median predictions of the plant damage, outage times, and the resulting unrecovered financial loss. These predictions are based on best estimate assessments of physical and financial phenomena. To the extent that the values for the phenomena deviate

TABLE 7-16
TURBINE DAMAGE CATEGORIES
AND ASSOCIATED CONSEQUENCES

Turbogenerator Damage Category	Repair Time (mo)	Damage Description	Mean Cost Per Month ($M/mo)	Mean Cost ($M)
TG-3	1	Turbine blade damage	11.3	11.3
TG-2	5	Turbine disc damage	11.3	56.3
TG-1	15	Turbine failure	11.3	169.0

TABLE 7-17
CATEGORIES OF INADVERTENT RESERVE SHUTDOWN SYSTEM INSERTION
AND ASSOCIATED CONSEQUENCES

RSS Insertion Category	Description	Mean Downtime (mo)	Mean Consequence ($M)
RI-2	1 hopper bank inserted	0.10	3
RI-1	All hoppers inserted	2.40	72

TABLE 7-18
MEAN UNRECOVERED UTILITY LOSS BY CONSEQUENCE CATEGORY

Consequence Category	Description	Mean Loss ($ Million)
DC-9	No damage - minor delay	14.7
DC-8	$\leq$1/8 control rods replaced	48.5
DC-7	>1/8 control rods replaced; upper thermal barrier (TB) "failed" but acceptable	328.0
DC-5	Control rods ablate; upper TB "failed" but acceptable; plenum elements "damaged"	546.0
DC-4	Control rods ablate; upper TB "failed" but acceptable; containment contaminated	642.0
DC-3	Control rods ablate; upper TB suffered intermediate impairment; plenum elements "damaged"	642.0
DC-2	Control rods ablate; plenum elements failed; upper TB suffered intermediate impairment; liner and PCRV damaged but acceptable	801.0
DC-1	Uncontrolled core heatup	2700.0
LC-2	Severe environmental limit exceeded; PCRV concrete shown OK	94.0
LC-1	Extreme environmental limit exceeded; PCRV concrete needs repair	1591.0
FE-1	1 to 3 control blocks have offset shear failure	191.0
PC-3	0.01 in^2 leak releases 4-20% helium	14.0
PC-2	0.1 in^2 leak releases 20-75% helium	23.0
PC-1	>0.6 in^2 leak releases 75-100% helium	106.0
SG-2	Dump steam generator, leak primary coolant to atmosphere	157.0
SA-5	Minor switchyard damage	2.0
SA-4	Major switchyard damage	20.0
SA-3	Class II equipment damage	68.0
SA-2	Class I equipment damage	150.0
SA-1	Major Class I and II equipment damage	260.0
TG-3	Turbine blade damage	11.3
TG-2	Turbine disc damage	56.3
TG-1	Turbine failure	169.0
RI-2	Single RSS hopper bank released	3.0
RI-1	All RSS hoppers released	72.0

from their assessed median values, the accident consequences will deviate from their median values.

A method for assessing the uncertainties in consequence prediction was developed by GA during the AIPA safety assessment (Ref. 7-14). The method uses simplified mathematical algorithms describing the consequence controlling phenomena. The algorithms are used in a Monte Carlo error propagation program to simulate many investment risk consequence assessments. Cumulative probability distributions of independent variables are specified as input to the program. Appendix B describes the algorithms used for the financial loss uncertainty calculation. The appendix also lists the key parameters used in the simulation along with their values and uncertainty distributions. The median outage estimates as well as their uncertainty distributions are listed in Section 7.3 for several of the various consequence categories. Typically 30,000 Monte Carlo simulations were performed for each consequence category.

7.5. REFERENCES

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8. RISK ASSESSMENT RESULTS

The probabilities of accident sequences from Section 6 are taken with their consequences from Section 7 to provide investment risk plots in Section 8.1. The dominant contributors to the overall risk curve are presented in Section 8.2. Comparisons to proposed investment risk targets and interpretations of results are given in Section 8.3.

8.1. RISK PLOTS

The investment risk for the 2240 MW(t) SC/C HTGR is a function of the frequency of occurrence and the consequence to the owner/utility of the various accidents examined in Sections 6 and 7 of this report. Table 8-1 shows a summary of the frequencies and consequences for each category of consequence. The frequencies of occurrence and dollar consequences, along with their uncertainties, are utilized to yield a complementary cumulative distribution curve of frequency versus consequence (typically called a risk curve for safety PRAs).

Figure 8-1 shows a set of these cumulative frequency curves. Each curve represents a combination of the mean frequency, based on uncertainty distributions, and the consequence assessment with its uncertainty distribution for each of the consequence categories. The curves are asymptotic on the left to the mean accident frequency values and display the frequency per reactor year of exceeding a specified level of accident consequence. Also shown in Fig. 8-1 is an accumulated curve for each type of event. This curve is obtained by summing the mean frequencies of the consequence categories resulting from that type of event, at each consequence level.

Figure 8-2 repeats the accumulated curves for the eight types of events, and shows an overall investment risk curve obtained by summing

TABLE 8-1
SUMMARY OF FREQUENCIES AND UNRECOVERED UTILITY LOSSES
BY CONSEQUENCE CATEGORY

Consequence Category	Mean Frequency (Per Reactor-Year)	Mean Unrecovered Loss ($ Million)
Interrupted Core Cooling		
DC-9	4.0×10^{-4}	14
DC-8	7.0×10^{-6}	48
DC-7	3.7×10^{-5}	328
DC-5	3.4×10^{-6}	546
DC-4	1.4×10^{-5}	642
DC-3	3.8×10^{-6}	642
DC-2	8.5×10^{-6}	801
DC-1	3.8×10^{-5}	2700
Liner Cooling Loss		
LC-2	2.8×10^{-3}	94
LC-1	5.3×10^{-6}	1590
Fuel Element Cracking		
FE-1	5.0×10^{-6}	191
Primary Coolant Leaks		
PC-3	4.2×10^{-1}	14
PC-2	7.8×10^{-2}	23
PC-1	2.4×10^{-5}	106
Steam Generator Release		
SG-2	1.0×10^{-5}	157
Seismic Event		
SA-5	5.0×10^{-4}	1.8
SA-4	1.4×10^{-4}	20
SA-3	3.8×10^{-5}	68
SA-2	1.2×10^{-5}	150
SA-1	2.1×10^{-6}	260

TABLE 8-1 (Continued)

Consequence Category	Mean Frequency (Per Reactor-Year)	Mean Unrecovered Loss ($ Million)
Turbogenerator Failure		
TG-3	2.0×10^{-2}	11
TG-2	3.0×10^{-3}	56
TG-1	1.0×10^{-4}	170
RSS Insertion		
RI-2	2.0×10^{-1}	3.0
RI-1	1.0×10^{-5}	72

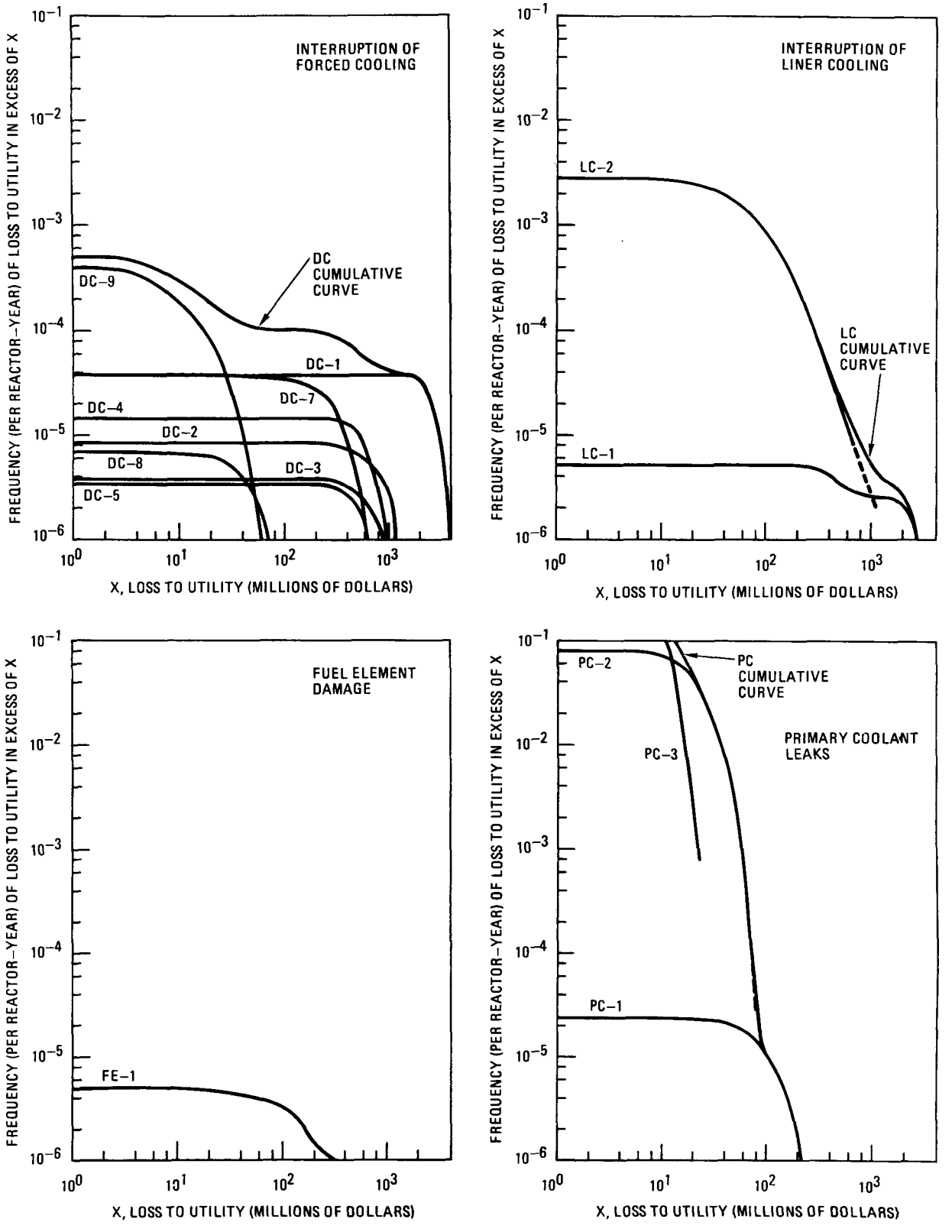

Fig. 8-1. Investment risk curves for each consequence category (sheet 1 of 2)

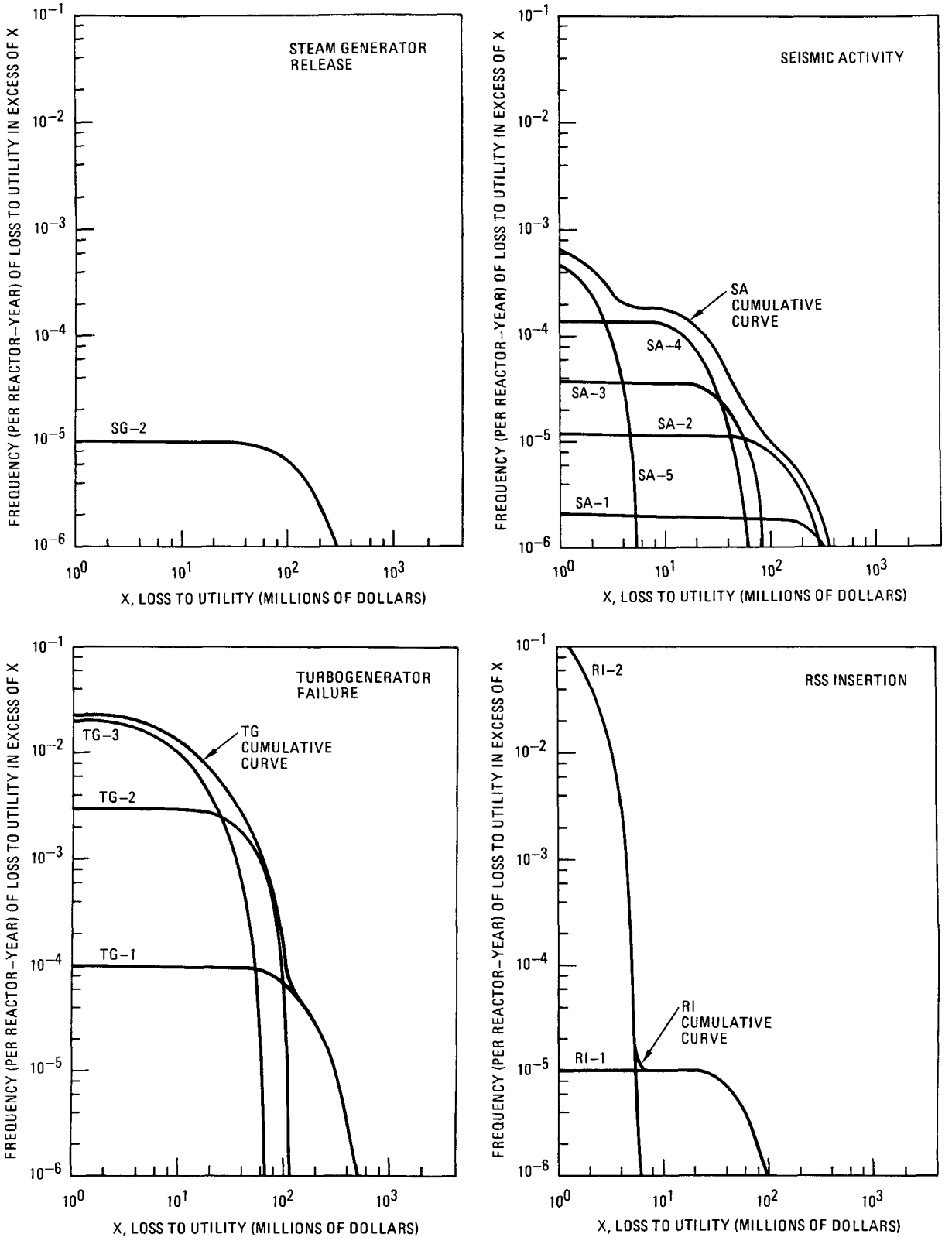

Fig. 8-1. Investment risk curves for each consequence category (sheet 2 of 2)

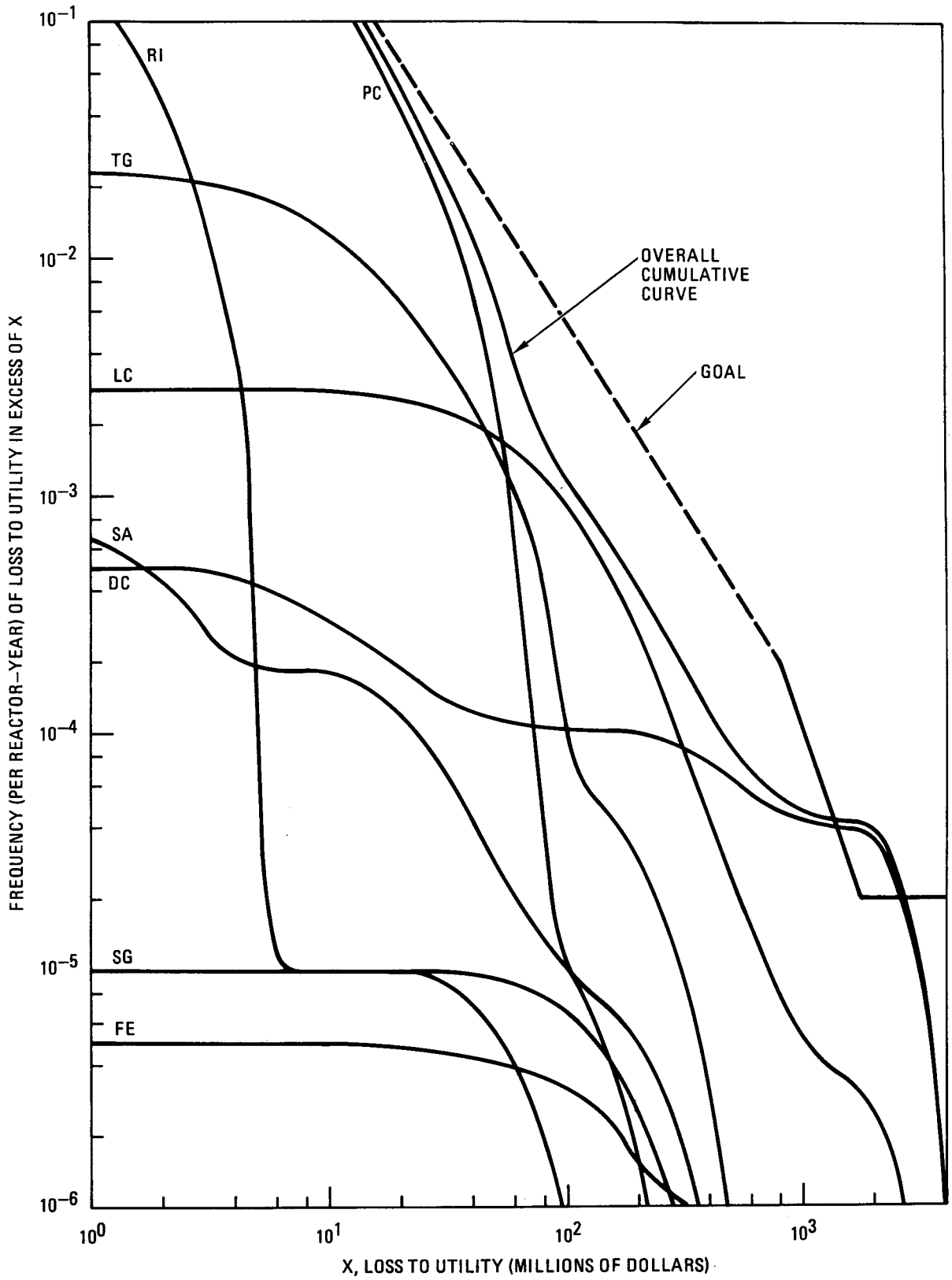

Fig. 8-2. Overall investment risk curve

the mean frequencies of the accumulated curves at each consequence level.

8.2. DOMINANT RISK CONTRIBUTORS

The overall investment risk envelope of Fig. 8-2 for the 2240 MW(t) HTGR-SC/C is dominated by primary coolant leaks (PC) at high frequencies, by liner cooling failures (LC) in the mid-frequency range and by interruptions of core cooling (DC) at low frequencies. Turbine-generator failures (TG) also contribute to the risk envelope in the mid-frequency range, but do not dominate. Refering back to Fig. 8-1 the particular consequence categories, within these broad groupings, that dominate the risk envelope are PC-2, LC-2, DC-1 and to a lesser extent TG-2. Consequence categories that do not make significant contributions to the risk envelope include the intermediate damage categories due to interruption of core cooling, DC-2 through DC-9, the more severe of the loss of liner cooling categories LC-1, the primary coolant leak categories PC-1 and PC-3, the steam generator leak category SG-2, the seismic activity categories SA-1 through SA-5, the least and most severe turbogenerator categories TG-3 and TG-1, and the reserve shutdown system insertion categories RI-1 and RI-2.

The highest frequency consequence category, dominating the upper portion of the risk envelope, is PC-2. The PC-2 scenario is characterized by instrument line failures or moderately sized leaks in PCRV penetrations. These leaks are estimated to vent 20 to 75% of the radiocontaminated primary coolant inventory to the containment building before they can be stopped. Such a leak has been assessed to occur at a mean frequency of about once in thirteen years and has a mean consequence of one month of plant downtime.

In the range of frequencies between 5×10^{-3} and 2×10^{-4}, the risk envelope is dominated by consequence category LC-2. Category LC-2 involves a loss of PCRV liner cooling in which, by timely reactor

shutdown and cooldown of the primary coolant loops, damage to the PCRV concrete is averted. However, because the severe environment temperature limit for the concrete is exceeded, a four-month outage is predicted during which time continued PCRV integrity is demonstrated to the satisfaction of both the plant operator and regulators.

The highest consequence category which dominates the risk envelope below about 4×10^{-5} per reactor-year is DC-1. This scenario includes all interruption of core cooling events that are of sufficient duration to preclude repair and restoration of the nuclear heat source to service. The consequences of category DC-1 are comparable to completely replacing the nuclear heat source, or 8.4 years of downtime (mean).

8.3. INTERPRETATION OF RESULTS

In general the risk resulting from the scenarios investigated in this assessment fall within the "allowed" region of the proposed investment risk goal (Fig. 8-2), many with substantial margin. While the goal is an older proposal and has been superseded as discussed in Section 4, comparing assessed risk to the goal remains a useful method of interpreting the assessment results.

Regarding the risk of interruptions in core cooling, note from Figs. 8-1 and 8-2 that the total probability per reactor-year of core (or core cavity internals) damage occurring is 1.1×10^{-4}. Ignoring those scenarios in which repair involves only the relatively easy replacement of control rods or plenum elements, the probability of core damage occurring is 5.5×10^{-5} per reactor-year. One way of interpreting this probability is to consider that with a total population of 100 reactors, all operating for 40 years, an event with a probability of occurrence of 5.5×10^{-5} per reactor would not be expected to occur even once within the whole population, though the assurance of this is only moderate.

Moderately sized primary coolant leaks and losses of liner cooling that do not result in concrete damage both dominate the risk envelope in one region or another but remain within the investment goal.

With regard to the risk stemming from steam generators, the assessment has not identified any significant contributing scenarios. However, the reader is cautioned that the investigation of possible steam generator related losses remains somewhat preliminary. One example of where further investigation could lead to a revised assessment is consideration of the types of unpredicted and relatively rapid steam generator degradations that have been experienced by several pressurized water reactors.

In all the scenarios, dominant or otherwise, the unrecovered loss to the utility is driven by outage time. This is due to two factors. The first factor is the relatively high cost of fossil fuels used in backup facilities over the course of the outage to provide replacement electric power and process steam. Second, for all but the most expensive scenarios, the one billion dollars in property damage insurance assumed to be carried by the plant owner is adequate to cover all repair and decontamination costs. Even in those cases where coverage is not sufficient to pay for the complete repair and decontamination, it does cover enough of these costs so that replacement power costs continue to dominate the accident cost.

The owning utility's unrecovered loss in providing replacement electric power and process steam can be mitigated by public utility regulators and contractual agreements with the steam user. Furthermore, the assessments of unrecovered loss are quite sensitive to modeling assumptions regarding these two factors. Because these two factors are not well known, large uncertainties in the cost model have resulted.

While risk curves resulting from most of the scenarios investigated fall within the investment risk goal with varying margin, that portion of the risk envelope dominated by DC-1, the extended interruption in

core cooling, crosses the goal line of Fig. 8-2. In order to better determine the significance of the assessment's compliance (or non-compliance) with a goal of avoiding irrepairable damage to the nuclear heat source, the assessment has been compared with newer investment protection criteria adopted by the DOE HTGR Safety and Investment Protection Working Group (Ref. 8-1).

As discussed in Section 4.2, the DOE goal differs from the proposed GA goal in three substantial ways. These are:

1. The goal is expressed in terms of plant outage time rather than dollar loss suffered by the plant operator.

2. The criteria on which the goal is based includes availability.

3. The quantitative requirements are somewhat more restrictive than those proposed by GA (Ref. 8-2).

Comparing the results of this investment risk assessment with the DOE goal requires two additional steps beyond those previously described in this report. First and most obvious, the dollar loss consequences for each accident category are set aside and instead the outage days associated with each category are used to specify consequence. Second, since the DOE goal specifies a limit on the total average annual outage rate, consideration needs to be given to those more commonly occurring upsets which, due to their higher frequency but relatively low consequence, were not considered as contributors to investment risk, but which taken in total dominate plant unavailability. A study of these events has been performed (Ref. 8-3) and for purposes of comparison with the DOE goals and demonstrating the integration of availability and investment risk, its results are included here. Appendix C provides an integrated table summarizing the results of Ref. 8-3 as well as the outage times associated with the various consequence categories of the investment risk assessment.

Note that a comparison of the risk assessment against the outage criteria of the DOE goal is readily accomplished by expressing the results in terms of downtime rather than dollar loss. However, the final criterion included in the DOE goal requires assurance that decontamination and decommissioning costs following any severe accident can be covered within the limits of currently available nuclear property damage insurance. While the risk assessment has examined decontamination in sufficient detail to assess accident costs (or downtimes) relative to the GA goal used throughout this study, investigation of decontamination and decommissioning costs so as to compare them to insurance limits is a new consideration which is beyond the scope of this assessment. Therefore, compliance with this final criterion of the DOE investment protection goal is not addressed here.

Figure 8-3 depicts both an interpretation of the DOE investment protection goal and the cumulative risk curve based on the results of this investment risk and the above-mentioned availability assessment. The right-hand, higher consequence portion of the curve is essentially a reinterpretation of Fig. 8-2 while the left-hand lower consequence portion of the line is based on the results of Ref. 8-3. The probabilistic variation in the availability portion of the curve is not included in Ref. 8-3 but is implicit in Markov theory (Ref. 8-4) on which the analysis is based. Note that the average outage rate (or plant availability) is based not only on the results of the more common events historically covered within availability studies such as the one used here but also by the outage contribution from rarer, more severe events considered normally in investment risk studies. Conversely the consequences for the more severe events identified within the availability study, including uncertainty distributions, are assessed along with investment risk events against the long outage aversion criterion.

Aside from the above discussion and illustration of the integration of availability and investment risk and the implicitly close relationship between the two disciplines, availability is not discussed further in this report. In particular, the plant's compliance with an average

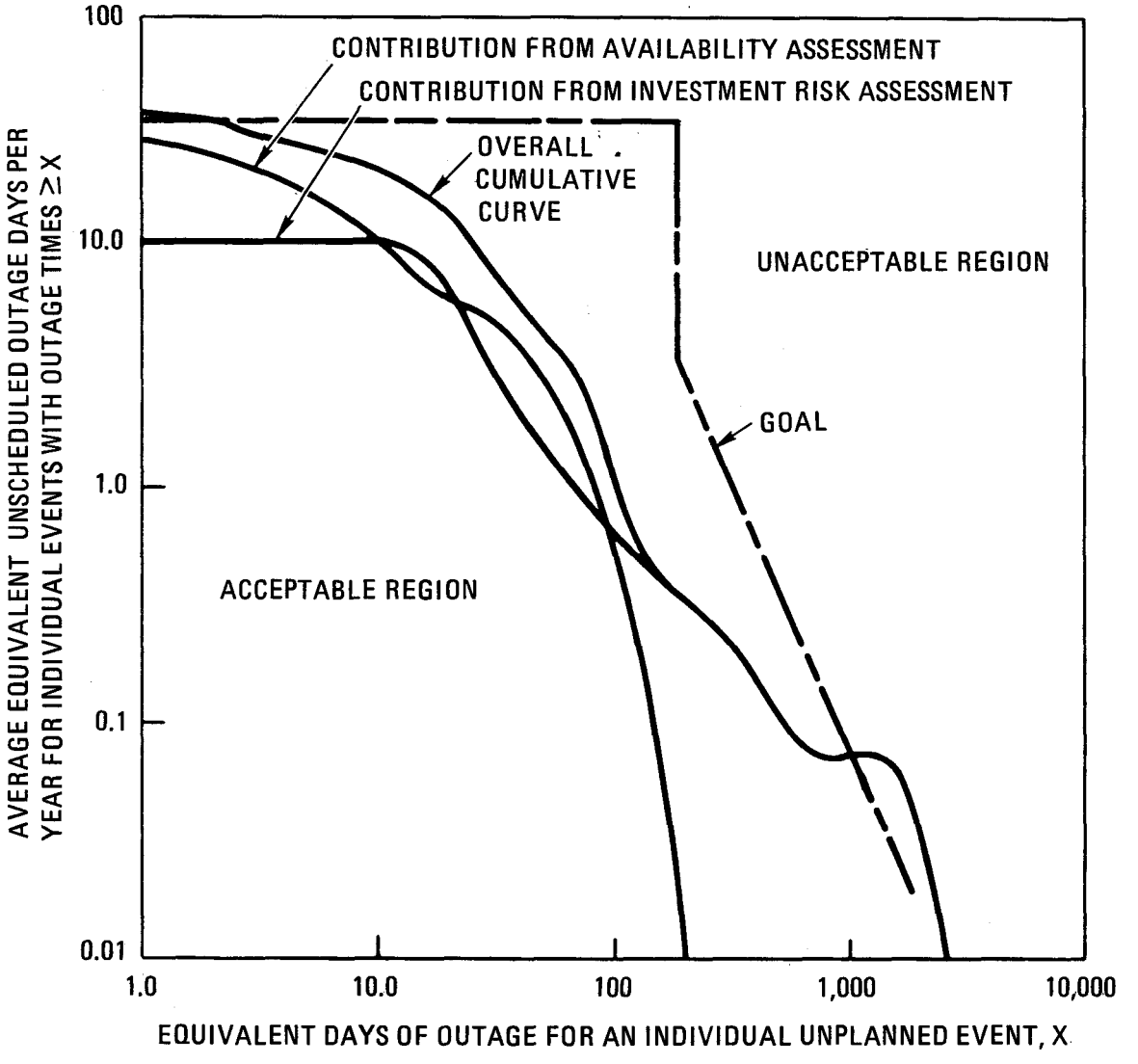

Fig. 8-3. Comparison of assessment with investment protection goal of the safety and investment protection working group

annual availability criterion was not intended to fall within the scope of this assessment. Rather the assessment is aimed at determining the plant's performance relative to aversion to high consequence events, the second criterion of the DOE goal.

As with the GA goal, the assessment generally falls within the allowable region of the goal, exceeding it only in the highest consequence region of the assessment where the risk is dominated by the damage category DC-1. This violation of the risk aversion criterion by extended interruptions in core cooling (DC-1) is significant. Severe accident risk has been studied in a quantitative manner for several years in both the context of safety and investment risk. The dominant event sequence leading to this extended cooling failure, identified in Fig. 6-1 consists of a delayed loss of main loop cooling in which a failure in the BOP leads to an orderly plant shutdown and a limited period of shutdown cooling on the main loops. However, following this limited shutdown cooling, the AHRS fails to start and repair efforts are unsuccessful prior to extensive heating of the core (MTRC). This scenario has been identified in every risk assessment of the reference HTGR design since the Accident Initiation and Progression Analysis (Ref. 8-5) in 1978 as dominating the frequency of cooling losses. Because of this, several enhancements to core cooling reliability have been incorporated into the design and, in fact, have led to a very high reliability in core cooling systems providing the HTGR with significant safety margin and investment protection against core cooling losses that exceeds that of industry.

However, the current trend in investment protection perception, as exemplified by both the GA proposal and DOE goal, includes a very restrictive aversion to long outages and irreparable damage. Despite these restrictions only the very low frequency interruption in core cooling is seen to violate the goal. For this case the assessment provides explicit guidance for improvements that can lead to meeting the goals.

8.4. REFERENCES

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9. ACKNOWLEDGEMENTS

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APPENDIX A
DATA BASE TABLES FOR FAULT TREES

TABLE A-1
DATA BASE FOR LOSS OF MAIN LOOP COOLING ASSESSMENT

Fault Tree Symbol	Description	Frequency		Probability				Repair (h)	Comments
		λ[a]	β[b]	α[c]	Q[d]	β	α		
X1	Spurious control signal isolates MLCS	0.04/yr	--	--	--	--	--	6	From Refs. A-1 and A-2
X2,X19	Turbine trip does not isolate reactor from grid	--	--	--	0.998	--	--	--	Estimated (see Ref. A-3)
X3,X20	Relief valve failure	3×10^{-3}/yr	--	--	0.03	--	--	24	Estimated from Refs. A-4 and A-5
X4	BOP pipe failure	2×10^{-3}/yr	--	--	--	--	--	--	From Refs. A-1 and A-2
X5	Failure of deaerator level control	0.03/yr	--	--	--	--	--	10	From Ref. A-4
X6,X7	Circulator failure (includes loss of service and power supply)	0.33/yr	8×10^{-3}	--	--	--	--	22	From Refs. A-3 and A-6 (see Ref. A-3 for τ)
X8	Failure to bypass feedwater heater leak	--	--	--	1×10^{-3}	--	--	24	From Refs A-1 and A-2

TABLE A-1 (Continued)

Fault Tree Symbol	Description	Frequency λ(a)	Frequency β(b)	Probability α(c)	Probability Q(d)	β	α	Repair (h)	Comments
X9	Feedwater heater leak	0.72/yr	--	--	--	--	--	--	From Ref. A-1 (includes all 3 feedwater heaters)
X10,X11	Feedwater heater drain pump failure	0.07/yr	0.02	--	--	--	--	40	From Refs. A-1 and A-2 (see, also, Ref. A-3)
X12,X13, X14	BFP failure	0.8/yr	0.02	0.3	0.01	0.18	--	40	From Refs. A-3, A-1, A-2, and A-5 (see Ref. A-3 for α)
X15	Common mode heat exchanger failure in process facility	5×10^{-4}/yr	--	--	--	--	--	--	Estimated (see Ref. A-3)
X16	Fire or explosion in process facility	2×10^{-3}/yr	--	--	--	--	--	--	From Ref. A-7
X17	Pip rupture - process facility and service lines	2×10^{-3}/yr	--	--	--	--	--	--	Estimated (see Ref. A-3)
X18	Failure of condensate return/ makeup system	1×10^{-3}/yr	--	--	--	--	--	--	Estimated (see Ref. A-3)

TABLE A-1 (Continued)

Fault Tree Symbol	Description	Frequency		Probability				Repair (h)	Comments
		λ[a]	β[b]	α[c]	Q[d]	β	α		
X21	Failure to bypass main turbine	--	--	--	5×10^{-3}	0.23	1	24	From Refs. A-3, A-1, A-2, and A-5 (see Ref. A-3 for α)
X22,X23	Turbine trip (main or auxiliary)	5.2/yr	0.07	--	0.1	0.07	--	--	From Refs. A-3, A-1, and A-8 (see Ref. A-6 for β)
X24	Failure to bypass auxiliary turbine	--	--	--	0.013	0.23	0.38	24	From Refs. A-3, A-1, A-2, and A-5 (see Ref. A-3 for α)
X26	Failure to isolate process steam line	--	--	--	1 x 10-3	--	--	24	Estimated (see Ref. A-3)
X27	Failure to isolate condensate return line	--	--	--	1×10^{-3}	--	--	24	Estimated (see Ref. A-3)
X28,X29	Condensate pump failure	3×10^{-5}/hr	0.02	0.3	3×10^{-3}	0.18	0.3	40	From Refs. A-3, A-1, A-2, and A-5 (see Ref. A-3 for α)
X30	Condenser/ condensate pump circuit valve fails	--	--	--	1×10^{-3}	--	--	24	From Ref. A-2

TABLE A-1 (Continued)

Fault Tree Symbol	Description	Frequency		Probability				Repair (h)	Comments
		λ[a]	β[b]	α[c]	Q[d]	β	α		
X31	Condenser failure	3×10^{-5}/hr	--	--	1×10^{-6}	--	--	60	From Refs. A-3 and A-2 (see Ref. A-3 for Q)
X32	Air ejection failure	3×10^{-6}/hr	--	--	1×10^{-7}	--	--	40	From Refs. A-3 and A-2 (see Ref. A-3 for Q)
X33	Condenser service water and heat sink failures	1×10^{-5}/hr	--	--	2×10^{-5}	--	--	40	From Refs. A-3 and A-2 (see Ref. A-3 for Q)
X34	Control system failure	--	--	--	7×10^{-5}	--	--	7	Estimated (see Ref. A-3)

[a] λ is the failure frequency for each system or component (1/hr).

[b] β is the fraction of all component or system failures which are due to common cause.

[c] α is the fraction of the common mode failures of redundant components or systems which result in an failure of diverse components or systems.

[d] Q is the failure to start probability for each system or component.

TABLE A-2
DATA BASE FOR AHRS FAILURE ASSESSMENT

Fault Tree Symbol	Description	Failure Frequency			Failure to Start Probability			Mean Time To Repair (h)
		λ[a]	β[b]	α[c]	Q[d]	β	α	
X1	HVAC ventilation	3×10^{-5}/hr (3)	0.2 (3)	0.01 (10)	3×10^{-4} (3)	0.14 (3)	0.05 (10)	24 (5)
X2	ACWS pump	3×10^{-5}/hr (3)	0.02 (10)	0.15 (3)	3×10^{-4} (3)	0.14 (3)	0.15 (3)	24 (5)
X3	ACWS relief	1×10^{-5}/hr (3)	0.23 (3)	1.0 (0)	--	--	--	24 (4)
X4	ABHX	1.6×10^{-4}/hr (3)	0.02 (10)	0.15 (3)	3×10^{-4} (3)	0.14 (3)	0.15 (3)	24 (5)
X5	ACWS piping	3×10^{-7}/hr (10)	0.02 (10)	0.04 (3)	--	--	--	30 (3)
X6	RPCWS unavailability	4.1×10^{-6}/hr (3)	0.08 (10)	1.0 (0)	--	--	--	24 (5)
X7	ACWS pressurizer	3×10^{-7}/hr (10)	0.2 (3)	0.04 (3)	--	--	--	10 (2)
X8	PPS	1×10^{-6}/hr (10)	1 (0)	1 (0)	1×10^{-5} (10)	1	1	6 (4)
X9	Operator fails to manually start CACS given the PPS fails	--	--	--	3×10^{-3} (10)	1 (0)	1 (0)	--
X10	Isolation valve	1×10^{-6}/hr (10)	0.22 (3)	1 (0)	3×10^{-4} (3)	0.22 (3)	0.11 (3)	--
X11	AHE	3×10^{-5}/hr (3)	2×10^{-3} (4)	0.04 (3)	--	--	--	--
X12	Auxiliary circulator	3.7×10^{-5}/hr (3)	8×10^{-3} (5)	1.0 (0)	3×10^{-4} (3)	0.14 (3)	1.0 (0)	22 (5)

[a] λ is the failure frequency for each system or component (1/hr).

[b] β is the fraction of all component or system failures which are due to common cause.

[c] α is the fraction of the common mode failures of redundant components or systems which result in a failure of diverse components or systems.

[d] Q is the failure to start probability for each system or component.

NOTE: The number in parentheses following each parameter value is the lognormal uncertainty factor ($\lambda_{0.95}/\lambda_{0.50}$). Table from Ref. A-8.

TABLE A-3
FAULT RATES FOR DIESEL GENERATORS USING
BINOMIAL FAILURE METHOD
(Table from Ref. A-8)

Units[b]	Diesel Failure Rates for i Replicate Units[a]		
	Lower Bound	Median	Upper Bound
r_1[c] ($\lambda\mu$)	1.3E-4	2.1E-4	3.0E-4
r_2 (β x r_1)	0.5E-6	3.1E-6	12.E-6
r_3	0.4E-7	6.0E-7	4.0E-6
r_4	0.0E-7	1.4E-7	16.E-7
r_5	0.0E-8	2.8E-8	68.E-8
β[d] (r_2/r_1)	0.00	0.02	0.10

[a] Middle number is point estimate. Lower and upper numbers from 90% interval estimate. Units for r_1 through r_5 are "events per calendar hour."

[b] r_i defines the total common mode failure rate at which i specific diesels fail simultaneously.

[c] r_1 defines the total failure rate for both independent and common cause failure (λ).

[d] β represents the probability, given that a specific diesel fails, that a second specific diesel will fail.

TABLE A-4
DATA BASE FOR FAILURE OF SERVICE WATER LEADING TO LOSS OF MAIN LOOP COOLING
(See Fig. 6-8)

Fault Tree Symbol	Description	Rate Q or λ	Command Faults		Mechanical Failures		Reference
			Common Mode Fraction	Repair Time	Common Mode Fraction	Repair Time	
X1	Suction obstructed	1.7×10^{-6}/h			1.0	8	A-9
X2	Four of 4 pumps fail to run	5×10^{-7}/h	0.90	6	0.10	70	A-6 and A-10
X3	Two pumps trip/valves fail	3×10^{-11}/h	0.90	6	0.10	65	A-6, A-10, and A-11
X4	Pump trips/valve fails	3×10^{-9}/h	0.90	6	0.10	65	A-6, A-10, and A-11
X5	Two of 3 pumps fail	3×10^{-6}/h	0.90	6	0.10	70	A-6 and A-10
X6	Pipe rupture	3×10^{-8}/h	--	--	1.00	30	A-2 and A-3
X7	Temperature control bypasses heat exchanger	6.2×10^{-7}/h	1.0	7	--	--	Estimate A-6, A-11, and A-12
X8	Two of 2 pumps fail	3×10^{-6}/h	0.90	6	0.10	70	A-6 and A-10
X9	Passive failures	6×10^{-8}	--	--	1.00	30	A-2 and A-3
X10	Same as X7						
X11	Same as X8						
X12	Same as X9						

TABLE A-5
NUCLEAR SERVICE WATER SYSTEM FAILS TO START
(See Fig. 6-10)

Fault Tree Symbol	Description	Rate $Q^{(a)}$ or $\lambda^{(b)}$	Common Mode $\beta_2^{(c)}$	β_3	$w'^{(d)}$	Failure Fraction (%)	Repair Time $\tau_m^{(e)}$	Command Fault Fraction (%)	Repair Time τ_c	Reference
X1	Electrical pump fails to start	1×10^{-3}/D	0.2	0.1	0.09	30	70	70	6	Ref. A-6 and A-10
X2	Air op valve fails to shut	3×10^{-4}/D	0.09		0.08	35	35	65	6	Ref. A-10 and A-11
X3	Air op valve fails to open	X2								
G1	NSWS fails to respond	2.3×10^{-4}/D								
G2	A and B pump fail to start	2×10^{-4}/D								
G3	Valves block A and B trains	3×10^{-5}/D								
G4	1 valve and 1 pump fail	2×10^{-6}/D								
G5	1 valve in "A" train fails	1.2×10^{-3}/D								
G6	1 valve in "B" train fails	1.2×10^{-3}/D								
G7	1 valve in either train fails	2.4×10^{-3}/D								

(a) Q is the median estimate of failure to start probability for each system or component.

(b) λ is the median estimate of failure frequency for each system or component, 1/hr.

(c) β_i is the probability that i redundant components fail given a failure occurs.

(d) w' is the lethal shock probability given that a failure occurred as described in Ref. A-10.

(e) τ is the median estimate of repair time required for each accessible system or component, hr. The subscript m refers to machinery failures while the subscript c refers to command and control faults.

TABLE A-6
REPAIR DATA USED IN EVENT 6
(See Figs. 6-8 and 6-10)

Repairs From G2 Fig. 6-8	p_i [a] G2 and G3	p_i [a] G2 Only	$1/\mu_i$ [b]	Component Multiplicity	$1/\bar{\mu}_i$
	Repair of Initiating Event Failure				
SWS Pumps				2	
Command	0.221	0.516	6		3.0
Failure	0.025	0.057	70		35.0
CW Pumps				4	
Command	0.037	0.086	6		1.5
Failure	0.004	0.010	70		17.5
Suction Lost	0.139	0.325	8	2	4.0
Rupture	0.006	0.006	30	1	30.0
Other	<0.001	<0.001			
Repairs From G3 Fig. 6-8		p_i [a] G3 Only			
NRPCWS or TBCCW Pumps				2	
Command	0.414	0.722	6		3.0
Failure	0.046	0.080	70		35.0
Temperature Control	0.102	0.178	7	1	7.0
Rupture	0.010	0.020	30	1	30.0
Repair of NSWS Fig. 6-10	p_i NSWS Fails To Start	p_i NSWS Fails To Run			
NSWS Pumps				2	
Command	0.60	0.9	6		3.0
Failure	0.26	0.1	70		70.0
Valves				2	
Command	0.08	0	6		3.0
Failure	0.04	0	35		17.5
Indep Pump				1	
Command	0.007	0	6		6.0
Failure	0.003	0	70		70.0
Indep Valve				1	
Command	0.006	0	6		6.0
Failure	0.004	0	35		35.0

[a] p_i is the probability that the ith component has failed given a failure has occurred.

[b] μ_i is the repair rate of the ith component, 1/hr.

TABLE A-7
DATA BASE FOR FAILURE OF THE ESSENTIAL RPCWS TRAINS A AND B
(See Fig. 6-11)

Fault Tree Symbol	Description	Rate $Q^{(a)}$ or $\lambda^{(b)}$	Common Mode Factors $\beta_2^{(c)}$	β_3	$w'^{(d)}$	Failures Fraction (%)	Repair Time $\tau_m^{(e)}$	Command Fault Fraction (%)	Repair Time $\tau_c^{(e)}$	Reference
X1	Containment valves shut	2×10^{-5}/yr	3×10^{-8}/yr = 0.09					24		A-6 and A-11 estimated
X2	Level error (pressurized)	5×10^{-7}/yr	Operator missets 2 switches, 2 controls drift			N/A	--	100	6.0	A-6
X3	Heat exchanger fails	3×10^{-6}/hr	2×10^{-3}			100	30	N/A	--	A-6
X4	Pressurizer or pipe rupture	3×10^{-8}/hr	0.2			100	170	N/A	--	USAEC-4607
X5	Temperature control valve (V1)	3×10^{-8}/hr	0.09			5	24	95	6.0	A-6 and A-11
X6	Electric pump fails to run	3×10^{-5}/hr	0.1		5×10^{-3}	10	70	90	6.0	A-6 and A-10
X7	Electric pump fails to start	1×10^{-3}/D	0.2	0.1	0.09	30	70	70	6.0	A-6 and A-10
X8	Check valve fails to open	5×10^{-5}/D	0.5			100	24	0	--	A-10 and A-11
X9	Check valve fails to close	1×10^{-4}/D	0.1			100	24	0	--	A-11
X10	Standby pump isolated	4×10^{-6}/D	0.1			N/A	--	100	0.5	
G1	Failure of vital A and B RPCWS	2.1×10^{-7}/hr = 1.8×10^{-3}/yr								
G2	Pressure boundary ruptures	1.2×10^{-8}/hr								
G3	Temperature control valve isolate coolers	4.3×10^{-8}/hr								
G4	Pump fails in "A" and "B" trains	1.5×10^{-7}/hr								
G7	Pumping failure in "A" and "B" trains	1.5×10^{-7}/hr								

(a) Q is the median estimate of failure to start probability for each system or component.

(b) λ is the median estimate of failure frequency for each system or component, 1/hr.

(c) β_i is the probability that i redundant components fail given a failure occurs.

(d) w' is the lethal shock probability given that a failure occurred as described in Ref. A-10.

(e) τ is the median estimate of time required for each accessible system or component, hr. The subscript m refers to machinery failures while the subscript c refers to command and control faults.

TABLE A-8
DATA BASE FOR FAILURE OF SHUTDOWN COOLING ON MAIN LOOPS
(See Fig. 6-14)

Event Tree Symbol	Description	λ or Q Rate	Common Mode Factors			Reference
			β	β_3	w'	
X1	NE RPCWS or TB CCW fails	1×10^{-5}				(see Section 6.3.3)
X2	Spurious control system trip	5×10^{-6}/hr				A-3
X3	Piping rupture	3×10^{-7}/hr				A-6
X4	Reflief valve spurious open	3×10^{-8}/hr	0.25			A-6
X5	Circulator fails to run	4×10^{-5}/hr	8×10^{-3}			A-8
X6	Circulator water pumps fail to run	3×10^{-5}/hr		0.018	5×10^{-3}	A-6 and A-10
X7	Feed pump fails to run	3×10^{-5}/hr			5×10^{-3}	A-6 and A-10
X8	Condensate pump fails to run	3×10^{-3}/hr		0.037	5×10^{-3}	A-6 and A-10
G1	Shutdown cooling fails	1.7×10^{-5}/hr				
G2	Primary loops fail	5.32×10^{-6}/hr				
G3	BOP fails	2.12×10^{-6}/hr				
G4	Circulators fail	3.2×10^{-7}/hr				
G5	Pumping failure	1.79×10^{-6}/hr				
G6	Four of 4 CW pumps fail	5.4×10^{-7}/hr				
G7	Five of 5 feed pumps fail	1.5×10^{-7}/hr				
G8	Three of 3 condensate pumps fail	1.1×10^{-6}/hr				

TABLE A-9
DATA BASE FOR ESSENTIAL RPCWS REPAIR
(See Fig. 6-12)

Fault Tree Symbol	$1/\mu_i$ (a)	No. of Component	$1/\bar{\mu}_i$	p_i (b)
G2				
X3	30	2	15	0.029
X4	170	2	85	0.029
G3				
Command	6	2	3	0.195
Failure	24	2	12	0.010
X1	6	1	6	0.013
G4				
X2	6	2	3	3×10^{-4}
G7				
Command	6	4	1.5	0.579
Failure	70	4	17.5	0.145

(a) μ_i is the repair rate of the ith component, 1/h.

(b) p_i is the probability that the ith component has failed given a failure has occurred.

TABLE A-10
DATA BASE FOR THERMAL SHOCK TO THE STEAM GENERATOR
(See Fig. 6-17)

Fault Tree Symbol	Description		Reference
X1	Steam generator leak and dump	$\lambda = 0.3/yr$ (4)	A-8 and A-13
X2	PPS fails to supply circuit trip signal	$Q = 9 \times 10^{-6}/D$ (10)	A-3
X3	Circuit breaker fails to open on demand	$Q = 1 \times 10^{-3}/D$ (3)	A-6
	Failure of redundant breaker to open given that breaker failed to open	$\beta = 0.2$	A-14
X4	Spurious opening of dump valve set	$\lambda = 1 \times 10^{-3}/yr$	A-6
X5	Rupture of feedwater line between feed valves and steam generator	$\lambda = 4 \times 10^{-4}/yr$	A-6
X6	Circulator failure to trip (X6 = G3)	$Q = 2.1 \times 10^{-4}/D$	Calculated
G1	Dry steam generator with operating circulator	$6.3 \times 10^{-5}/yr$	
G2	Steam generator leak, dump, and no circulator trip	$6.3 \times 10^{-5}/yr$	
G3	Circulator fails to trip	$2.1 \times 10^{-4}/D$	
G4	Circuit breakers A and B fail to open on demand	$2 \times 10^{-4}/D$	
G5	Lost water and no circulator trip	$3 \times 10^{-7}/yr$	
G6	Steam generator inventory lost without tube leak	$1.4 \times 10^{-3}/yr$	

TABLE A-11
DATA BASE FOR SEISMIC EVENT FREQUENCIES
THE SEISMIC INITIATING EVENT VECTOR - ZION PLANT

Probability Per Curve (P_j)	Acceleration (g's) (g_i)									
	0.125	0.175	0.225	0.275	0.35	0.45	0.55	0.65	0.75	0.85
0.056	1.0-4	2.6-5	1.2-5	5.4-6	4.7-6	2.9-6	0	0	0	0
0.088	1.1-4	3.7-5	1.7-5	8.0-6	6.9-6	2.6-6	2.4-6	0	0	0
0.056	1.6-4	5.3-5	2.4-5	1.3-5	1.1-5	4.2-6	2.1-6	2.6-6	0	0
0.14	8.6-5	1.1-5	7.1-6	3.1-6	1.9-6	8.9-7	0	0	0	0
0.22	1.1-4	2.9-5	1.0-5	3.7-6	2.5-6	6.5-7	3.4-7	0	0	0
0.14	1.9-4	4.7-5	1.6-5	6.6-6	3.9-6	1.0-6	3.0-7	1.9-7	0	0
0.084	3.0-4	1.0-4	3.8-5	1.9-5	1.5-5	8.9-6	0	0	0	0
0.132	3.6-4	1.3-4	4.7-5	2.6-5	2.2-5	7.7-6	7.3-6	0	0	0
0.084	4.7-4	1.7-4	7.3-5	3.6-5	3.4-5	1.3-5	6.3-6	7.7-6	0	0

Earthquake frequency f:

$$f(g_1 \leq g \leq g_2) = \sum_{i=1}^{N} P_j \left[f(g_{i+1}) - f(g_i) \right]$$

TABLE A-12
SEISMIC FRAGILITY OF KEY ZION STRUCTURES AND EQUIPMENT

Symbol	Structure/Equipment	$\tilde{\tilde{a}}$	β_R	β_U
1	Offsite power ceramic insulators	0.20	0.20	0.25
2	125 Vac distribution panel[a]	0.60	0.37	0.50
3	125 Vdc buswork[a]	0.60	0.37	0.50
4	Service water pumps	0.63	0.15	0.36
5	4160 V switchgear (chattering)[a]	0.72	0.35	0.47
6	480 V switchgear (chattering)[a]	0.72	0.36	0.47
7	480 V motor control centers (chattering)[a]	0.72	0.36	0.47
8	Auxiliary building-failure of concrete shear wall	0.73	0.30	0.28
9	Refueling water storage tank	0.73	0.30	0.28
10	Interconnecting piping/soil failure beneath reactor building	0.73	--	0.33
11	Impact between reactor and auxiliary buildings	0.79[b]	0.28	0.41
12	Condensate storage tank	0.83	0.28	0.29
13	4160 V diesel generators[a]	0.86	0.35	0.37
14	Crib house collapse of pump enclosure roof	0.86	0.24	0.27
15	Safety injection pumps	0.90	0.20	0.37
16	Containment ventilation ductwork and dampers	0.97	0.20	0.62
17	125 Vdc batteries and racks	1.01	0.28	0.63
18	Core geometry	1.16	0.25	0.42
19	Reactor coolant system relief tank	1.19	0.20	0.63
20	4160 V transformer	1.39	0.25	0.60
21	Service water system buried pipe 48 in.	1.40	0.20	0.57
22	CST piping 20 in.	1.40	0.20	0.57
23	Auxiliary building - failure of concrete roof diaphragm	1.40	0.31	0.33
24	Failure of masonry walls	1.70	0.50	0.26
25	Containment ventilation system fan coolers	1.74	0.49	0.23
26	Collapse of pressurizer enclosure roof	1.80	0.39	0.34

[a] Fragility values indicated are for chatter, relay trip, or other intermittent or easily recoverable conditions. Nonrecoverable failure is expected to occur at about three times the indicated fragility value.

[b] Applicable only with a median lower bound of 0.74 g and $\beta_U = 0.29$.

TABLE A-13
TURBOGENERATOR FAILURE CATEGORIES

Scenario Identification	Occurrence Frequency	Data Base	Typical Scenario Description
3	10^{-1} to 10^{-2}/yr	400 LWR turbine years	One to several blades break off at operating speed causing the machine to experience higher vibrations. The vibration detection causes the operator to shut the machine down for detailed inspection as to the cause.
2	10^{-2} to 3×10^{-4}/yr	400 LWR turbine years, reported failures in 92,000 steam turbine years, 7,000 years of jet engine experience	Material ingestion into the turbine or compressor section causes mechanical damage to several rows of blades over several minutes while operator tries to shut the machine down before excessive vibration causes additional damage. (At least 6 disc failures.)
1	Less than 3×10^{-4}/yr a) 6×10^{-5}/yr b_1) 6×10^{-5}/yr b_2) 1×10^{-5}/yr c) 1×10^{-4}/yr	92,000 steam turbine years, 7,000 jet engine years	a) At least 6 failures due to overspeed occurred where faulty valve operation on loss of generator load caused a machine overspeed beyond its design limits. About 1/2 of the discs in the machine might break apart at various speeds during about a 1 s period. The machine then halts abruptly due to the deformation of remaining parts. b) At least 7 failures due to materials most likely resulted in several discs breaking up over one shaft revolution per disc separation. An abrupt halt of the machine occurs due to component deformation and shaft breakage is a likely consequence. c) At least 13 failures due to catastrophic generator failure resulted in halt of the machine and component deformation.

TABLE A-14
DATA BASE FOR INADVERTENT RSS INSERTION FAULT TREE
(See Fig. 6-20)

Fault Tree Symbol	Description		Reference
X1	Operator not cognizant of RSS hopper release during surveillance	$P = 1 \times 10^{-3}$	A-3
X2	Frequency of single RSS hopper release during surveillance	$\lambda = 1 \times 10^{-3}$/yr	A-3
X3	Conditional probability operator attempts startup if unaware of RSS hopper	$P = 1.0$	--
X4	Frquency of single RSS hopper release, any of 82 in core	$\lambda = 8.2 \times 10^{-2}$/yr	A-3
X5	Conditional probability RSS is armed during surveillance	$P = 1.0$	--
X6	Conditional probability replacement hopper passes test	$P = 0.99$	Estimated
X7	Frequency of single hopper release due to mechanical failure during surveillance	$\lambda = 1 \times 10^{-1}$/yr	A-15
X8	Conditional probability all hoppers are tested if one fails	$P = 1.0$	--
X9	Conditional probability replacement hopper does not pass surveillance test	$P = 0.01$	Estimated
X10	Frequency of RSS hopper release assuming replacement hopper fails surveillance test	$\lambda = 5 \times 10^{-1}$/yr	Estimated
X11	Conditional probability of instrument error during reactor trip (assuming monthly surveillance)	$P = 1.7 \times 10^{-3}$ ($P = 1/12 \times 2.2 \times 10^{-2}$)	A-16
X12	Reactor trip frequency	$\lambda = 1.8$/yr	A-2
X13	Conditional probability operator inserts hopper bank based on instrument error	$P = 1.0$	--
X14	Conditional probability of no instrument error during reactor trip	$P = 1.0$	--
X15	Conditional probability of operator error during reactor trip (RSS insertion)	$P = 1 \times 10^{-3}$	A-3
X16	Electrical failure frequency causing RSS insertion during operation	$\lambda < 1 \times 10^{-6}$/yr	A-16
X17	Mechanical failure frequency causing RSS insertion	$\lambda < 1 \times 10^{-6}$/yr	A-16

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APPENDIX B
FINANCIAL EQUATIONS AND DATA

The purpose of this appendix is to describe the economic model that was used to evaluate the costs incurred by a utility due to an accident induced outage. During such an outage the portion of plant operations and maintenance that is associated with power production no longer goes on and thus a partial savings is realized. A further savings is realized by no longer "burning" the nuclear fuel. However, during the outage period, the demand for both process steam and electric power is unaffected by the accident and the model assumes that the SC/C owner continues to be responsible for meeting these demands. Therefore, the owning utility faces a sizable expense as fossil fuels are burned as a substitute for the incapacitated nuclear heat source. Backup fossil fueled process steam capacity is assumed to be owned by the industrial user, but fueled by the SC/C owner. Reserve fossil fueled electric power generating capacity is assumed to be owned by the utility owning the SC/C. Additional expenses incurred by the utility are plant repair and decontamination (if required) costs.

Insofar as the Three Mile Island-II accident is representative of the expected reaction of public utility regulators, removal of the plant from the utility's rate base is assumed, regardless of the expected duration of the outage. Of course, this action has a large negative effect on the utility's cash flow.

Several avenues are available to recover the expenses and possible loss of income resulting from an accident. The first of these is insurance. As described in Ref. B-1, up to 1.0 billion dollars of property insurance is available to a nuclear utility. In only a couple of damage categories is the cost to repair (including component procurement, decontamination, and labor) estimated to be in excess of the available

insurance. Therefore, in most cases the unrecovered utility loss is driven by the cost of replacement electric power and process steam. Replacement electric power insurance is available, though coverage is somewhat modest, and is assumed to be carried by the SC/C owner. The coverage includes two years of outage following a six-month waiting period (essentially a deductible on the policy). In the first year covered, payments can be up to 2.3 million dollars per week while during the second year payments are half of those in the first year.

Another source of recovery considered by the model is income received for the replacement electric power and process steam being provided. It is assumed that the price paid by the industrial steam user for replacement steam is the price agreed upon for nuclear generated steam plus half the difference on the additional cost. In the case of replacement electric power, with the plant removed from the rate base, the income received for replacement electric power is determined by public utility regulators. Theoretically the percentage of the uninsured replacement power costs recovered through rate adjustment could vary between 0 and 100%. However, the likelihood of the rate adjustment not being worth at least the loss of the SC/C plant in the rate base is considered remote. In fact, it is assumed that 75% of the cost of replacement electricity is recovered through rate adjustment.

Finally, income tax credit resulting from the accident is considered as mitigating the accident cost.

The model as programmed into the STADIC computer code (Ref. B-2) is a summation of terms each of which consider one aspect of a utility's finances as affected by an accident. In particular,

$$\begin{aligned}\text{Net Unrecovered} \\ \text{Loss to Utility}\end{aligned} = AA + AB + AC + AD + AE + AF + AG + AH + AI + AL + AO + BC + SUR + TAX + RINS + AJAK$$

Terms reflecting a savings to the utility include AA and AB. Terms reflecting the costs of generating electric power and steam with more costly fossil fuels in backup plants include AC, AD, and BC. Direct repair and decontamination of the power plant and fuel replacement costs are considered in terms AE and AF, respectively. Terms AG, AH, and AI account for removing the plant, the nuclear fuel and operations and maintenance costs from the utility's rate base. Recovery of expenses through rate adjustment by utility regulators is treated in terms AJAK and AL. Term AO treats the recovery of the cost of replacement process steam from the industrial user(s). The terms SUR and RINS model the insurance coverage that is available for property damage and decontamination costs, and for replacement power costs, respectively. The recovery of losses through income tax credits is reflected in term TAX.

The values of these terms are determined using the equations listed below. The variables used in the equations are described after all the equations have been listed. The values assigned to these variables for this assessment are listed in Table B-1.

AA = savings due to no nuclear fuel "burnup" during the outage

$$= \text{BURN} * \left(1.0 + \frac{\text{ESCAA}}{100}\right)^{\text{LAT}} * \text{LFAA} * \text{KWTRAT} * 8760 * \text{CF} * \text{YR} * 3.413$$

AB = reduction in operations and maintenance costs

$$= \text{VAROM} * \left(1 + \frac{\text{ESCAB}}{100}\right)^{\text{LAT}} * \text{LFAB} * \text{KWTRAT} * 8760 * \text{CF} * \text{YR}$$

AC = cost of continuing to supply electric power, in terms of capacity

$$= -\text{CAPCOS} * \text{KWE} * \text{YR} * 1000.$$

BC = cost of burning nonnuclear fuels to continue providing industrial steam

$$= -\text{OILBTU} * \text{KWT} * \frac{1}{\text{EBOIL}} * 8760 * \text{CF} * \text{YR} * \left(1 + \frac{\text{ESCBC}}{100}\right)^{\text{LAT}} * \text{LFBC} * 3.413$$

AD = cost of continuing to supply electric power, in terms of nonnuclear fuel expenses

$$= -\text{MBTU} * \text{KWE} * \text{HTRATE} * 8760 * \text{CF} * \text{YR} * \left(1 + \frac{\text{ESCAD}}{100}\right)^{\text{LAT}} * \text{LFAD}$$

AE = direct costs for repair and decontamination of the power plant

$$= -\text{PLTREP} * \left(1 + \frac{\text{ESCAE}}{100}\right)^{\text{LAT}} * \text{LFAE}$$

AG = loss due to removing the plant from the utility's rate base

$$= -\frac{\text{FACCAP}}{100} * \text{CONSTR} * \text{KWTRAT} * \frac{\text{FCR}}{100} * \text{YR} * 1000$$

AH = loss due to removing nuclear fuel costs from utility's rate base

$$= -\frac{\text{FACFCC}}{100} * \text{FCC} * \left(1 + \frac{\text{ESCAA}}{100}\right)^{\text{LAT}} * \text{LFAA} * 8760 * \text{CF} * \text{KWTRAT} * \text{YR} * 3.413$$

AI = loss due to removing operations and maiantenance costs from rate base

$$= -\frac{\text{FACOM}}{100} * \text{AB}$$

SUR = recovery of property damage and decontamination costs from property insurance

$= -AE$ if $AE < \$1 \times 10^9$

$= \$1 \times 10^9$ if $AE \geq \$1 \times 10^9$

RINS = recovery of replacement power costs from NEIL I insurance

If $YR \leq 0.5$; RINS = 0.0

If $0.5 < YR < 1.5$; TIME = YR - 0.5
RINS1 = TIME * $\$119.6 \times 10^6$
RINS2 = -0.9 * (AC + AD)
RINS = minimum of RINS1 or RINS2

If $1.5 < YR < 2.5$; TIME = YR - 0.5
RINS1 = [1/2(TIME-1) + 1] * $\$119.6 \times 10^6$
RINS2 = -0.9 [1/2(TIME-1) + 1] * (AC+AD)
RINS = minimum of RINS1 or RINS2

If $2.5 < YR$; RINS1 = 1.5 * $\$119.6 \times 10^6$
RINS2 = -0.9 * 1.5 * (AC + AD)
RINS = minimum of RINS1 or RINS2

TAX = recovery of losses through income tax credit

$= -0.5 * (AE + SUR)$

AO = recovery of the cost of replacement process steam from the industrial user(s)

$= -\frac{FACSTE}{100} * BC$

AJAK = recovery of uninsured cost of producing replacement electric power, considering both capacity costs and energy costs

$$= \frac{FACREP}{100} * [-(AC + AD) - RINS]$$

AL = rate recovery of uninsured cost of restoring plant to service, considering plant repair and/or decontamination

$$= \frac{FACPLT}{100} * [-AE - SUR - TAX]$$

Levelization factors, LFAA, LFAB, and LFAE are found as follows:

$$LF(\ ) = \frac{K(1-K^N)}{1-K} \times \frac{D}{1 - \frac{1}{(1+D)^N}}$$

where $K = \frac{1 + ESC(\ )}{1 + D}$

ESC( ) = Escalation rate

D = Discount rate

N = Plant life

A brief description of the numerous other variables as well as a discussion concerning their estimated value is given below. In most cases an uncertainty has been associated with the variable and this uncertainty is listed along with the single value estimate in Table B-1. The "curve type" listed in the far right column of the table refers to one of the characteristic uncertainty distributions shown in Figures B-1 through B-5.

BURN - This variable is only the burnup portion of the HTGR nuclear fuel cycle cost. Its value depends on the fuel

TABLE B-1
EVALUATION OF INVESTMENT RISK ECONOMIC MODEL INPUT VARIABLES

Variable	Description	Single Value Estimate	Most Likely	Range 1% Low	Range 99% High	Curve Type
BURN	= Burnup component of nuclear fuel costs ($/MBTU)	1.21	1.28	0.83	1.55	A
CAPCOS	= Capacity charge for replacement electric power [$/KW(e)-YR]	71	71	43	112	C
CAPSTM	= Capacity charge for replacement steam [$/KW(t)-YR]	33	33	23	36	D
CFE	= Capacity factor for electric power (%)	75	65	50	75	E
CFS	= Capacity factor for steam (%)	80	65	50	80	F
CONSTR	= Capital construction cost of damaged plant [$/KW(t)]	712	712	570	1,069	G
DI	= Industrial financing discount rate (%)	8.5	8.5	8.0	9.5	H
DU	= Utility financing discount rate (%)	4.4	4.4	3.9	5.4	I
EBOIL	= Boiler efficiency of replacement steam system (%)	82	86	80	90	J
ESCAA	= Yearly real escalation rate of nuclear fuel costs (%)	0	0	-1.4	1.4	M
ESCAB	= Yearly real escalation rate of O&M costs (%)	1.0	0	0	0	--
ESCAD	= Yearly real escalation rate of fossil fuel used to generate electrical energy (%)	2.3	2.3	1.9	2.9	K

TABLE B-1 (Continued)

Variable	Description	Single Value Estimate	Most Likely	Range 1% Low	Range 99% High	Curve Type
ESCAE	= Yearly real escalation rate of plant repair cost (%)	0	0	0	0	--
ESCBC	= Yearly real escalation rate of fuel oil (%)	2.9	2.9	2.4	3.4	Linear
FACCAP	= Portion of plant capital cost removed from rate structure (%)	100	100	0	100	(b)
FACENG	= Portion of replacement power energy charge recovered through rate adjustments (%)	75	75	0	100	(b)
FACFCC	= Portion of nuclear fuel cycle cost removed from rate structure (%)	100	100	0	100	--
FACFUL	= Portion of nuclear fuel replacement cost recovered through rate adjustments (%)	0	0	0	8	(b)
FACOM	= Portion of O&M removed from rate structure (%)	45	45	0	100	(b)
FACPLT	= Portion of HTGR plant repair cost recovered through rate adjustments (%)	0	0	0	8	(b)
FACREP	= Portion of replacement power capacity charge recovered through rate adjustments (%)	75	75	0	100	(b)
FACSTE	= Portion of replacement steam energy charge recovered through rate adjustments (%)	0	0	0	75	(b)
FCC	= Nuclear fuel cycle cost ($/MBTU)	1.33	1.40	0.92	1.81	A

TABLE B-1 (Continued)

Variable	Description	Single Value Estimate	Most Likely	Range 1% Low	Range 99% High	Curve Type
FCR	= Levelized normal nuclear fixed charge rate (%/YR)	8.5	8.5	8.0	9.0	Linear
FULRUP	= Nuclear fuel replacement cost ($\$ \times 10^6$)	138	138	138	175	(b)
HTRATE	= Heat rate of plant used to generate replacement energy [BTU/KW(e)-HR]	10,600	10,600	8,700	10,600	Linear
KWE	= Electric output of plant [MW(e)]	470	470	64	635	(b)
KWT	= Thermal output of plant to process plant [MW(t)]	1,141	1,411	1,120	2,128	(b)
KWTRAT	= Nuclear plant rated thermal power [MW(t)]	2,240	2,296	2,160	2,340	N
LAT	= Time from base year to startup of nuclear plant (years)	22	22	15	30	(b)
LFAA	= Levelization factor using ESCAA escalation rate, D discount rate, and N plant life	1.0				
LFAB	= Levelization factor using ESCAB escalation rate, D discount rate, and N plant life	1.0	1.0	1.0	1.0	--
LFAD	= Levelization factor using ESCAD escalation rate, D discount rate, and N plant life	1.21	1.21	1.09	1.43	(b)
LFAE	= Levelization factor using ESCAE escalation rate, D discount rate, and N plant life	1.0	1.0	1.0	1.0	--

TABLE B-1 (Continued)

Variable	Description	Single Value Estimate	Most Likely	Range 1% Low	Range 99% High	Curve Type
LFBC	= Levelization factor using ESCBC escalation rate, D discount rate, and N plant life	1.17	1.17	1.11	1.26	(b)
MBTU	= Cost of fossil fuel used to generate replacement electrical energy ($/MBTU)	1.90	1.90	1.20	2.00	L
N	= Plant book life (years)	30	30	30	30	--
OILBTU	= Cost of fuel oil ($/MBTU)	5.00	5.00	4.75	5.25	Linear
PLTREP	= Plant repair/recommission cost ($ x 10^6)	Accident dependent - see Section 7				
VAROM	= Variable portion of O&M costs [MILLS/KW(t)-HR]	0.1	0.1	0.1	0.1	--
YR	= Outage period of plant (years)	Accident dependent - see Section 7				

(a) Basis of Single Value Estimate: 2240 MW(t) HTGR-SC/C, Equilibrium Plant, 2005 startup, LEU/Th once-through fuel cycle, TMI-2 type accident scenario, utility HTGR and electric backup plant ownership, industrial ownership of steam backup plant and 1983 GCRA groundrules, where applicable.

(b) This variable is a function of the application/accident scenario and/or judgments of PUC actions.

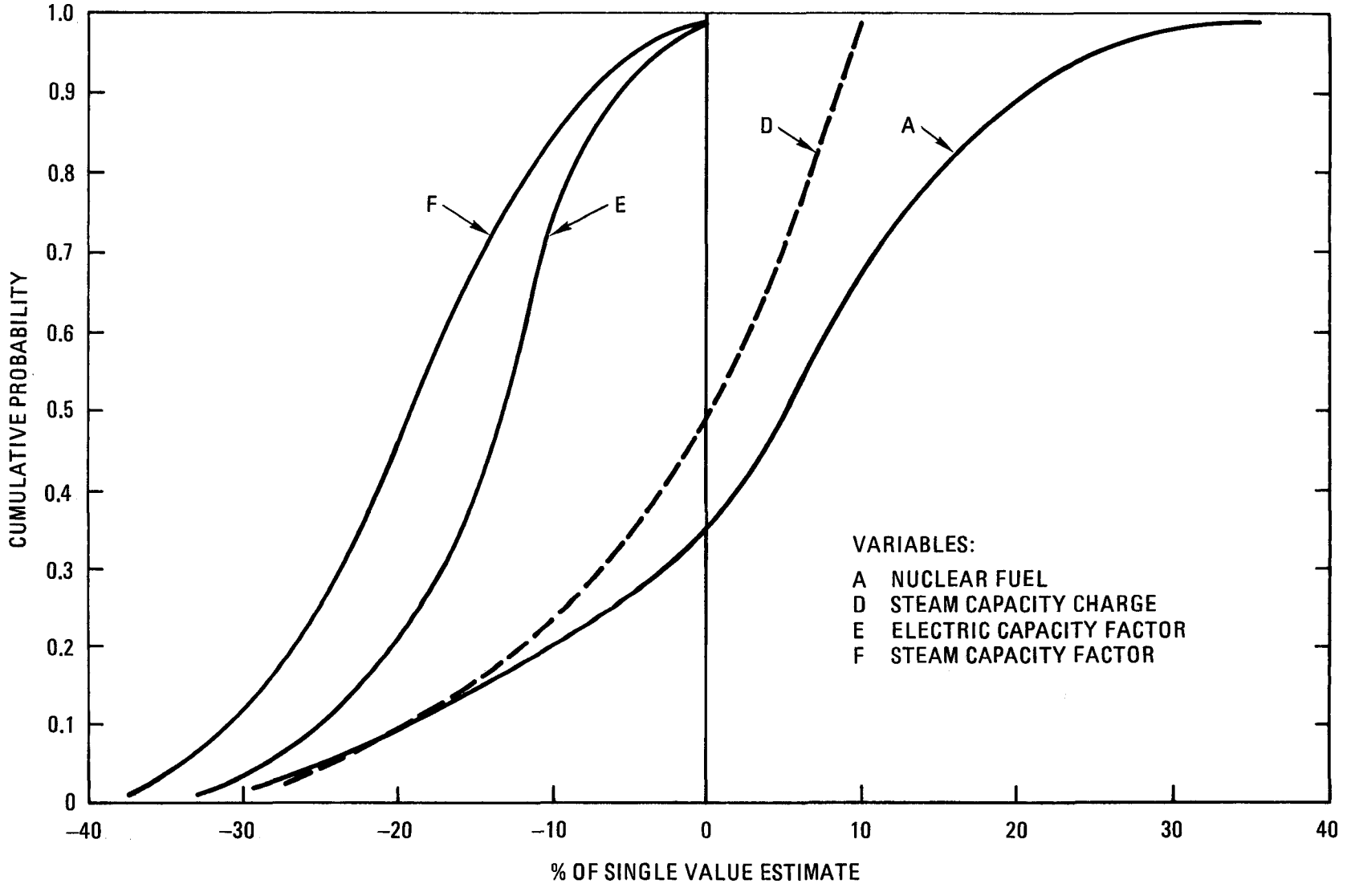

Fig. B-1. Uncertainty distributions for investment risk economic model input variables A, D, E, & F

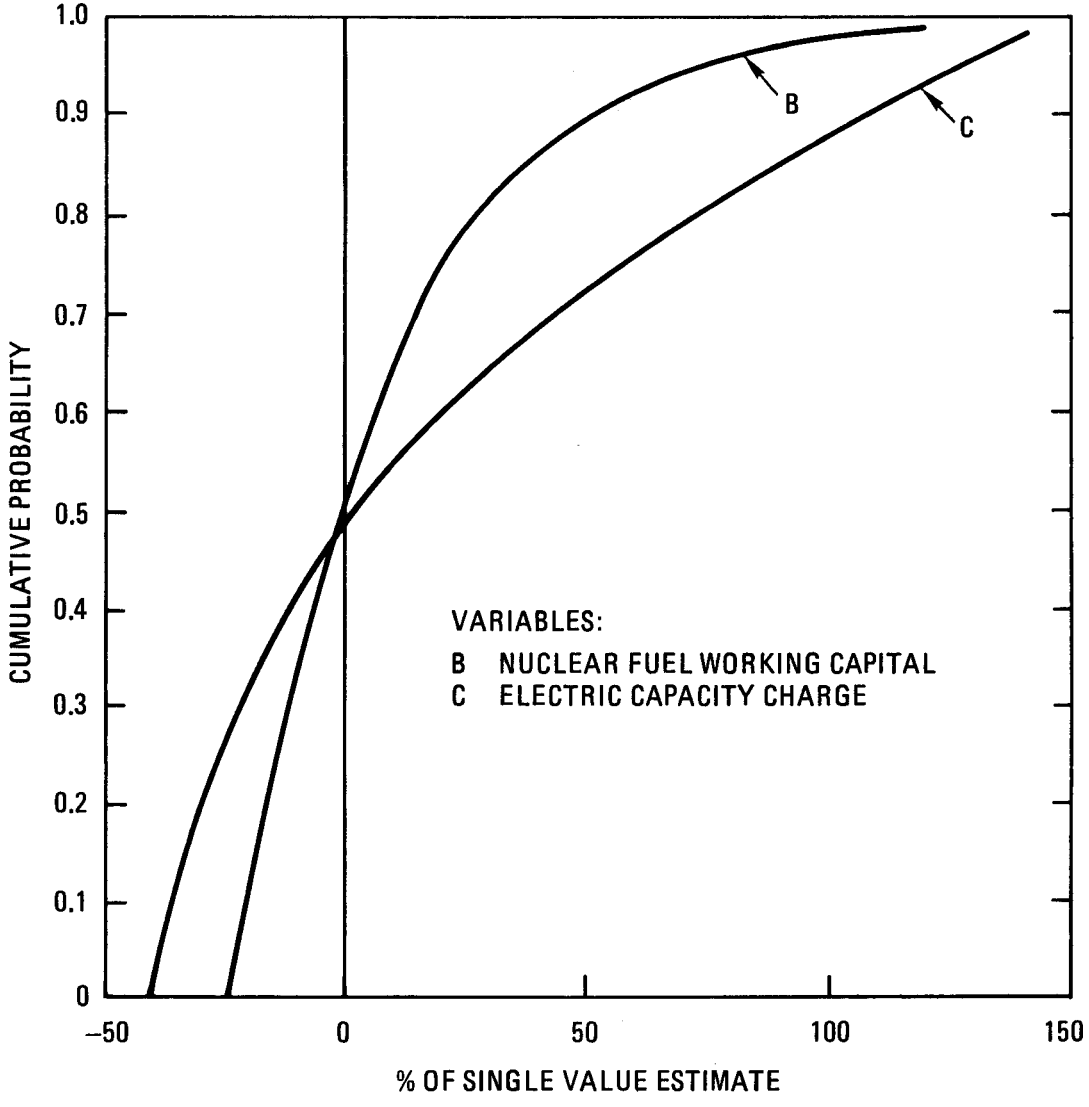

Fig. B-2. Uncertainty distributions for investment risk economic model input variables B & C

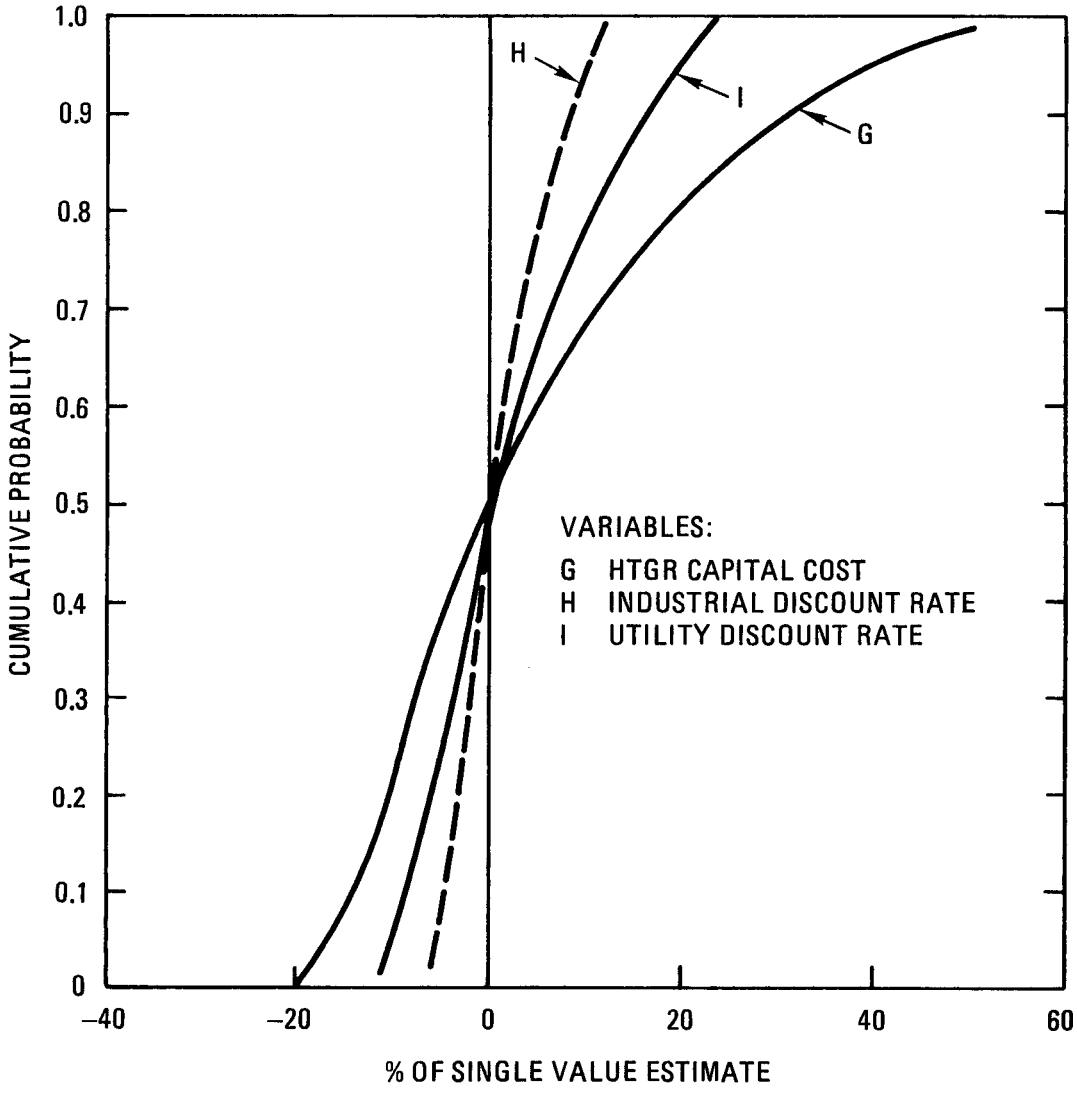

Fig. B-3. Uncertainty distributions for investment risk economic model input variables G, H, & I

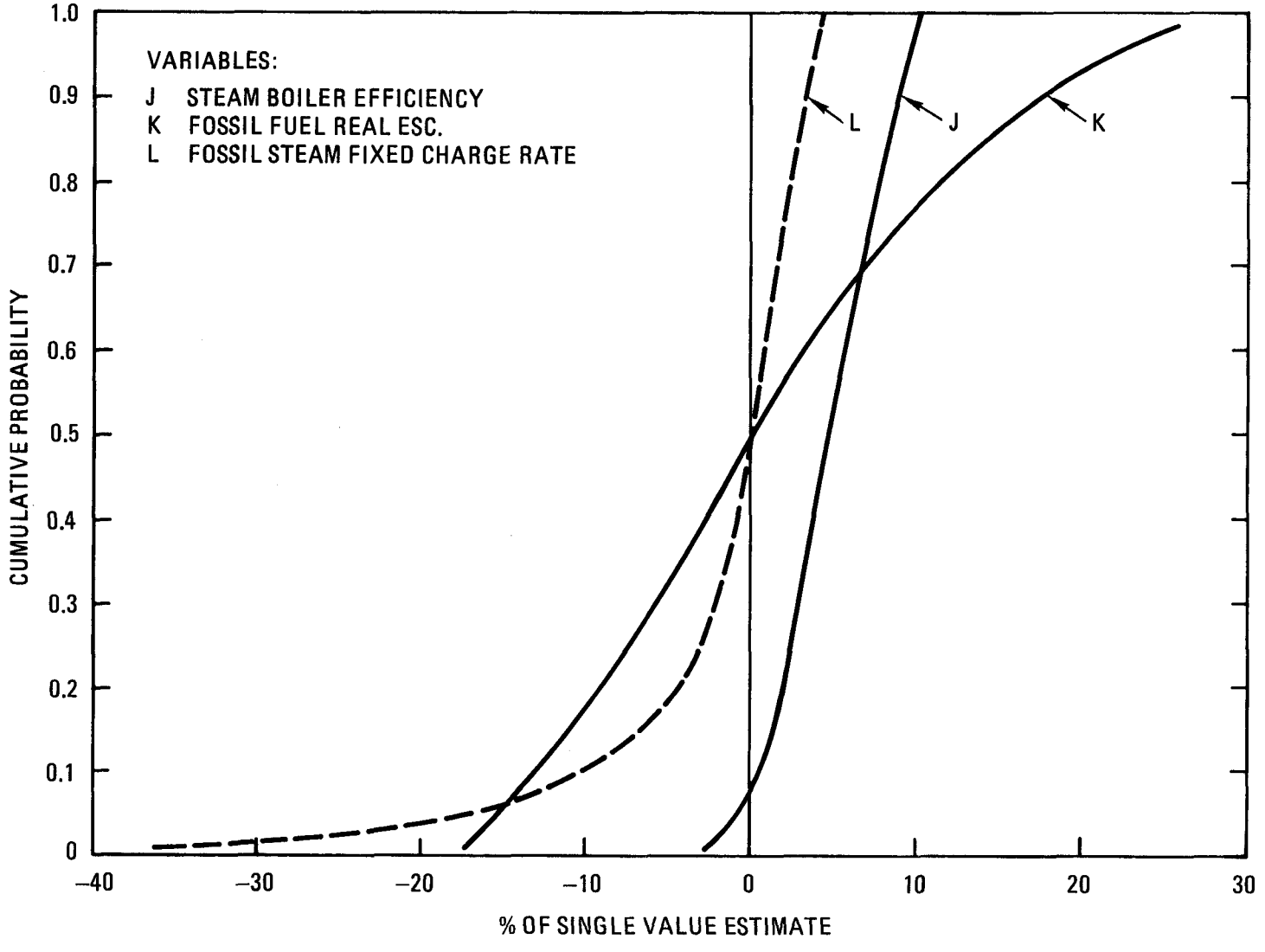

Fig. B-4. Uncertainty distributions for investment risk economic model input variables J, K, & L

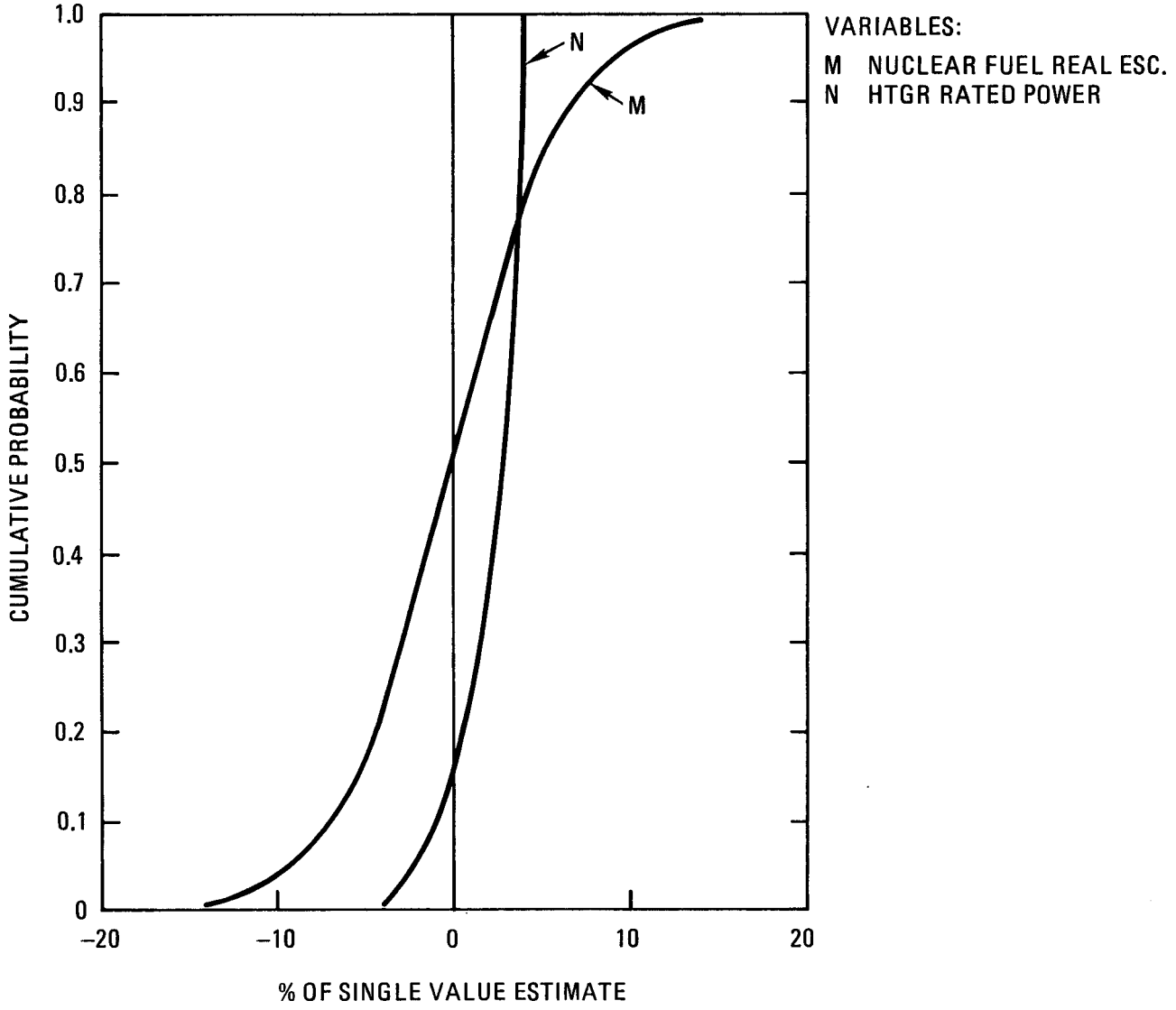

Fig. B-5. Uncertainty distributions for investment risk economic model input variables M & N

cycle type and whether a lead or equilibrium plant. The lead plant value can be about 15% above the base (equilibrium) cost, whereas the HEU/Th recycle fuel type is about 35% below the base (LEU/Th once-through).

This is the compliment of FCWC and, when the plant is disabled, would have no role in the economic analysis.

CAPCOS - The capacity charge for replacement electric power [$/KW(e)] will vary significantly from region to region depending on the specific utility system from which the power is purchased. A low end would represent a system having low capital investment because of the average age of the units (older hydro or nuclear) or due to lower cost plants (oil/gas or coal units). There is a correlation between the capacity charge and energy (fuel) charge; i.e., variables MBTU and OILBTU.

By the time the HTGR is operational, the most likely replacement power unit would be a coal plant having an FGD system. Costs of this plant from the 7/83 EEDB update (Ref. B-3) are $801/KW(e) for a 795 MW(e) plant and $969/KW(e) for a 480 MW(e) plant. The high cost would be a PWR at $1300/KW(e) with a 50% overrun, whereas the low might be older generating capacity or hydro at, say, $500/KW(e). The capacity charge is determined by multiplying by the fixed charge rate, which is ~8.6%/year per GCRA Groundrules (Ref. B-4).

CAPSTM - See CAPCOS for remarks. An additional factor is whether the backup steam plant is owned by a utility or by industry. Therefore, there is a correlation with DI, if used.

The sample values are based on industrial ownership, otherwise this factor would be like CAPCOS reduced by

about 15% due to the elimination of the T/G costs. An industrial backup steam supply system would, no doubt, be an oil/gas unit with a nominal cost of ~$240/KW(t) (using the backup oil plant for the PARAHO study). This must be multiplied by the industrial fixed charge rate, 13.7%/year, per GCRA Groundrules. The cost could be 10% higher or 30% lower (due to use of an older plant).

CF( ) - Capacity factors vary with the type of plant (coal, oil or nuclear) and for the HTGR would depend on whether it is a lead or equilibrium plant. Generally speaking, the values shown in the GCRA Groundrules do not represent nominal operating experience. Should not vary significantly by region.

According to the GCRA Groundrules, the steam production capacity factor is higher than electricity production capacity factor, 80% compared to 75%. This is due to the added unavailability associated with the T/G equipment. While these may be the recommended values for economic analysis, a nuclear power plant has never achieved levels of operation this high over an extended period. Thus, a CF of 65% is assumed until assurance is greater that the HTGR will meet the higher gols.

CONSTR - Capital cost of the damaged HTGR unit depends on unit size (see variable KWTRAT) and whether it is a lead or equilibrium plant. A modest variation, ±2%, could be expected due to labor cost differences at different sites.

From the Baseline "0" cost forecast report (Ref. B-5) and the 1982 Design & Cost report (Ref. B-6), the base cost of the Equilibrium 2240 MW(t) plant is $1321M (1982); to which needs to be added 4% escalation to 1983 dollars,

AFUDC at 4.4%/year, and $43M NSSS cost risk allowance, making the most likely value $1595M, or $712/KW(t). All schedular cost increases will be excluded from this analysis since this is in constant base year dollars. The high value assumes an increase of 50% in both labor and material content, whereas the low value assumes the indirects, which are now 40% of the total cost, will be cut in half if the equilibrium plant will be standardized.

D( ) - The discount rate will vary with individual owner financing, whether utility or industrial, and if utility, whether public or investor owned. Therefore, this variable is site dependent.

The GCRA Groundrules show the constant dollar discount rate to be 4.4% for utility financing and 8.5% for industrial financing. It is not unreasonable to assume that these values could increase by 1% and decrease by 1/2%.

EBOIL - Boiler efficiencies depend on the type of fossil unit used, oil/gas or coal, and if coal, whether it employs standard combustion or a fluidized bed.

An oil fired backup steam unit is assumed. The GCRA boiler efficiency for this type of unit is 82%. Engineering judgment is that a modern oil fired boiler should have an efficiency equal to standard coal, 88%. Perhaps some older units would have a slightly lower efficiency, say 80%.

ESCAA - A forecast of the real escalation of nuclear fuel which reflects the increased value of uranium and electricity above that of the general economy inflation.

The nuclear fuel cycle costs, FCC, are already levelized over 30 years and incorporate real escalation to the startup year 2005. Whereas the real escalation of yellowcake is expected to be 4%/year through 1995 and 2.5% from 1995 to 2005, the enrichment services (which are not shown to escalate) could in fact be reduced in cost due to the bringing on-line of the centrifugal enrichment facility. As a result, the uranium real escalation may be somewhat lower than provided in the GCRA Groundrules.

The fuel cycle engineering group feels these changes in real value of the uranium costs could affect the depletion portion of costs (70% of total) by ±50% by the year 2005. This would be ±35% on the total fuel cost of ±1.4%/year real escalation.

ESCAB - O&M costs are primarily fixed and contain mostly labor costs followed by materials and supplies, insurance and off-site services.

GCRA Groundrules provide for no real O&M escalation. Since the labor and other costs do not contain unique items, it is expected that these costs will follow those of the general inflation trend.

ESCAD - A forecast of the real escalation of coal, oil, or gas fuels which exceeds the general economy inflation.

The GCRA Groundrules show about a 3%/year real escalation for coal between 1983 and 1995 followed by a 1.5%/year rate through 2005. Oil and gas have a 4%/year rate from 1983 through 1995 followed by a 1.5%/year rate through 2005.

Coal would probably be the fuel used to generate replacement electrical power and, thus, the composite rate between 1883 and 2005 is 2.3%/year, for the weighted USA average, the variation shown is the forecast for the regional coal cost extremes. A more direct approach would be to use the fuel cost forecast for the year 2005 provided in the GCRA Groundrules.

ESCAE - Plant repair costs are composed mainly of labor and purchased equipment.

GCRA forecasts constructions costs to follow the overall economic inflation. This would hold true for the repair costs as well.

ESCBC - See ESCAD for remarks.

A forecast 4%/year real inflation between 1983 and 1995 is given in the GCRA Groundrules, changing to 1.5%/year between 1995 and 2005. This gives a composite rate of 2.9%/year from 1983 to 2005.

Again, a more direct approach would be to use the oil cost forecast for the year 2005 provided in the GCRA Groundrules.

The range shown assumes that the composite forecast varies by ±0.5%/year.

FACCAP - The plant will either be in or out of the rate base in its entirety. This determination will be made by the controlling PUC and will be based on such factors as: severity of accident and forecast time to recovery, frequency of rate heatings, consumer advocate actions, etc.

For a severe, TMI-2 type accident, it is assumed the plant is removed from the rate base since the PUC realizes the plant will be disabled for a long time.

FACENG - This value will depend on the controlling PUC and the degree to which the ratepayers are protected from rate increases at the expense of the utility investors. Compensation for replacement power energy would be limited to a fractional amount unless nuclear fuel cycle costs were removed from the rate structure.

The amount recovered for replacement capacity charge, FACREP, goes hand-in-hand with the amount recovered for replacement energy. The compensation fraction assumed in the example will, when added to the FACREP, recover only the amount of revenue which was previously being charged the ratepayers for the HTGR operation, over the period of time the plant is disabled. The ratepayers would have been paying approximately 36 mills/KW-hr for the capital charges and fuel parts of the produced electricity or $111.2M/yr. This is 75% of the cost of generating the electric power with a coal plant.

FACFCC - Again the PUC will make this determination based on factors described in FACCAP. If the fuel has been damaged in the accident, the core will be replaced and the fuel cycle removed from the rate structure. If the fuel is not damaged, the situation is more uncertain, where possibly the working capital costs may be left in the rates.

FACFUL - The portion of nuclear fuel replacement costs which may be allowed by the PUC is that part which is not covered by property insurance and, as such, is combined with FACPLT for this determination. This really becomes a

rebate to the owner for the write-off of the damaged core, since the new core costs will automatically be in the rate base when the plant is restarted.

For the TMI-2 type scenario the PUC would not allow recovery of core losses from the ratepayers. In the base case they may allow recovery of that portion of the loss not covered by income tax credits, a maximum of 50% of the loss (i.e., that part not covered by insurance benefits).

FACOM - O&M costs are mainly fixed and will, for the most part, continue while the disabled plant is being repaired. The insurance companies will be careful to segregate cleanup/repair costs from normal plant costs.

The total plant O&M costs are about $41M/year of which 55% (~$23M/year) is associated with production of electrical power. The PUC would allow this amount in the rate structure, thus maintaining the charges to the ratepayers unchanged due to the accident.

FACPLT - See FACFUL remarks. If the PUC allowed a rate base adjustment, this added capital investment would be recovered as part of the annual fixed charges when the plant was restored to service.

However, for the example accident scenario, the PUC at best would only allow recovery of the part of the loss not covered by income tax credits (as discussed for FACFUL).

FACREP - Again, compensation will depend on the controlling PUC and to what extent the ratepayers are protected from rate increases. Compensation of this variable will be in

conjunction with FACENG. Also, the likelihood is that the disabled nuclear plant will be taken out of the rate base before the owner receives this compensation.

FACSTE - Normally the backup steam supply would be owned by the process industry (particularly in the industrial repowering sites). The PUC would not compensate the HTGR owner for this cost under the assumptions made for this example. At best the PUC would allow the recovery of charges equivalent to those of generating steam with the HTGR; i.e., 75% as discussed under FACENG.

FCC - This is the total nuclear fuel cycle cost including work capital charges. See comments under BURN.

Per GCRA Groundrules = $1.33/MBTU, in January 1983 dollars levelized 30 years for a 2005 startup.

Lead plant costs are $1.51/MBTU, whereas the equilibrium plant having HEU/Th recycle fuel would cost $1.02/MBTU.

There is probably a -10%, +20% range on these values. Assume a 10% chance that costs above the nominal high extreme (1.33 x 1.2) would exist, and a 20% chance that costs below the nominal low extreme (1.33 x 0.90) would occur.

FCR - Normal capital charge rate which includes the return on debt and equity as well as property taxes, income taxes and depreciation. The specific rate depends on ownership of the plant.

The GCRA Groundrules value is shown and varies ±5% in keeping with the variation assumed for DU.

FULRUP - The delivery price of the replacement nuclear fuel core would vary with the fuel cycle type, whether a lead or equilibrium plant and with the cost of uranium and manufacture.

An equilibrium plant replacement core is shown for the most likely and, also, for the low (a HEU/Th recycle core would cost essentially the same). The high value is a lead plant core escalated to 2005.

HTRATE - When divided into the conversion factor 3413 BTU/ KW(t)-HR, the plant cycle efficiency is obtained. Thus, the heat rate varies inversely with the cycle efficiency and depends on the type and age of the electric generating station.

In the year 2005, it is assumed that the replacement power coal plant will have a regenerative FGD system and conventional combustion as described in TAGs (Ref. B-7). The low is an advanced pulverized coal unit with 4500 psi steam pressure.

KWE - That portion of the HTGR-SC/C output in electricity. Can range within the guidelines of a cogenerator.

The value shown provides a rather high electric output yet the corresponding steam to process plant is over 60% of the HTGR thermal energy. A low value represents a process that demands nearly all (95%) of the thermal energy, whereas high is a 50-50 split of thermal energy between process steam and electricity generation.

KWT - The compliment of KW(e): The most likely value is for 470 MW(e) generation, the low for 635 MW(e) generation and the high for 64 MW(e).

KWTRAT - The thermal power rating is a fixed value for a specific plant.

The values shown are calculated by System Engineering incorporating the margins of components contributing to the thermal performance.

LAT - Values for this variable depend on whether the plant is the lead or equilibrium case.

The earliest a lead plant could become operational is about 15 years from now, whereas there would realistically be another 15 years before the equilibrium plant went on-line.

LFAA - Varies with the appropriate real escalation rate, plant ownership (D) and the book life of the plant (N). Therefore, this variable is site dependent.

The GCRA Groundrules do not provide a separate levelization factor for the nuclear fuel. FCC is already provided in 30-year levelized dollars and incorporates real escalation to the year 2005. Therefore, the 2005 FCC value should be used directly.

LFAB - See LFAA comments. The "zero inflation" levelization factor given by GCRA is 1.0 and is not expected to vary since there is no real escalation (per ESCAB discussion).

LFAD - See LFAA comments. The levelization factor is shown as higher (about 7%) for the Inter-Mountain region than other U.S. areas by the GCRA. Also utility factors are 3-6% above industry factors. Other variables are the uncertainty in real escalation of coal costs and in the financing discount rate.

LFAE - See LFAB comments.

LFBC - See LFAA comments. The GCRA factor for industrial ownership is shown as the most likely value, in keeping with the example scenario. The utility ownership factor is 3% higher and the variation due to uncertainty in real escalation and discount rate would add ±5% to the range.

MBTU - Fossil fuel cost depends on whether it is oil/gas or coal. If coal, it is further dependent on type (anthracite, bituminous or subituminous) and location of the mine (i.e., shipping costs). Thus, it can be highly site dependent.

N - The plant book life is a constant which is used for the basis of economic calculations and comparisons.

OILBTU - Oil costs are generally not sensitive to region. The GCRA Groundrules shows $5.00/MBTU for fuel oil independent or region. However, it's reasonable to assume a ±5% variation for factors such as distribution and market conditions.

PLTREP - The cost of repairing and recommissioning the damaged nuclear plant varies significantly depending upon the nature of the accident. For a given accident there may be varying amounts of damage combined with an uncertainty in the costs of cleanup and restoring the plant to operation. Site variations should be small. The insurance company will be careful to segregate these costs from post accident upgrade costs due to NRC actions.

The example assumption for a severe TMI-2 type accident is a cost of $1.2 billion to restore the plant to operation. It's assumed that the types of accidents to be considered fall within the $50 to $2000 million range.

VAROM - A minor portion of the annual O&M costs which vary with the power generated by the plant within the period. The GCRA value is shown.

YR - This is a direct consequence of the severity of the accident and the period of time necessary to restore operation. The worst case would be a decommissioned plant.

REFERENCES

B-1. Long, J. D., "Nuclear Property Insurance, Status and Outlook," NUREG-0891, May 1982.

B-2. Koch, P. K., and H. E. St. John, "STADIC-2 A Computer Program for Combining Probability Distributions," GA Technologies Report GA-A16227, July 1983.

B-3. "Phase V Update Report for the Energy Economic Data Base Program," Unit Engineers and Constructors, Report DOE/NE-0051, July 1983.

B-4. "Economic Groundrules for the HTGR Program in 1983," GCRA-3-008, April 29, 1983.

B-5. "2240 MW(t) HTGR-SC/C Design and Cost Report," GA Technologies Co., PC-000040, May 1982.

B-6. "Balance of Plant Design and Cost Report," United Engineers and Company, UE&C/GCRA-33029, June 1982.

APPENDIX C
DATA BASE FOR ASSESSMENT AGAINST DOE GOAL

This appendix and in particular Table C-1 provides in summary form the data points on which the assessment curve seen on Fig. 8-3 was based. The data itself comes from either this investment risk assessment or the availability assessment in Ref. C-1. A brief explanation of the table is given below.

Column 1 is a list of outage contributors. When the source is the investment risk assessment the contributor is noted by its consequence category designation. When the source is Ref. C-1 the contributor is noted by its system name. The list is ordered by mean outage duration given that an outage occurs.

Column 2 lists the mean outage duration for the various outage contributors.

Column 3 lists the mean frequency of occurrence for the various outage contributors. For contributors identified in the investment risk assessment this is given explicitly elsewhere in the text. For the contributors in Ref. C-1 it is approximated as the reciprocal of the sum of the mean time between failure (MTBF) and mean time to repair (MTTR), i.e.,

$$\bar{\lambda} = \frac{1}{\text{MTBF} + \text{MTTR}}$$

Column 4 is the average number of outage days per year resulting from each contributor. This is the product of columns 2 and 3.

TABLE C-1
COMPILATION OF RESULTS FOR COMPARISON WITH DOE-HTGR
INVESTMENT PROTECTION (SEE FIG. 8.3) GOAL

Outage Contributor	Outage Time (days)	Frequency (per year)	Cumulative Average Outage Rate (days per year)	
DC-1	1825	$3.8(10^{-5})$	0.069	0.069
LC-1.b	1825	$2.7(10^{-6})$	0.0049	0.0739
DC-2	1095	$8.5(10^{-6})$	0.009	0.0829
DC-3	912	$3.8(10^{-6})$	0.0035	0.0864
DC-4	912	$1.4(10^{-5})$	0.013	0.0994
DC-5	791	$3.4(10^{-6})$	0.0027	0.102
LC-1.a	669	$2.5(10^{-6})$	0.0017	0.104
DC-7	487	$3.7(10^{-5})$	0.018	0.122
TG-3	363	$1.0(10^{-4})$	0.036	0.158
SA-5	316	$2.1(10^{-6})$	0.001	0.159
FE-1	231	$5(10^{-6})$	0.0012	0.16
SA-4	182	$1.2(10^{-5})$	0.002	0.162
PC-1	128	$2.4(10^{-5})$	0.003	0.165
TG-2	117	$3(10^{-3})$	0.351	0.5162
LC-2	91	$2.8(10^{-3})$	0.255	0.771
Reactor int. components/100%	83	$5(10^{-4})$	0.0334	0.805
RI-2	73	$1.0(10^{-5})$	0.001	0.806
SA-3	70	$3.8(10^{-5})$	0.003	0.809
DC-8	61	$7.0(10^{-6})$	0.0004	0.809
SA-2	40	$1.4(10^{-4})$	0.006	0.815
PC-2	30	$2.9(10^{-2})$	0.882	1.697
Reactor core/100%	30	0.0336	0.806	2.50
TG-1	26.2	$2.0(10^{-2})$	0.524	3.03
Heat exchanger/100%	21.9	0.417	7.29	10.3
PC-3	18	0.42	7.56	17.9
DC-9	15.2	$4(10^{-4})$	$6.08(10^{-3})$	17.9
Building structure technical service system	6.5	0.0394	0.205	18.1

TABLE C-1 (Continued)

Outage Contributor	Outage Time (days)	Frequency (per year)	Cumulative Average Outage Rate (days per year)	
Main circulator/100%	5.5	0.358	1.59	19.7
Emergency power system/100%	5.5	0.0595	0.262	19.9
Auxiliary circulator/100%				
Auxiliary heat exchanger/100%	5.4	0.184	0.799	20.7
Auxiliary heat removal control/100%				
Turbine-generator and accessories generator/100%	5	1.46	5.84	26.8
Containment isolation/100%	4.58	0.0225	0.0823	26.9
Neutron and region flow control/100%	4.58	0.323	1.18	28.0
Main generator transformer/100%	4.5	0.206	0.74	28.8
RI-1	3.04	0.2	0.608	29.4
Feedwater heaters/100%	2.5	0.226	0.452	29.8
Turbine generator and accessories-turbine/100%	2.5	3.67	7.34	37.2
Helium services/100%	2.29	0.38	0.697	37.8
Nuclear service water/100%	2.29	0.0461	0.0845	38.0
Auxiliary cooling water/100%	2.08	0.0186	0.0311	38.0
SA-1	2.04	$5.0(10^{-4})$	0.001	38.0
All other nsss systems/100%	2.0	0.496	0.794	38.8
Turbine-generator and accessories-generator/33.3%	1.67	0.964	1.28	40.1
Service water pump/100%	1.5	0.024	0.036	40.1
Turbine building closed cooling water/100%	1.5	0.0333	0.0399	40.1
Auxiliary transformer/100%	1.5	0.0482	0.116	40.3
Auxiliary cooling water/50%	1.33	0.0515	0.0548	40.3
Liquid nitrogen/100%	1.25	0.175	0.175	40.5
Auxiliary circulator motor cooling/100%	1.125	0.00115	0.00104	40.5

TABLE C-1 (Continued)

Outage Contributor	Outage Time (days)	Frequency (per year)	Cumulative Average Outage Rate (days per year)	
Reactor plant cooling water/100%	1.0	0.0515	0.0412	40.5
Moisture monitor/100%		0.0417	0.0334	40.6
Condensate pumps/100%	1.0	0.105	0.0841	40.6
Condensate pumps/50%	1.0	0.472	0.378	41.0
Feedwater pumps/50%	1.0	0.0963	0.0771	41.1
Other feedwater components/100%	1.0	1.09	0.873	42.0
Main turbine-condenser/100%	1.0	1.57	1.26	43.2
Secondary turbine-turbine/33%	1.0	2.99	2.39	45.6
Circulating water/100%	1.0	0.257	0.206	45.8
Overall station electrical distribution/100%	1.0	0.28	0.224	46.1
Uninterruptible power distribution/100%	1.0	0.28	0.224	46.3
Steam piping/100%	0.75	0.481	0.289	46.6
Main steam isolation valve/100%	0.75	0.21	0.126	47.7
Feedwater pumps/100%	0.75	0.962	0.577	48.3
Auxiliary boiler + steam/100%	0.75	0.14	0.0841	48.4
Instrument service air/100%	0.75	0.28	0.168	48.5
Auxiliary circulator motor coding/50%	0.667	0.0101	0.00537	48.5
Engineered safety features actuation/100%	0.667	0.324	0.173	48.7
Main circulator/50%	0.583	0.092	0.0429	48.8
Main circulator/25%	0.583	4.46	2.08	50.8
Gaseous radioactive waste management/100%	0.5	0.209	0.0834	50.9
NSSS protection/100%	0.5	0.911	0.365	51.3
Special safety related/100%	0.5	0.0796	0.0318	51.3
All other nsss systems/25%	0.5	1.99	0.794	52.1
Condensate polisher/100%	0.5	0.209	0.0834	52.2
Feedwater pumps/25%	0.5	1.49	0.595	52.8
Circulating water/25%	0.5	1.35	0.54	53.3

TABLE C-1 (Continued)

Outage Contributor	Outage Time (days)	Frequency (per year)	Cumulative Average Outage Rate (days per year)	
NSSS control/100%	0.5	1.12	0.449	53.8
BOP control/100%	0.5	1.22	0.49	54.3
Plant data acquisition and processing/100%	0.5	0.209	0.0834	54.3
Secondary turbine-condenser/33%	0.333	3.15	0.841	55.2
Plant reactor cooling water/50%	0.3125	0.144	0.0359	55.2
NSSS protection/25%	0.125	3.65	0.365	55.6

Column 5 is the accumulated number of outage days per year for all outage causes with an outage duration greater than or equal to the contributor listed in column 1. For any row in the table column 5 is a summation of column 4 down to and including that row.

REFERENCE

C-1. "HTGR-SC/C Lead Plant Availability/Reliability Assessment Report," Bechtel Group Inc., May 1984.