Indian Point Probabilistic Safety Study

Overview and Highlights

Power Authority of the State of New York
Consolidated Edison Company of New York, Inc.

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INTRODUCTION

In the past decade, society has grown increasingly aware of the direct and indirect risks that can accompany technological advancements. This awareness has led to new laws, new regulations, and new scientific methods for measuring technological risks. These new techniques attempt to quantify the two elements that make up "risks": the likelihood of the damage occurring and the magnitude of any potential damage—or in risk assessment terms, the "probabilities" and the "consequences." These two components of risk—probabilities and consequences—cannot be separated; both are essential to decisions about benefits and the relative merits of alternative courses of action. By calculating both components of technological risk as precisely as possible, society can more knowledgeably compare the relative risks of competing technologies. Then, the risk of a technology in comparison to its benefits can be examined.

The energy production industries, particularly nuclear power, have been at the forefront of these advances in risk assessment. Nuclear power has adopted an advanced, sophisticated approach in detecting and measuring risks which has furthered our understanding of nuclear power plant safety. When all other forms of energy are similarly evaluated, a truer picture of the tradeoffs in energy decisions will emerge.

The purpose of this overview is to present some of the highlights of an extensive safety study performed on Indian Point Units 2 & 3. Since the study is a state-of-the-art investigation using sophisticated scientific tools, this overview provides some perspective for the general readership. It includes a discussion of nuclear power plant safety features and reactor safety analyses. Then, it describes a methodology called "probabilistic risk assessment" (PRA) followed by highlights of the Indian Point Probabilistic Safety Study.

NUCLEAR POWER PLANT SAFETY

In decisions to license, build, and operate all nuclear power plants, the issue of safety dominates. Operators of nuclear power plants must demonstrate to the Nuclear Regulatory Commission (NRC)—the independent Federal agency responsible for licensing and regulating nuclear facilities—that each plant is designed and constructed with adequate safety features. Most of these safety features have one overall objective: to prevent or minimize accidents which can result in offsite radiation exposure or release of radioactive material from the plant.

Reactor Design Features

Several physical barriers to prevent radioactive materials from escaping to the environment are designed into every nuclear power plant. They include:

- *Fuel Rods*. The tubes, or fuel rods which hold uranium fuel pellets, are made of a strong alloy called zircaloy which helps prevent the contained solids and gases from spreading through the reactor coolant system.
- *Reactor Vessel*. Surrounding the core of fuel rods is a reactor vessel some 8 inches thick manufactured of alloy steel to the most rigorous standards and lined with stainless steel.
- *Containment Building*. The reactor and its coolant system are surrounded by a massive concrete and steel building which is specially designed to prevent radioactive materials from reaching the environment in the event that piping systems should leak or break. The concrete in the containment is typically some 3 feet thick and lined with welded steel plate.

In addition to these physical safety barriers, nuclear power plants are designed and built with multiple and diverse safety systems. Outside the plant and at the site boundary, sensitive monitoring and surveillance instruments are installed to detect radiation releases.

Scientists are able to detect and measure radiation even in minute amounts better than virtually any other substance known to man. According to the Committee on the Biological Effects of Ionizing Radiation (BEIR) of the National Academy of Sciences, the average American receives about 100 millirems (a millirem—or one-thousandth of a rem—is a standard unit of radiation dose measurement) each year from background radiation. Natural background radiation comes from the sun, minerals in the earth, and other naturally radioactive elements in the air and in our food. Nuclear power plants and related activities contribute on the average only 0.3 millirems each year to natural background radiation levels under normal operating conditions.

Nonetheless, an accidental release of radioactive materials to the environment with higher exposure levels remains a remote possibility. Because this potential impact upon public health and safety exists at all, emergency plans have been developed and studies are done to continually improve the safety systems in nuclear power plants.

Reactor Safety Studies

Safety analyses are performed for every nuclear power plant before it begins operating. These analyses determine whether the plant owners and operators have taken the appropriate precautions for safe operation of the plants. The techniques for conducting these studies have been refined over the years as the nuclear industry gains more experience. These refinements and improvements are made possible by a growing body of information about the performance of the designed safety features, the reliability of components, and the adequacy of safety margins for different systems and components. Further refinements are made possible by advances in computer technology—the ability to process and analyze large quantities of information to the smallest detail—and in the analytical techniques used by scientists to unravel complicated series of events and to estimate the impacts of those events.

From the early days of the nuclear industry—more than 25 years ago and 1,500 operating years of experience worldwide—safety thinking centered around the multiple-barrier

approach: the physical layers of protection (such as the containment) and the series of backup safety systems (such as emergency core cooling) in case the primary system should malfunction. This safety concept is termed "defense in depth."

Observing "defense in depth" guidelines led to design requirements for nuclear plants that included hypothetical problems called design basis accidents and maximum hypothetical accidents. Engineers had to consider what damage could be caused by, for example, a loss of coolant to the reactor vessel, an earthquake, an airplane crash, a fire or pump failure. They then designed the different parts of the plant to withstand such accidents if these events were to occur.

Since physical simulation of each hypothetical accident is not feasible, additional calculations were made for the most serious possible damages to the plant. These "upper bounding" calculations helped ensure that the best engineering judgments about safety—for example, how much stress a piping system could take in the event of an earthquake—incorporated extra safety margins.

The "defense in depth" philosophy has served the cause of nuclear safety well. Carried to an extreme, however, it can be counterproductive. The introduction of unnecessary complexity could cause a net reduction in safety instead of the expected increase in levels of protection.

Therefore, with the accumulation of a substantial body of nuclear operating experience, scientists determined that tools other than "upper bounding" calculations were needed to make more accurate and realistic safety decisions about nuclear power plants.

Leaders in the field began to look at some of the new scientific tools that other industries—aerospace and defense, for example—were developing to deal with their own questions about safety, performance, and the risks involved. These tools seemed to suit many of the same issues that the nuclear industry confronted. Yet much more work needed to be done to achieve the accuracy and realism that the nuclear industry desired. Experts from a number of different fields pooled their knowledge to address the problem: how can we systematically evaluate even the most improbable accidents to determine the risk they could present to public health and welfare?

The Reactor Safety Study, commissioned by the NRC and directed by Dr. Norman C. Rasmussen of the Massachusetts Institute of Technology, was the first comprehensive study of the accident-related risk of nuclear power plants. Published in October 1975 after three years of work, it was the first attempt to quantify the risks resulting from nuclear power plant operation. It enabled a systematic classification of accidents according to their possible frequency and the possible consequences that could result.

The benchmark Reactor Safety Study report was thoroughly reviewed and critiqued by numerous groups in the years following its publication. The Lewis Report, an evaluation performed for the NRC by the Risk Assessment Review Group, contains both praise and criticism for the original study.

According to the Lewis Committee, the Reactor Safety Study was a significant improvement over earlier attempts to calculate the risks of nuclear power. It introduced a workable accident classification scheme and applied the rules of mathematical probability theory in order to quantify risks. It evolved "event tree" and "fault tree" procedures—described later in this report—to quantify the frequencies with which accidents could happen. It also examined a broader range of potential health effects: in addition to expressing risk in terms of injuries and fatalities that could occur immediately following an accident, the Reactor Safety Study considered the delayed effects of an accident by estimating latent fatalities and cancers. The Lewis Committee also criticized the Reactor Safety Study primarily for its lack of an adequate data base on which to perform some of the analyses and the way uncertainties in the results were portrayed.

Advances in reactor safety analysis since the Reactor Safety Study include:

- More extensive operating data and improved methods for handling data, including the treatment of uncertainty.
- Better documentation and models for systems to reflect the interaction of reactor operators and accident conditions.
- More comprehensive treatment of core damage and the response of the containment during an accident.
- More accurate modeling of specific conditions of the plant site, including initiating events.
- Improved methodology for assembling the results and working backwards to specific risk contributors.

The more recent probabilistic safety studies in this country and Europe built on the foundation of the Reactor Safety Study, addressed its criticisms and incorporated these advances. The Indian Point study, in particular, represents the current state of the art.

UNDERSTANDING PROBABILISTIC RISK ASSESSMENT

Probabilistic risk assessment is considered the most advanced way to make practical decisions in a highly technical, complex society where risks cannot be eliminated, but must be controlled. It helps us understand which things are more likely than others to go wrong and provides a framework for deciding what, if anything, should be done about them.

People have sought ways to assess risk for centuries. Examples can be found in the insurance industries, the financial community, and others that deal with consumer protection. The challenge has been to assess risk systematically and to take into account unforeseen circumstances.

PRA allows you to do just that. Any accident can be examined, regardless of its likelihood. Uncertainties are clearly identified in the process. Analyzing "frequencies of

"occurrence" allows you to tag the most important accident scenarios among the many thousands examined. Human errors can be factored into the calculations as can complications unrelated to the accident itself that could change the levels of risk involved.

The use of PRA techniques is not limited to the nuclear industry. Others are already using a number of PRA techniques. That trend is expected to continue, with the nuclear industry in the vanguard.

Simply put, the PRA methodology asks three basic questions:

- What could go wrong?
- How likely is it that this will happen?
- If it happens, what are the consequences?

The answers to those questions help planners and decision-makers to determine what, if anything, should be done to reduce the likelihood that a particular type of accident could happen or to reduce the level of damage that could occur. The answers help isolate the factors that pose the most substantial chance of adversely affecting public health and welfare.

What Could Go Wrong?

In analyzing risk, we are attempting to understand the effects of taking or failing to take a certain course of action. Since an outcome of a course of action involves a whole sequence of events, the term "scenario" is generally used in place of "outcome."

Developing a "scenario" begins with identifying an event that could precipitate an accident. For example, lightning striking the roof of a building could start a fire which destroys the building. The lightning strike is called the "initiating event" or beginning of an accident sequence.

The next step in developing a scenario, after identifying an "initiating event," is to frame a series of questions that ask, "If such-and-such occurs, *what could happen next?*" Two kinds of answers are given in response to the question: one assumes that a safety barrier erected to prevent further damage from the initiating event works; the second answer assumes that the safety barrier fails.

Using our lightning strike analogy, if the lightning strikes the building, it could hit the lightning rod installed on the roof (the safety barrier works) or it could hit another part of the roof, such as an air conditioning unit (the safety barrier fails). If it hits the air conditioning unit, what could happen next? The regulator on the unit could shut itself down because of the power surge (the next safety barrier works) or the regulator could malfunction and cause a small fire to start in the wiring system (safety barrier fails). And so on. The questioning continues in this manner until every sequence of events that could result from the initiating event is identified.

The process of identifying all of the events in a particular sequence, and assuming that a safety barrier either works or fails, is called building an "event tree." In PRA, complete event trees are developed for all conceivable initiating events.

The next step in answering the basic question, "What could go wrong?" is to determine *how* each of the failures in the succession of safety barriers can happen. How, for example, did the fire start in the wiring system? This requires an examination of the subsystem or components that make up the safety barrier in order to identify those factors which could lead to failure of an entire barrier system. The results of investigating how the failures can happen are diagrammed on a "fault tree."

Fault trees are used to determine the likelihood of failure of the safety systems identified in the event tree. In developing the fault trees, consideration is given to component failure, maintenance action, human error, and other causes. Each system is examined in sufficient detail to determine the *frequency* of failures by looking at the reliability of each of the parts involved.

How Likely Is It That This Will Happen?

The likelihood of something going wrong is based on data about a particular element in the fault tree. The data may include, for example, operating records on equipment or systems.

If there is a large amount of such data, the likelihood of success or failure can be calculated with a high degree of certainty, or "confidence." When there is less data, the calculated frequency, or likelihood, is more uncertain.

These uncertainties are described in terms of "probabilities." In the context of this study a confidence level of 90% implies a probability that the parameter in question—frequency of occurrence of a particular event, for example—does not exceed a given value.

PRA studies include a rigorous mathematical assessment of uncertainty. The uncertainty of each element in the analysis is computed and is included in the final result. Thus, the likelihood of an event occurring is expressed in terms of frequency of occurrence *and* the level of confidence regarding the frequency. This format of communicating uncertainty is called the "probability of the frequency of occurrence."

PRA studies may consider literally millions of scenarios and their corresponding probability of the frequency of occurrence. These probabilities are tabulated individually, and the results are usually presented on a graph.

If only one confidence level or "probability level" is used, the results would form one curved line. It is more common to look at several confidence levels:

- The 1 in 10 chance, or 0.10 probability.
- The 5 in 10 chance, or 0.50 probability.
- The 9 in 10 chance or 0.90 probability.

These results are normally compiled on the same graph—three curved lines—and are called a "family of curves." The interval between the top curve and the bottom curve is the "uncertainty band."

To translate these confidence statements into everyday language, consider the frequency at the 0.50 probability level as a "best" estimate and the frequency at 0.90 probability as an "upper bound." Upper bound estimates mean that "it is almost certain that the frequency of occurrence will not exceed this value." For purposes of communication, therefore, discussions of risk assessment results will use statements such as "the *best* estimate of the frequency of this scenario is once every 10,000 years and the *upper bound* is once every 1,000 years."

If It Happens, What Are the Consequences?

The accident consequences of paramount concern are those affecting people's health. Consequences of accidents are evaluated using extensive computer programs to model accident scenarios, the conditions of the region around the site of the accident, population information, and any other relevant factors including protective measures that could offset some of the damage.

The results of the analysis of accident consequences are expressed as "damage levels"; e.g., numbers of injuries, numbers of fatalities. The consequence analysis is combined with the plant and containment analyses to arrive at the "probability of frequency of different levels of damage." The combined results of damage levels with frequency of occurrence are translated in graphic form into risk curves.

The risk curves from a PRA convey considerable information: for example, what is the frequency of accidents resulting in any immediate fatalities, or what is the frequency of accidents resulting in 100 or more injuries. The degree of confidence (probability) with which the result is stated—10%, 50%, or 90%—is also conveyed.

Frequencies of occurrence are not predictions. They are expressions of the collective knowledge and experience of the experts who performed the probabilistic risk assessment. Frequencies of occurrence suggest what the odds (probabilities) are of something actually happening and thus provide a basis for comparisons with other risks.

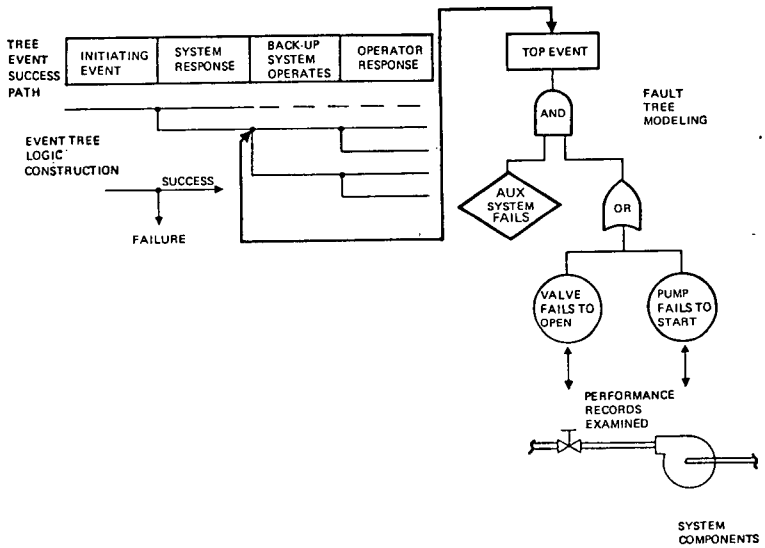
The risk curves link the likelihood that the accident could happen with the potential consequences of an accident. This is the proper way to view risk—probability coupled with consequences.

PROBABILISTIC RISK ASSESSMENT: SOME GRAPHIC ILLUSTRATIONS

The PRA methodology involves a rigorous process that organizes vast amounts of data through highly detailed analyses. The most concise way to display the key steps, the intermediate findings, and the final results is graphically. These are some very simplified examples of what is actually done in a fully developed study.

Quantifying Accident Sequence Probabilities

Event trees diagram what could happen as a result of an initiating event which could lead to an accident. Branches of the tree illustrate the success or failure of the series of safety barriers and frame the answer to the question "what could happen next?" When a failure is identified, it becomes the "top event" in a fault tree analysis. Fault trees trace the failure back to its root causes, primarily using reliability performance information, to determine how the failure occurred.

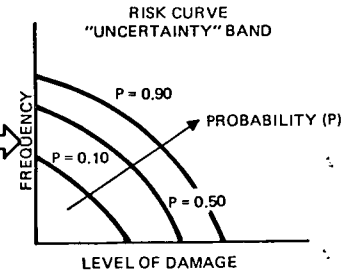


Risk Results

The list of accident scenarios, their likelihood of occurrence (including uncertainty), and their consequences number in the millions in a risk assessment study. After the confidence levels are determined, the computerized list format is translated into risk curves. Levels of damage (or consequences) are expressed in terms of numbers of people affected and the frequency of an accident occurring that could cause that kind of damage. Confidence levels for the results are labeled on the curves lines: 10% probability, 50% probability, and 90% probability. The interval between the 10% curve and the 90% curve is called the "uncertainty band" which shows the minimum and maximum potential consequences of an accident. The information in the scenarios list could be used to add more curves at other confidence levels if it were desired.

SCENARIO	LIKELIHOOD	CONSEQUENCE OR DAMAGE
s_1	$p_1(\phi_1)$	x_1
s_2	$p_2(\phi_2)$	x_2
⋮	⋮	⋮
s_n	$p_n(\phi_n)$	x_n

SCENARIO LIST



THE INDIAN POINT PROBABILISTIC SAFETY STUDY

A comprehensive safety study using PRA techniques was conducted for Indian Point Units 2 & 3, beginning in January 1980. A team of more than 50 experts was involved in the project, including nuclear engineers; systems analysts; probability theorists; mathematicians; risk analysts; computer specialists; experts in thermohydraulics, chemistry, radiological effects, meteorology, seismology and wind; and nuclear power plant operators and designers. This work was reviewed and discussed with an independent review board. The final study report, more than 6,000 pages long, was submitted to the U.S. Nuclear Regulatory Commission in early 1982.

The Indian Point study has two basic purposes:

- To provide a thorough assessment of public risk resulting from the operation of Indian Point.
- To identify the dominant contributors to that risk in terms of plant design and operation. In that connection, the study postulated a variety of equipment malfunctions including progressive failures of multiple engineered safeguards leading to melting of the reactor core and failure of the containment building.

The study team began by collecting extensive information from several sources:

- Specific Indian Point operating data, covering the plant and the site. Plant data included, for example, component performance records, maintenance duration reports, and initiating event analyses. Site data included comprehensive examinations of meteorology, terrain, and demographics.
- Operating data from other nuclear power plants. Numerous data sources were analyzed to establish a comprehensive data base. Sources of data included: (1) Licensee Event Reports and the NRC data summaries of these reports covering diesel generators, pumps, valves, and control rod drives; (2) the IEEE Guide to the Collection and Presentation of Electrical, Electronic, and Sensing Component Reliability Data for Nuclear Power Generating Stations; (3) the Reactor Safety Study; (4) the Nuclear Plant Reliability Data System; (5) the EPRI reports on Frequency of Anticipated Transients; and (6) the Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications.
- Expert judgment on equipment performance and accident initiators. Experts and their resources contributed additional insight and information about equipment performance and specific events that could initiate an accident or alter its course.

These data were examined using the PRA methodology discussed previously. In order to assess the possibility that public health could be endangered by an accident at Indian Point, the study identified accident sequences that could lead to release of harmful levels of radioactivity and isolated the dominant contributors to risk contained in those sequences.

The investigative process was exhaustive:

- Literally hundreds of thousands of accident scenarios were developed using the event tree/fault tree approach. Information about reactor operations and reliability of equipment was incorporated in the scenarios. These event trees and fault trees were used to evaluate various sequences leading to release of radioactivity.
- In order to isolate dominant risk contributors, initiating events from both internal and external causes were analyzed. Internal causes included plant malfunctions called "transients" and failures in heat removal systems such as loss of coolant accidents (LOCA's) which could lead to melting of the reactor core. External causes included earthquakes, fires, high velocity winds, tornadoes, floods, and aircraft accidents. Analyses of initiating events and accident sequences were not limited to hardware concerns; operator interaction with the plant systems and human response under accident conditions were also assessed.
- The response of the reactor core and containment under different core melt conditions was analyzed in extensive detail. The form and state of the damaged core and its interaction with structural materials, air, water, steam, and other reaction products were considered. The progress of core melt conditions was examined carefully; the pressure changes during a core melt and fluctuations in heat loads were quantified to define containment response; and release conditions for radioactive material were identified.
- The region around Indian Point was modeled, including information about population distribution and meteorological conditions. This information helped establish the level of risk which is partially dependent on wind speed and direction, the portions of the surrounding communities potentially affected, dispersion of radioactive material, and the like.
- After the dominant risk contributors were identified, along with their causes and probable frequency of occurrence, estimates were made of the potential damage to public health and safety. These estimates were compiled and displayed graphically as a family of risk curves which indicates the confidence level attached to the estimates.

Public Health Effects

The results of the Indian Point Probabilistic Safety Study focus ultimately on public health effects. The risks to public health discussed in this overview are early, or "acute," fatalities occurring within a short time after exposure, non-fatal radiation injuries due to exposure, thyroid cancers (most of which are treatable and non-fatal), and latent cancer fatalities occurring over a 30-year period. The results are highlighted here for three levels—any effect, 100 effects, and 1,000 effects. In like manner, frequency of occurrence results have been computed for other levels of effects.

The results are also presented as "best" and "upper bound" estimates. By presenting two estimates, this analysis provides a more comprehensive picture of risk than would be the case if only a single health effect, a single level of effect, or a single confidence level were depicted.

Indian Point Unit 2. The most significant health effect, in terms of near-term impact, is acute fatalities. The estimates vary depending on the level of consequences analyzed. The best estimate for any effect is once in 17 million (1.7 million)* years of reactor operation. The best estimates of frequencies of occurrence for 100 and 1,000 effects are once in 100 million (4.8 million) years and once in a billion (29 million) years, respectively.

For radiation injuries, the best estimate for any effect is once in 370,000 (59,000) years. The best estimates for 100 effects are once in 2.9 million (290,000) years, and for 1000 effects once in 110 million (2.9 million) years.

In addition to the immediate health effects of an accident, delayed effects were also examined. For example, the best estimate of any thyroid cancers occuring is once in 2,500 (1,000) years of reactor operation. The best estimates for 100 effects are once in 5,900 (1,400) years and for 1,000 effects once in 12,000 (2,700) years.

Finally, the question of latent cancer fatalities occurring over a 30-year period was investigated. The best estimate for any effect is once in 3,000 (1,000) years. The best estimates for 100 effects are once in 5,000 (1,400) years, and for 1,000 effects once in 10,000 (2,400) years.

Indian Point Unit 3. The results for Indian Point 3 differ somewhat from Unit 2 due to some differences in design and equipment. The best estimate for any acute fatality is once in 83 million (10 million) years. The best estimates for 100 effects are once in 310 million (45 million) years, and once in 6.3 billion (290 million) years for 1,000 effects.

For radiation injuries, the best estimate for any effect is once in 2.6 million (330,000) years. For 100 effects, the best estimate is one in 20 million (2.4 million) years, and for 1,000 effects, the best estimate is once in 310 million (28 million) years.

*The numbers in parentheses are the upper bound estimates.

The best estimate for any latent thyroid cancers occurring is once in 12,000 (3,100) years. The best estimates for 100 effects are once in 63,000 (7,700) years, and for 1,000 effects once in 100,000 (12,000) years.

The best estimate for any latent cancer fatalities occurring over a 30-year period is once in 20,000 (5,000) years. The best estimates for 100 effects are once in 55,000 (8,000) years, and for 1,000 effects once in 100,000 (12,000) years.

The likelihood that an accident would cause any public health consequences is remote. Upper bound estimates indicate that an accident causing any acute fatality is once in 1.7 million years and that an accident resulting in 100 or more latent cancer fatalities is once in 1400 years. Information on accidental fatalities and latent cancer fatalities from *non-nuclear* causes provides some perspective on these potential health effects. For example, every year, based on the national average, there will be at least 100 accidental fatalities within a 10-mile radius of Indian Point and at least 30,000 cancer fatalities within a 50-mile radius of the plant, all unrelated to nuclear power.

The Results in Perspective

The risk assessment for Indian Point identified the elements of an accident that would need to be present for any fatalities to result.

- *The Reactor Core Must Melt.* Coolant must be maintained in the reactor core to avoid fuel damage. Therefore, nuclear plants contain several back-up cooling systems that can be called on to cool the core if the primary system should stop functioning. Only if these "emergency core cooling systems" should fail would some of the fuel rods melt or be damaged, causing a release of fission products into the reactor vessel and reactor coolant system.

  If there should be a core melt, this by no means suggests that there will necessarily be a significant release of radioactivity to the environment outside the plant. The containment structure of a nuclear plant is designed to contain the radioactive material and prevent such releases. A core melt by itself constitutes no real threat to public health and the study indicates that most core melts would be contained without significant release of radioactive material to the environment.

- *The Containment Must Fail or Be Bypassed.* If the containment serves its function, a core melt would only lead to some leakage of radiation around some of the piping passageways that connect the containment with other buildings in the plant. The risk of those small leaks would be of little or no consequence to the public health.

If the containment were to fail, the amount and type of risk to public health would depend upon conditions such as wind speed and direction; how quickly the radioactive "plume" is dispersed; and the effectiveness of protective steps like sheltering or evacuation. The possibility of bypassing the containment was also examined. Out of all accident categories studied for Indian Point, only about 1 in 1,000 core melt accidents leads to a release which could potentially cause any early fatalities.

A study with the scope and level of detail of the Indian Point safety assessment produces an extremely large body of information and results. Thousands of accident scenarios have been identified and their likelihood and consequences discussed. This overview presents only the key findings about public health effects and the safety of Indian Point.

The application of risk assessment to nuclear safety analyses, while adding immeasurably to our understanding of nuclear safety, has perhaps colored our perception of what the risks truly entail. Because comparable assessments have yet to be performed to the same level of detail for other energy sources and other industries, nuclear safety is being weighed in a vacuum.

Risk analyses in one sense may counteract their intended purpose. Events which are beyond reasonable belief tend to assume a degree of reality when they are analyzed in minute detail. Detailed analyses make people aware of possible hazards which in all probability will never result in injury. Ironically, risk analyses may demonstrate that certain risks are exceedingly remote yet fear of those same risks may increase by that very demonstration. The initial perception of "rare and remote" evolves into a growing uneasiness that "something just may happen." On the other hand, far greater risks unrelated to nuclear power may not be viewed with concern simply because they have not been so intensively investigated. Nuclear power—its safety and its risks—should be considered in that context.

104

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105

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PREFACE

This report is a Probabilistic Safety Study of Indian Point Units 2 and 3, owned and operated by the Consolidated Edison Company of New York, Inc., and the Power Authority of the State of New York, respectively. The study includes: a discussion of probabilistic risk assessment methodology; plant, containment and site analyses; an analysis of initiating events including events external to the plant; an identification of the dominant contributors to risk; and a quantitative statement of the level of safety at the Indian Point nuclear power plants.

This study was prepared by Pickard, Lowe & Garrick, Inc., Westinghouse Electric Corporation, and Fauske & Associates under the supervision of the Utilities.

SUMMARY OF CONTENTS

Section 0 - Methodology	Volume 1
Section 1 - Plant Analysis	Volume 1
Section 2 - Containment Response Analysis	Volume 5
Section 3 - Degraded Core Phenomena	Volume 7
Section 4 - Containment Transient Analysis	Volume 8
Section 5 - Source Terms	Volume 9
Section 6 - Site Consequence Analysis	Volume 9
Section 7 - External Events	Volume 10
Section 8 - Results	Volume 12

SECTION 0
METHODOLOGY

TABLE OF CONTENTS

Section		Page
0.1	INTRODUCTION AND PURPOSE	0-1
	PART 1 - DEFINITION OF RISK	0-3
0.2	QUALITATIVE ASPECTS OF THE NOTION OF RISK	0-4
0.2.1	The Distinction Between Risk and Uncertainty	0-4
0.2.2	The Distinction Between Risk and Hazard	0-4
0.3	THE QUANTITATIVE DEFINITION OF RISK (LEVEL ONE)	0-6
0.3.1	The "Set of Triplets" Idea	0-6
0.3.2	Risk Curves	0-7
0.3.3	Comments on the Definition	0-8
0.3.4	Multidimensional Damage	0-9
0.3.5	Completion of the Scenario List	0-10
0.4	PROBABILITY	0-12
0.4.1	The Definition of Probability and the Distinction Between Probability and Frequency	0-12
0.4.2	The Distinction Between Probability and Statistics	0-14
0.4.3	Commentary on the Definitions of Frequency and Probability--an Example	0-14
0.4.4	The Meaning of "The" Probability--Relation to the Philosophical Basis for Risk Assessment	0-15
0.4.5	Two Methods for Discussing Uncertainty: The "Probability of Frequency" Framework	0-15
0.4.6	Reasons for Introducing the Notion of Probability of Frequency	0-16
0.4.7	The Distinction Between Frequency Distributions and Probability Distributions	0-19
0.5	THE LEVEL 2 DEFINITION OF RISK	0-21
0.5.1	Risk Curves in Frequency Format	0-21
0.5.2	Inclusion of Uncertainty	0-22
0.5.3	Set of Triplets Including Uncertainty	0-23
0.5.4	Comments on the Level Two Definition	0-24
0.5.5	"Cutting" the Family of Risk Curves	0-24
	PART 2 - MODELING AND ANALYSIS	0-26
0.6	IDENTIFYING AND STRUCTURING THE SCENARIO LIST	0-27
0.6.1	Identifying Scenarios--Initiating Events and the Master Logic Diagram	0-28
0.6.2	Structuring the List--The Plant Event Tree	0-30

TABLE OF CONTENTS (continued)

Section		Page
0.6.3	The Containment Event Tree	0-31
0.6.4	The Site Model	0-32
0.7	QUANTIFYING EVENT TREES	0-34
0.8	ASSEMBLING THE SCENARIO INFORMATION INTO FINAL RISK CURVES--THE MATRIX VERSION OF EVENT TREES	0-37
0.8.1	The Matrix Formalism	0-37
0.8.2	The Initiating Event Vector and the Master Assembly Equation	0-39
0.8.2.1	Interpretation of Terms in the Master Assembly Equation	0-40
0.8.2.2	Diagonal Forms	0-42
0.8.3	Inclusion of External Events Within the Matrix Assembly Formalism	0-43
0.8.4	Including Uncertainty Within the Matrix Formalism (Using the Level Two Definition of Risk)	0-44
0.8.4.1	Recapitulation	0-44
0.8.4.2	Combining Uncertainties--The DPD Process	0-45
0.8.4.3	Comments on Numerical Aspects	0-45
0.9	DETERMINING SPLIT FRACTIONS FOR THE PLANT TREE	0-47
0.9.1	The Cause Table	0-48
0.9.2	"Causes" Related to Scenarios	0-49
0.9.3	Relation of System Analyses and Event Trees	0-50
0.10	DETERMINING SPLIT FRACTIONS FOR THE CONTAINMENT EVENT TREE	0-52
0.11	ANALYSIS OF RELEASE CONSEQUENCES--THE SITE MODEL	0-53
0.11.1	Consequence Analysis Methodology	0-53
0.11.1.1	Plume Trajectory and Distribution Modeling	0-55
0.11.1.2	Atmospheric Dispersion Models	0-56
0.11.1.3	Computation of Doses and Health Effects	0-58
0.11.2	Site Information	0-60
0.11.2.1	Population Data	0-60
0.11.2.2	Evacuation Data	0-60
0.11.2.3	Meteorological Data	0-62
0.11.2.4	Release Categories	0-62
0.11.2.5	Land Use Information	0-62
0.11.3	Uncertainties	0-64
0.12	PROBABILITY DISTRIBUTIONS--BASIC CONCEPTS	0-65
0.12.1	Distribution Functions	0-65
0.12.2	Discrete Distributions	0-66
0.12.2.1	Binomial	0-66
0.12.2.2	Poisson	0-66

TABLE OF CONTENTS (continued)

Section			Page
	0.12.3	Continuous Distributions	0-66
	0.12.3.1	Normal (Gaussian)	0-66
	0.12.3.2	Lognormal	0-67
	0.12.3.3	Exponential	0-67
	0.12.4	Discrete Approximations to Continuous Distributions	0-68
	0.12.5	Measures of Central Tendency and Dispersion	0-69
	0.12.6	The Lognormal Distribution	0-71
0.13	PROPAGATION OF UNCERTAINTIES, THE METHOD OF MOMENTS, AND THE METHOD OF DISCRETE PROBABILITY DISTRIBUTIONS		0-75
	0.13.1	Combining Probability Distributions, Analytic or Continuous Variable Case	0-75
	0.13.2	The Method of Moments	0-76
	0.13.2.1	Sum of Probability Distributions	0-80
	0.13.2.2	Product of Distributions	0-80
	0.13.3	The Method of Discrete Probability Distributions	0-81
	0.13.3.1	Discrete Probability Distributions	0-81
	0.13.3.2	Probabilistic Addition	0-82
	0.13.3.3	Probabilistic Multiplication	0-83
	0.13.3.4	General Rule of Probability Arithmetic for Binary Operations	0-83
	0.13.4	Probabilistic Functions	0-84
	0.13.5	Further Extensions, Vector and Matrix Valued Variables	0-86
	0.13.6	Comment	0-87
	0.13.7	Nondistributivity of Probabilistic Operations	0-87
	0.13.8	Dependence and Independence	0-88
	0.13.9	Numerical Considerations, the Condensation Operation	0-89
0.14	DATA ANALYSIS (DETERMINING THE FREQUENCY OF ELEMENTAL EVENTS)		0-91
	0.14.1	Types of Information Available	0-91
	0.14.2	One-Stage Application of Bayes' Theorem (Data Specialization)	0-91
	0.14.3	Determining the Prior (or Generic) Distributions	0-93
	0.14.4	Treatment of the Generic Distributions From the RSS	0-94
	0.14.5	Treatment of the Generic Distributions From IEEE STD-500	0-96
	0.14.6	Generic Distributions: Other Sources	0-96
	0.14.7	Two-Stage Application of Bayes' Theorem	0-97
0.15	HUMAN ERROR RATES		0-99
	0.15.1	Basic Human Error Rates	0-99
	0.15.2	Dependence	0-100
	0.15.3	High Stress Situations	0-103

TABLE OF CONTENTS (continued)

Section			Page
0.16	SYSTEM ANALYSIS		0-104
	0.16.1	System Description	0-104
	0.16.2	Logic Model	0-104
	0.16.3	Causes of System Failure	0-107
	0.16.4	System Quantification	0-108
	0.16.5	Pitfalls Resulting From Correlated Variables	0-108
	0.16.6	Errors in Means and Variances Resulting From Use of Lognormal Distributions	0-111
	0.16.7	Expression of System Failure Rates in Terms of Component Failure Rates. The Supercomponent Idea. Necessity for Proper Treatment of Dependency	0-113
	0.16.8	Test and Maintenance Contribution to System Unavailability	0-115
	0.16.8.1	Test Contribution	0-115
	0.16.8.2	Maintenance Contribution	0-116
	0.16.9	Human Error Contributions to System Failure Rate	0-116
	PART 3 - EXTERNAL EVENTS		0-117
0.17	SEISMIC ANALYSIS METHODOLOGY		0-118
	0.17.1	Methodology	0-118
	0.17.2	Seismicity (Step 1)	0-118
	0.17.3	Fragility (Step 2)	0-120
	0.17.4	Plant Logic (Step 3)	0-121
	0.17.5	Initial Assembly (Step 4)	0-122
	0.17.6	Final Assembly (Step 5)	0-122
	0.17.7	Seismic Effects on Containment	0-123
0.18	WIND ANALYSIS METHODOLOGY		0-124
0.19	FIRE ANALYSIS METHODOLOGY		0-125
	0.19.1	Introduction	0-125
	0.19.2	Identification of Critical Areas	0-126
	0.19.3	The Frequency of Fires	0-126
	0.19.4	Fire Growth	0-127
	0.19.5	Fire Suppression	0-128
	0.19.6	Combined Growth and Suppression	0-128
	0.19.7	Accident Sequences	0-128
	0.19.8	Unconditional Frequencies	0-128
0.20	THE "OTHER" CATEGORY--COMPLETENESS AND LIMITATIONS OF RISK ANALYSIS, COMMON CAUSE EVENTS, AND SYSTEM INTERACTIONS		0-129
	0.20.1	Completeness	0-129
	0.20.2	Initiating Event Frequencies	0-130

TABLE OF CONTENTS (continued)

Section			Page
	1.3.6.3	Small LOCA--Event Tree 3 (ET-3) Quantification	1.3-475
	1.3.6.4	Steam Generator Tube Rupture--Event Tree 4 (ET-4) Quantification	1.3-487
	1.3.6.5	Steam Line Break Inside Containment--Event Tree 5 (ET-5) Quantification	1.3-499
	1.3.6.6	Steam Line Break Outside Containment--Event Tree 6 (ET-6) Quantification	1.3-511
	1.3.6.7	Loss of Main Feedwater--Event Tree 7 (ET-7) Quantification	1.3-523
	1.3.6.8	Closure of One Main Steam Isolation Valve--Event Tree 8 (ET-8) Quantification	1.3-535
	1.3.6.9	Loss of Reactor Coolant System Flow--Event Tree 9 (ET-9) Quantification	1.3-547
	1.3.6.10	Core Power Excursion--Event Tree 10 (ET-10) Quantification	1.3-559
	1.3.6.11	Turbine Trip--Event Tree 11 (ET-11) Quantification	1.3-571
	1.3.6.11.1	Turbine Trip Base Case Quantification	1.3-571
	1.3.6.11.2	Turbine Trip--Loss of Offsite Power Quantification	1.3-571
	1.3.6.11.3	Turbine Trip--Loss of Service Water Quantification	1.3-572
	1.3.6.12	Reactor Trip--Event Tree 12 (ET-12) Quantification	1.3-601
	1.3.6.12.1	Reactor Trip Quantification	1.3-601
	1.3.6.12.2	Special Initiating Events That Fail Mitigating Systems By Common Cause	1.3-601
	1.3.6.13	ATWS--Event Tree 13 (ET-13) Quantification	1.3-627
	1.3.6.14	Tabulated Results	1.3-648A-1
	1.3.7	References	1.3-651
	1.3.8	Appendices	1.3-653
	1.3.8.1	Indian Point Unit 2 Loss of Component Cooling Water Due to a Pipe Break	1.3-654
	1.3.8.2	Indian Point Unit 3 Loss of Component Cooling Water Due to a Pipe Break	1.3-662
1.4	ACCIDENT SEQUENCE ANALYSIS RESULTS		1.4-1
	1.4.1	Indian Point 2 Results	1.4-1
	1.4.1.1	The Indian Point 2 Internal Initiating Event Vector, ϕ^I	1.4-1
	1.4.1.2	The Indian Point 2 Internal Event Plant Matrix, M	1.4-2
	1.4.1.3	Dominant Contributors at Indian Point 2	1.4-2
	1.4.2	Indian Point 3 Results	1.4-2
	1.4.2.1	The Indian Point 3 Internal Initiating Event Vector, ϕ^I	1.4.2
	1.4.2.2	The Indian Point 3 Internal Event Plant Matrix, M	1.4-3
	1.4.2.3	Dominant Contributors at Indian Point 3	1.4-3

TABLE OF CONTENTS (continued)

Section			Page
1.5	INDIAN POINT 2 APPENDICES: DATA AND SYSTEMS ANALYSES		1.5-1
	1.5.1	Indian Point Unit 2 Data Analysis	1.5-1
	1.5.1.1	Site Specific Failure Data Base Development	1.5-1
	1.5.1.1.1	Component Failure Data	1.5-1
	1.5.1.1.2	Component Operability Tests and Service Hours Data	1.5-3
	1.5.1.1.3	Component Failure Mode Definition	1.5-7
	1.5.1.1.4	Uncertainty in Site Specific Data	1.5-9
	1.5.1.1.5	Data Base Applicability	1.5-10
	1.5.1.1.6	Plant Specific Component Failure Mode Data Summaries	1.5-10
	1.5.1.2	Generic and Updated Component Failure Data	1.5-55
	1.5.1.3	Generic and Updated Component Maintenance Data	1.5-67
	1.5.1.3.1	Data Base Development Methodology	1.5-67
	1.5.1.3.2	Component Maintenance Prior Distributions	1.5-72
	1.5.1.3.3	Site Specific Component Maintenance Data	1.5-75
	1.5.1.3.4	Specialized Component Maintenance Data	1.5-76
	1.5.1.4	Indian Point 2 Human Error Rates	1.5-121
	1.5.1.4.1	Basic Human Error Rates	1.5-121
	1.5.1.4.2	Dependence	1.5-122
	1.5.1.4.3	High Stress Situations	1.5-125
	1.5.1.5	Initiating Events Discussion and Quantification	1.5-127
	1.5.1.5.1	Initiating Events. Discussion of the Plant Specific and Pressurized Water Reactor (PWR) Population Data	1.5-127
	1.5.1.5.2	Plant Specific Initiating Event Data	1.5-127
	1.5.1.5.3	PWR Population Initiating Event Data	1.5-127
	1.5.1.5.4	Results	1.5-128
	1.5.1.6	References	1.5-151
	1.5.2	Indian Point Unit 2 System Analyses	1.5-153
	1.5.2.1	Introduction	1.5-153
	1.5.2.1.1	Purpose of System Analyses	1.5-153
	1.5.2.1.2	System Description Sources	1.5-154
	1.5.2.1.3	Analysis Procedures	1.5-154
	1.5.2.1.4	Guidelines to Presentations	1.5-156
	1.5.2.2	Electrical, Instrumentation, and Control Systems	1.5-159
	1.5.2.2.1	Indian Point 2 Electric Power System	1.5-159
	1.5.2.2.2	Indian Point 2 Reactor Protection System	1.5-373
	1.5.2.2.3	Indian Point 2 Safeguards Actuation System (Safety Injection and Containment Spray Actuation)	1.5-405
	1.5.2.3	Fluid Systems	1.5-471
	1.5.2.3.1	Indian Point 2 High Pressure Injection System	1.5-471

LIST OF FIGURES

Figure		Page
0.3-1	Risk Curve	0-8
0.3-2	Risk Curve on a Log-Log Scale	0-8
0.3-3	Risk Surface	0-9
0.4-1	Population Variability Curve	0-20
0.4-2	State-of-Knowledge Curve	0-20
0.5-1	Risk Curve in Frequency Format	0-22
0.5-2	Risk Curve in Probability of Frequency Format	0-23
0.5-3	Development of "Cut Curves" from Level Two Family	0-25
0.6-1	Structuring of Scenarios--Relationship of Pinch Points	0-27
0.6-2	Master Logic Tree	0-29
0.6-3	Structuring the Scenario List--The Plant Event Tree	0-30
0.6-4	Containment Event Tree	0-32
0.7-1	Simplified Plant Event Tree Diagram	0-34
0.8-1	Overview of the Assembly Process, Showing Relationships of Pinch Points, Event Trees, Frequency Vectors, and Transition Matrices	0-41
0.9-1	Form of a System Analysis	0-47
0.9-2	Cause Table	0-48
0.9-3	Structuring the Scenario List Scenarios Including System Failure Modes	0-50
0.9-4	Structuring Scenarios	0-51
0.11-1	CRAC and CRACIT Consequence Assessment	0-54
0.11-2	Illustration of Plume Evacuation and Paths on Fine Grid	0-57
0.11-3	Evacuation Vectors	0-61
0.11-4	Indian Point Meteorological Regions	0-63
0.13-1	Probabilistic Input for Deterministic Function F	0-85
0.13-2	Probabilistic Input to Probabilistic Function F	0-86
0.13-3	Series System	0-88
0.16-1	Top Structure of the Fault Tree	0-105
0.16-2	Sample Case of Supercomponents	0-113
0.17-1	Seismicity Curve (Deterministic)	0-118
0.17-2	Family of Seismicity Curves	0-119
0.17-3	Fragility Curve for Typical Component	0-120
0.17-4	Family of Fragility Curves for a Typical Component C	0-122
0.19-1	Example Cable Tray Configuration	0-128

Indian Point Probabilistic Safety Study

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Volume 2

Indian Point Probabilistic Safety Study

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TABLE 1.3.5.5-4

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. __A	Seq.		
SLFC	7.46-6	2,3,5,6	16	MS-1, R-3	7.45-6
SLF	6.05-10	2,3,5,6	18	MS-1, R-3, CS	6.04-10
SLC	7.54-11	2,3,5,6	19	MS-1, R-3, CF-2	3.72-11
		5,6	19	MS-1, R-3, CF-2	3.76-11
SL	6.10-15	2,3,5,6	21	MS-1, R-3, CF-2, CS	3.02-15
		5,6	21	MS-1, R-3, CF-2, CS	3.05-15
TEFC	9.41-5	2,3,5,6	22	MS-1, OP-3	9.14-5
TEF	1.26-8	2,3,5,6	24	MS-1, OP-3, CS	7.41-9
		2,3,6	24	MS-1, CS	2.49-9
		2,3,5	24	MS-1, CS	2.51-9
TEC	3.43-8	2,3,6	25	MS-1, CF-2	6.30-9
		2,3,5	25	MS-1, CF-2	4.03-9
		6	39	MS-1	7.86-9
		5	39	MS-1	7.86-9
		5	33	L-1	7.23-9
TE	1.63-8	2,3	41	MS-1	8.10-9
		No Power	41	MS-1	4.05-9
		No Power	35	L-1	3.72-9
ATWS	2.00-5	2,3,5,6	28	K-3	2.00-5

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

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1.3.5.6 Steam Break Outside Containment--Event Tree 6 (ET-6) Quantification

The frequency of the steam break outside containment initiating event, ϕ_6, is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_6) in Table 1.3.5.6-1. The other branch point split fraction data for the event tree (conditional on ϕ_6 and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.6-2.

When mean value data are propagated through the steam break outside containment event tree, the base case results shown in Table 1.3.5.6-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.5.6-3 do not include contributions via the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_6. The same table gives the split fractions, M^{β}_6, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.5.13, M(ATWS), the conditional plant matrix resulting from ATWS is calculated. In Section 1.4, M(ATWS) and all the M_i's are combined into the complete plant matrix, M.

Dominant sequences are listed in Table 1.3.5.6-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.5.6-1

STEAM BREAK OUTSIDE CONTAINMENT INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_6 - Steam Break Outside Containment (Annual Frequency)	1.06-6	1.16-4	6.30-3	1.95-3
AC Power Available at Buses (Given ϕ_6):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.71-7	6.46-6	4.49-5	1.71-5
2A, 3A, 5A	3.71-7	6.46-6	4.49-5	1.71-5
5A, 6A	4.24-5	8.48-5	1.63-4	9.54-5
2A, 3A	1.24-8	2.05-7	1.52-6	5.36-7
6A	1.50-8	2.05-7	1.45-6	5.32-7
5A	1.52-8	2.15-7	1.70-6	5.30-7
None	2.14-5	2.93-5	4.14-5	3.00-5

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-2

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	-	-	-	1.0	1.5.1
SA-2	SI Signal and High Head Pumps	2.4-5	8.7-5	3.3-4	1.3-4	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3-3
OP-1	Feed and Bleed Cooling	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
SA-2	SI Signal and High Head Pumps	1.2-5	9.6-5	7.5-4	2.0-4	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
SA-2	SI Signal and High Head Pumps	1.2-5	9.6-5	7.5-4	2.0-4	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	4.2-5	8.5-5	1.6-4	9.5-5	1.5.1
SA-2	SI Signal and High Head Pumps	1.2-5	9.6-5	7.5-4	2.0-4	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-1	Feed and Bleed Cooling	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam line Break Outside Containment	1.2-8	2.1-7	1.5-6	5.4-7	1.5.1
SA-2	SI Signal and High Head Pumps	-	-	-	1.0	1.3.3
R-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam line Break Outside Containment	1.5-8	2.1-7	1.5-6	5.3-7	1.5.1
SA-2	SI Signal and High Head Pumps	-	-	-	1.0	1.3.3
R-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam line Break Outside Containment	1.5-8	2.2-7	1.7-6	5.3-7	1.5.1
SA-2	SI Signal and High Head Pumps	-	-	-	1.0	1.3.3
R-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	2.1-5	2.9-5	4.1-5	3.0-5	1.5.1
SA-2	SI Signal and High Head Pumps	-	-	-	1.0	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.6-3

INDIAN POINT 2 STEAM LINE BREAK OUTSIDE CONTAINMENT EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_6 = [	0	0	0	0	7.46-6	6.05-10	7.54-11	6.10-15	9.41-5	1.26-8	3.43-8	1.63-8	0	0	0	0	0	0	0	0	0]
M'_6 = [	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None	
M_6^B = [	2.00-5	3.40-10	3.40-10	1.90-9	1.08-11	1.06-11	1.06-11	1.03-12	]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.5.6-4

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	7.46-6	2,3,5,6	16	MS-1, R-3	7.45-6
SLF	6.05-10	2,3,5,6	18	MS-1, R-3, CS	6.04-10
SLC	7.54-11	2,3,5,6	19	MS-1, R-3, CF-2	3.72-11
		5,6	19	MS-1, R-3, CF-2	3.76-11
SL	6.10-15	2,3,5,6	21	MS-1, R-3, CF-2, CS	3.02-15
		5,6	21	MS-1, R-3, CF-2, CS	3.05-15
TEFC	9.41-5	2,3,5,6	22	MS-1, OP-3	9.14-5
TEF	1.26-8	2,3,5,6	24	MS-1, OP-3, CS	7.41-9
		2,3,6	24	MS-1, CS	2.49-9
		2,3,5	24	MS-1, CS	2.51-9
TEC	3.43-8	2,3,6	25	MS-1, CF-2	6.30-9
		2,3,5	25	MS-1, CF-2	4.03-9
		6	39	MS-1	7.86-9
		5	39	MS-1	7.86-9
		5	33	L-1	7.23-9
TE	1.63-8	2,3	41	MS-1	8.10-9
		No Power	41	MS-1	4.05-9
		No Power	35	L-1	3.72-9
ATWS	2.00-5	2,3,5,6	28	K-3	2.00-5

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

1.3.5.7 Loss of Main Feedwater--Event Tree 7 (ET-7) Quantification

The frequency of the loss of main feedwater initiating event, ϕ_7, is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_7) in Table 1.3.5.7-1. The other branch point split fraction data for the event tree (conditional on ϕ_7 and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.7-2.

When mean value data is propagated through the loss of main feedwater event tree, the base case results shown in Table 1.3.5.7-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.5.7-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_7. The same table gives the split fractions, M^{β}_7, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.5.13, M(ATWS), the conditional plant matrix resulting from ATWS is calculated. In Section 1.4, M(ATWS) and all the M_i's are combined into the complete plant matrix, M.

Dominant sequences are listed in Table 1.3.5.7-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.5.7-1

LOSS OF FEEDWATER INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_7 - Loss of Feedwater (Annual Frequency)	4.84	6.47	8.23	6.70
AC Power Available at Buses (Given ϕ_7):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.71-7	6.46-6	4.49-5	1.71-5
2A, 3A, 5A	3.71-7	6.46-6	4.49-5	1.71-5
5A, 6A	4.24-5	8.48-5	1.63-4	9.54-5
2A, 3A	1.24-8	2.05-7	1.52-6	5.36-7
6A	1.50-8	2.05-7	1.45-6	5.32-7
5A	1.52-8	2.15-7	1.70-6	5.30-7
None	2.14-5	2.93-5	4.14-5	3.00-5

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-2

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	-	-	-	1.0	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-5	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	4.2-5	8.5-5	1.6-4	9.5-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	1.2-8	2.1-7	1.5-6	5.4-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT-1	Turbine Trip	7.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	1.5-8	2.1-7	1.5-6	5.3-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT-1	Turbine Trip	7.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	1.5-8	2.2-7	1.7-6	5.3-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT-1	Turbine Trip	7.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	2.1-5	2.9-5	4.1-5	3.0-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.7-3

INDIAN POINT 2 LOSS OF MAIN FEEDWATER FLOW EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_7 =	[0	0	0	0	9.47-9	7.67-13	4.49-13	3.64-17	1.19-7	3.93-11	7.48-9	3.94-9	0	0	0	0	0	0	0	0	0]
M'_7 =	[NOT REQUIRED]																				

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M_7^B	[2.00-5	3.40-10	3.40-10	1.90-9	1.08-11	1.06-11	1.06-11	1.03-12]

Notes:

1. M - Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.5.7-4

ET-7 - LOSS OF MAIN FEEDWATER EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Sequence and AC Buses Available		Dominant Sequences	
		Bus No. A	Seq.	Failed Branch Points	Conditional Frequency
SLFC	9.47-9	2,3,5,6	3	L-1, R-3	9.43-9
SLF	7.67-13	2,3,5,6	5	L-1, R-3, CS	7.65-13
SLC	4.49-13	5,6	6	L-1, R-3, CF-2	4.01-13
SL	3.64-17	5,6	8	L-1, R-3, CF-2, CS	3.25-17
TEFC	1.19-7	2,3,5,6	9	L-1, OP-2	1.16-7
TEF	3.93-11	2,3,5	11	L-1, CS	2.68-11
		2,3,5,6	11	L-1, OP-2, CS	9.39-12
		2,3,6	11	L-1, CS	3.15-12
TEC	7.48-9	5	12	L-1, CF-2	7.34-9
TE	3.94-9	No Power	14	L-1	3.78-9
ATWS	2.00-5	2,3,5,6	42	K-3	2.00-5

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

1.3.5.8 Closure of One Main Steam Isolation Valve--Event Tree 8 (ET-8) Quantification

The frequency of the trip of one MSIV initiating event, ϕ_8 is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_8) in Table 1.3.5.8-1. The other branch point split fraction data for the event tree (conditional on ϕ_8 and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.8-2.

When mean value data are propagated through the trip of one MSIV event tree, the base case results shown in Table 1.3.5.8-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

Dominant sequences are listed in Table 1.3.5.8-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.5.8-1

CLOSURE OF ONE MSIV INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_8 - Closure of One MSIV (Annual Frequency)	5.30-1	1.14	1.99	1.25
AC Power Available at Buses (Given ϕ_8):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.71-7	6.46-6	4.49-5	1.71-5
2A, 3A, 5A	3.71-7	6.46-6	4.49-5	1.71-5
5A, 6A	4.24-5	8.48-5	1.63-4	9.54-5
2A, 3A	1.24-8	2.05-7	1.52-6	5.36-7
6A	1.50-8	2.05-7	1.45-6	5.32-7
5A	1.52-8	2.15-7	1.70-6	5.30-7
None	2.14-5	2.93-5	4.14-5	3.00-5

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.8-2

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	-	-	-	1.0	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	4.2-5	8.5-5	1.6-4	9.5-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	1.2-8	2.1-7	1.5-6	5.4-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	1.5-8	2.1-7	1.5-6	5.3-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	1.5-8	2.2-7	1.7-6	5.3-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-2	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.8-4

ET-8 - CLOSURE OF ONE MSIV EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	9.47-9	2,3,5,6	3	L-1, R-3	9.43-9
SLF	7.67-13	2,3,5,6	5	L-1, R-3, CS	7.65-13
SLC	4.49-13	2,3,5,6	6	L-1, R-3, CF-2	4.72-14
		5,6	6	L-1, R-3, CF-2	4.01-13
SL	3.64-17	2,3,5,6	8	L-1, R-3, CF-2, CS	3.82-18
		5,6	8	L-1, R-3, CF-2, CS	3.25-17
TEFC	1.19-7	2,3,5,6	9	L-1, OP-2	1.16-7
TEF	3.93-11	2,3,5,6	11	L-1, OP-2, CS	9.39-12
		2,3,6	11	L-1, CS	3.15-12
		2,3,5	11	L-1, CS	2.68-11
TEC	7.48-9	6	12	L-1	8.38-11
		5	12	L-1	7.34-9
TE	3.94-9	No Power	14	L-1	3.78-9

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

1.3.5.9 Loss of Reactor Coolant System Flow--Event Tree 9 (ET-9) Quantification

The frequency of the loss of reactor coolant system flow initiating event, ϕ_9 is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_9) in Table 1.3.5.9-1. The other branch point split fraction data for the event tree (conditional on ϕ_9 and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.9-2.

When mean value data is propagated through the loss of RCS flow event tree, the base case results shown in Table 1.3.5.9-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.5.9-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_9. The same table gives the split fractions, M^{β}_9, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.5.13, M(ATWS), the conditional plant matrix resulting from ATWS is calculated. In Section 1.4, M(ATWS) and all the M_i's are combined into the complete plant matrix, M.

Dominant sequences are listed in Table 1.3.5.9-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.5.9-1

LOSS OF PRIMARY FLOW INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_9 - Loss of Primary Flow (Annual Frequency)	1.13-2	8.78-2	3.33-1	1.36-1
AC Power Available at Buses (Given ϕ_9):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.71-7	6.46-6	4.49-5	1.71-5
2A, 3A, 5A	3.71-7	6.46-6	4.49-5	1.71-5
5A, 6A	4.24-5	8.48-5	1.63-4	9.54-5
2A, 3A	1.24-8	2.05-7	1.52-6	5.36-7
6A	1.50-8	2.05-7	1.45-6	5.32-7
5A	1.52-8	2.15-7	1.70-6	5.30-7
None	2.14-5	2.93-5	4.14-5	3.00-5

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-2

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	-	-	-	1.0	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Additon	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Additon	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Additon	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	1.2-8	2.1-7	1.5-6	5.4-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Additon	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	4.2-5	8.5-5	1.6-4	9.5-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Additon	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	1.5-8	2.1-7	1.5-6	5.3-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Additon	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	1.5-8	2.2-7	1.7-6	5.3-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-3	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Additon	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	2.1-5	2.9-5	4.1-5	3.0-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Additon	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.9-3

INDIAN POINT 2 LOSS OF PRIMARY FLOW EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_9 = [	0	0	0	0	8.52-9	6.91-13	4.04-13	3.27-17	1.07-7	3.54-11	6.74-9	3.55-9	0	0	0	0	0	0	0	0	0]
M'_9 = [	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M_9^{β} = [	1.80-5	3.06-10	3.06-10	1.71-9	9.72-12	9.54-12	9.54-12	9.23-13]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

3. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.5.9-4

ET-9 - LOSS OF REACTOR COOLANT SYSTEM FLOW EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	8.52-9	2,3,5,6	3	L-1, R-3	8.49-9
SLF	6.91-13	2,3,5,6	5	L-1, R-3, CS	6.88-13
SLC	4.04-13	5,6	6	L-1, R-3, CF-2	3.61-13
SL	3.27-17	5,6	8	L-1, R-3, CF-2,	2.93-17
TEFC	1.07-7	2,3,5,6	9	L-1, OP-2	1.04-7
TEF	3.54-11	2,3,5 2,3,5,6 2,3,6	11 11 11	L-1, CS L-1, OP-2, CS L-1, CS	2.41-11 8.45-12 2.83-12
TEC	6.74-9	5	12	L-1,	6.60-9
TE	3.55-9	No Power	14	L-1	3.40-9
ATWS	1.80-5	2,3,5,6	42	K-3	1.80-5

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

1.3.5.10 Core Power Excursion--Event Tree 10 (ET-10) Quantification

The frequency of the core power excursion initiating event, ϕ_{10} is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_{10}) in Table 1.3.5.10-1. The other branch point split fraction data for the event tree (conditional on ϕ_{10} and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.10-2.

When mean value data is propagated through the core power excursion event tree, the base case results shown in Table 1.3.5.10-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.5.10-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_{10}. The same table gives the split fractions, M^{β}_{10}, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.5.13, M(ATWS), the conditional plant matrix resulting from ATWS is calculated. In Section 1.4, M(ATWS) and all the M_i's are combined into the complete plant matrix, M.

Dominant sequences are listed in Table 1.3.5.10-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.5.10-1

CORE POWER EXCURSION INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{10} - Core Power Excursion (Annual Frequency)	3.23-5	9.23-3	6.82-2	2.21-2
AC Power Available at Buses (Given ϕ_{10}):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.71-7	6.46-6	4.49-5	1.71-5
2A, 3A, 5A	3.71-7	6.46-6	4.49-5	1.71-5
5A, 6A	4.24-5	8.48-5	1.63-4	9.54-5
2A, 3A	1.24-8	2.05-7	1.52-6	5.36-7
6A	1.50-8	2.05-7	1.45-6	5.32-7
5A	1.52-8	2.15-7	1.70-6	5.30-7
None	2.14-5	2.93-5	4.14-5	3.00-5

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-2

ET-10 - CORE POWER EXCURSION

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	-	-	-	1.0	1.5.1
OP-3	Operation Terminates Excursion	3.5-6	6.8-5	2.1-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
OP-3	Operation Terminates Excursion	3.5-6	6.8-5	2.1-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
OP-3	Operation Terminates Excursion	3.5-6	6.8-5	2.1-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	4.2-5	8.5-5	1.6-4	9.5-5	1.5.1
OP-3	Operation Terminates Excursion	3.5-6	6.8-5	2.1-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	1.2-8	2.1-7	1.5-6	5.4-7	1.5.1
OP-3	Operation Terminates Excursion	3.5-6	6.8-5	2.1-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	1.5-8	2.1-7	1.5-6	5.3-7	1.5.1
OP-3	Operation Terminates Excursion	3.5-6	6.8-5	2.1-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	1.5-8	2.2-7	1.7-6	5.3-7	1.5.1
OP-3	Operation Terminates Excursion	3.5-6	6.8-5	2.1-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-2 (continued)

ET-10 - CORE POWER EXCURSION

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	2.1-5	2.9-5	4.1-5	3.0-5	1.5.1
OP-3	Operation Terminates Excursion	3.5-6	6.8-5	2.1-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.10-3

INDIAN POINT 2 CORE POWER EXCURSION EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{10} = [	0	0	0	0	3.31-15	2.68-19	1.57-19	1.27-23	4.16-14	1.38-17	2.62-15	1.38-15	0	0	0	0	0	0	0	0	0]
M'_{10} = [	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{e}_{10} = [	7.00-12	1.19-16	1.19-16	6.65-16	3.78-18	3.71-18	3.71-18	3.59-19]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.5.10-4

ET-10 - CORE POWER EXCURSION EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	3.31-15	2,3,5,6	5	OP-2, K-5, L-1, R-3	3.30-15
SLF	2.68-19	2,3,5,6	7	OP-2, K-5, L-1, R-3, CS	2.68-19
SLC	1.57-19	2,3,5,6	8	OP-4, K-5, L-1, R-3 CF-2	1.65-20
		5,6	8	OP-4, K-5, L-1, R-3 CF-2	1.40-19
SL	1.27-23	2,3,5,6	10	OP-4, K-5, L-1, R-3, CF-2, CS	1.34-24
		5,6	10	OP-4, K-5, L-1, R-3, CF-2, CS	1.14-23
TEFC	4.16-14	2,3,5,6	11	OP-4, K-5, L-1, OP-2	4.05-14
TEF	1.38-17	2,3,5,6	13	OP-4, K-5, L-1, OP-2, CS	3.29-18
		2,3,6	13	OP-4, K-5, L-1, CS	1.10-18
		2,3,5	13	OP-4, K-5, L-1, CS	9.37-18
TEC	2.62-15	5	14	OP-4, K-5, L-1,	2.57-15
TE	1.38-15	No Power	16	OP-4, K-5, L-1	1.32-15
AFWS	7.00-12	2,3,5,6	17	OP-4, K-5, K-3	7.00-12

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

1.3.5.11 Turbine Trip--Event Tree 11 (ET-11) Quantification

1.3.5.11.1 Turbine Trip Base Case Quantification

The frequency of the turbine trip (general) initiating event, ϕ_{11a} is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_{11a}) in Table 1.3.5.11a-1. The other branch point split fraction data for the event tree (conditional on ϕ_{11a} and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.11a-2.

When mean value data is propagated through the turbine trip (general) event tree (ET-11a), the base case results shown in Table 1.3.5.11a-3 are obtained. No important plant split fractions that are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.5.11a-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_{11a}. The same table gives the split fractions, M^{β}_{11a}, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.5.13, M(ATWS), the conditional plant matrix resulting from ATWS is calculated. In Section 1.4, M(ATWS) and all the M_i's are combined into the complete plant matrix, M.

Dominant sequences are listed in Table 1.3.5.11a-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

1.3.5.11.2 Turbine Trip--Loss of Offsite Power Quantification

The frequency of the turbine trip--loss of offsite power initiating event, ϕ_{11b}, is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_{11b}) in Table 1.3.5.11b-1. The other branch point split fraction data for the event tree (conditional on ϕ_{11b} and electric power state) is developed in Sections 1.3.2, 1.3.3, and 1.5.2 and is summarized in Table 1.3.5.11b-2. Many degraded states of electric power appear to be important for this event tree because it is initiated by a loss of offsite power. Therefore, the entire tree has been revised to account for recovery of electric power as described in Section 1.3.2.2.

The plant split fractions in Table 1.3.5.11b-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contributions are labeled M_{11b}. The same table gives the split fractions, M^{β}_{11b}, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.5.13, M(ATWS), the conditional plant matrix resulting from ATWS is calculated. In Section 1.4, M(ATWS) and all the M_i's are combined into the complete plant matrix, M.

Dominant sequences are listed in Table 1.3.5.11b-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

1.3.5.11.3 Turbine Trip--Loss of Service Water Quantification

The frequency of the turbine trip--loss of service water initiating event, ϕ_{11c} is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_{11c}) in Table 1.3.5.11c-1. The other branch point split fraction data for the event tree (conditional on ϕ_{11c} and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.11c-2.

When mean value data is propagated through the turbine trip--loss of service water event tree--the base case results shown in Table 1.3.5.11c-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.5.11c-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contributions are labeled M_{11c}. The same table gives the split fractions, M^{β}_{11c}, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.5.13, M(ATWS), the conditional plant matrix resulting from ATWS is calculated. In Section 1.4, M(ATWS) and all the M_i's are combined into the complete plant matrix, M.

Dominant sequences are listed in Table 1.3.5.11c-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.5.11a-1

TURBINE TRIP INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{11a} - Turbine Trip (Annual Frequency)	5.35+0	7.15+0	9.10+0	7.32+0
AC Power Available at Buses (Given ϕ_{11a}):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.71-7	6.46-6	4.49-5	1.71-5
2A, 3A, 5A	3.71-7	6.46-6	4.49-5	1.71-5
5A, 6A	4.24-5	8.48-5	1.63-4	9.54-5
2A, 3A	1.24-8	2.05-7	1.52-6	5.36-7
6A	1.50-8	2.05-7	1.45-6	5.32-7
5A	1.52-8	2.15-7	1.70-6	5.30-7
None	2.14-5	2.93-5	4.14-5	3.00-5

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-2

ET-11a - TURBINE TRIP

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	-	-	-	1.0	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	4.2-5	8.5-5	1.6-4	9.5-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	1.2-8	2.1-7	1.5-6	5.4-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	1.5-8	2.1-7	1.5-6	5.3-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	1.5-8	2.2-7	1.7-6	5.3-7	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-2 (continued)

ET-11a - TURBINE TRIP

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	2.1-5	2.9-5	4.1-5	3.0-5	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11a-3

INDIAN POINT 2 TURBINE TRIP EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

PLANT EVENT SEQUENCE CATEGORY[3]

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{11A} = [	0	0	0	0	9.45-9	7.66-13	4.49-13	3.64-17	1.19-7	3.93-11	7.48-9	3.94-9	0	0	0	0	0	0	0	0	0]
M'_{11A} = [	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{B}_{11A} = [	2.00-5	3.40-10	3.40-10	1.90-9	1.08-11	1.06-11	1.06-11	5.40-12]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.5.11a-4

ET-11a - TURBINE TRIP EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	9.45-9	2,3,5,6	3	L-1, R-3	9.43-9
SLF	7.66-13	2,3,5,6	5	L-1, R-3, CS	7.65-13
SLC	4.49-13	5,6	6	L-1, R-3, CF-2	4.01-13
		2,3,5,6	6	L-1, R-3, CF-2	4.72-14
SL	3.64-17	5,6	8	L-1, R-3, CF-2, CS	3.25-17
		2,3,5,6	8	L-1, R-3, CF-2, CS	3.82-18
TEFC	1.19-7	2,3,5,6	9	L-1, OP-2	1.16-7
TEF	3.93-11	2,3,5	11	L-1, CS	2.68-11
		2,3,5,6	11	L-1, OP-2, CS	9.39-12
		2,3,6	11	L-1, CS	3.15-12
TEC	7.48-9	5	12	L-1	7.34-9
TE	3.94-9	No Power	14	L-1	3.78-9
ATWS	2.00-5	2,3,5,6	15	K-3	2.00-5

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

TABLE 1.3.5.11b-1

TURBINE TRIP - LOSS OF OFFSITE POWER
INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{11b} - Turbine Trip - Loss of Offsite Power (Annual Frequency)	5.02-2	1.47-1	4.32-1	1.82-1
AC Power Available at Buses (Given ϕ_{11b}):				
2A, 3A, 5A, 6A	8.28-1	8.57-1	8.81-1	8.59-1
2A, 3A, 6A	2.99-2	4.33-2	5.90-2	4.54-2
2A, 3A, 5A	2.99-2	4.33-2	5.90-2	4.54-2
5A, 6A	2.99-2	4.33-2	5.90-2	4.54-2
2A, 3A	7.56-4	1.30-3	2.01-3	1.40-3
6A	7.56-4	1.30-3	2.01-3	1.40-3
5A	7.56-4	1.30-3	2.01-3	1.40-3
None	4.52-4	6.03-4	7.82-4	6.18-4

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-2

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	8.3-1	8.6-1	8.8-1	8.6-1	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
LS	RCP Seal LOCA	2.6-6	7.6-6	2.2-4	1.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	3.0-2	4.3-2	5.9-2	4.5-2	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
LS	RCP Seal LOCA	1.6-4	4.5-4	1.3-3	6.1-4	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	3.0-2	4.3-2	5.9-2	4.5-2	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
LS	RCP Seal LOCA	2.6-6	7.6-6	2.2-4	1.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	3.0-2	4.3-2	5.9-2	4.5-2	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
LS	RCP Seal LOCA	2.8-3	5.7-3	9.9-3	6.5-3	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-2 (continued)

ET-11b - TT - LOSS OF OFFSITE POWER

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	7.6-4	1.3-3	2.0-3	1.4-3	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
LS	RCP Seal LOCA	1.6-4	4.5-4	1.3-3	6.1-4	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-2 (continued)

ET-11b - TT - LOSS OF OFFSITE POWER

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	7.6-4	1.3-3	2.0-3	1.4-3	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
LS	RCP Seal LOCA	-	-	-	1.0	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-2 (continued)

ET-11b - TT - LOSS OF OFFSITE POWER

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	7.6-4	1.3-3	2.0-3	1.4-3	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
LS	RCP Seal LOCA	2.8-3	5.7-3	3.6-2	6.5-3	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	4.5-4	6.0-4	7.8-4	6.2-4	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
LS	RCP Seal LOCA	-	-	-	1.0	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11b-3

INDIAN POINT 2 TURBINE TRIP, LOSS OF OFFSITE POWER EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{11B} =	[NOT MEANINGFUL]																				
M'_{11B} =	[1.78-4	1.45-8	2.18-5	5.56-6	8.57-7	3.70-10	3.75-10	1.32-12	7.92-7	7.51-10	1.20-9	1.19-11	0	0	0	0	0	0	0	0	0]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{B}_{11B} = [	3.32-6	1.56-7	1.56-7	1.56-7	3.80-9	3.80-9	3.80-9	1.56-9]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.5.11b-4

ET-11b(R) - TURBINE TRIP, LOSS OF OFFSITE POWER
EVENT TREE DOMINANT SEQUENCES
(With Recovery)

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Initially Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	1.62-4	No Power	41*	R-2	1.62-4
SLF	4.09-6	No Power	41	R-2, CS	4.09-6
SLC	4.08-6	No Power	41	CF-1, R-2	3.98-6
		No Power	41	CF-1, R-2, NA	9.84-8
SL	1.01-7	No Power	41	CF-1, R-2, CS	1.01-7
SEFC	6.95-4	No Power	41	HH-2	6.25-4
		No Power	41	L-1, HH-2, NA	5.45-5
		No Power	41	HH-2, NA	1.54-5
SEF	1.72-5	No Power	41	HH-2, CS	1.58-5
		No Power	41	L-1, CS	1.38-6
SEC	1.67-5	No Power	41	HH-2, CF-1	1.54-5
		No Power	41	L-1, CF-1	1.34-6
SE	4.21-7	No Power	41	HH-2, CF-1, CS	3.87-7
		No Power	41	L-1, CF-1, CS	3.38-8

*Sequence 41 is a small LOCA due to reactor coolant pump seal failure. The sequence branches to the small LOCA Event Tree (ET-3) where it is quantified conditional on successful reactor trip and AC bus availability. Recovery of electric power is modeled there.

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

TABLE 1.3.5.11b-4 (continued)

ET-11b(R) - TURBINE TRIP, LOSS OF OFFSITE POWER
EVENT TREE DOMINANT SEQUENCES
(With Recovery)

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Initially Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
TEFC	7.69-7	2,3,5,6	9	L-1, OP-2	1.07-7
		2,3,6	29	L-1, EP-2, OP-2	4.88-8
		2,3,6	35	L-1, EP-2, OP-2, EP-3	1.65-8
		2,3,5	29	L-1, EP-2, OP-2	4.12-7
		2,3,5	35	L-1, EP-2, OP-2, EP-3	1.41-7
		2,3,5	9	L-1, OP-2	1.92-8
		5,6	9	L-1, OP-2	1.91-8
TEF	1.64-9	2,3,6	37	L-1, EP-2, OP-2, EP-3, CS	1.68-10
		2,3,5	37	L-1, EP-2, OP-2, EP-3, CS	1.42-9
TEC	2.76-9	2,3,6	38	L-1, EP-2, OP-2, EP-3, CS	4.25-10
		2,3,5	38	L-1, EP-2, OP-2, EP-3, CS	2.29-9
TE	2.75-11	2,3,6	40	L-1, EP-2, OP-2, EP-3, CS, LS	4.30-12
		2,3,5	40	L-1, EP-2, OP-2, EP-3, CS, LS	2.31-11
ATWS	1.98-5	2,3,5,6	42	K-3	1.74-5
		2,3,6	42	K-3	8.00-7
		2,3,5	42	K-3	8.00-7
		5,6	42	K-3	8.00-7

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

TABLE 1.3.5.11c-1

TURBINE TRIP - LOSS OF SERVICE WATER
INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{11c} - Turbine Trip - Loss of Service Water (Annual Frequency)	1.06-6	1.16-4	6.30-3	1.95-3
AC Power Available at Buses (Given ϕ_{11c}):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
None	6.46-5	1.28-4	2.59-4	1.61-4

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11c-2

ET-11c - TURBINE TRIP, LOSS OF SERVICE WATER

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11c	Turbine Trip, Loss of Service Water	-	-	-	1.0	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11c-2 (continued)

ET-11c - TURBINE TRIP, LOSS OF SERVICE WATER

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11c	Turbine Trip, Loss of Service Water	6.5-5	1.3-4	2.6-4	1.6-4	1.5.1
K-3	Reactor Trip	4.3-7	4.2-6	7.0-5	2.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.11c-3

INDIAN POINT 2 TURBINE TRIP, LOSS OF SERVICE WATER EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{11C} = [	0	0	0	0	0	0	1.89-5	1.53-9	0	0	1.16-7	1.82-6	0	0	0	0	0	0	0	0	0]
M'_{11C} = [	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and None
M^{β}_{11C} = [	2.00-5	4.94-10]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.5.11c-4

ET-11c - TURBINE TRIP, LOSS OF SERVICE WATER
EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. __A	Seq.		
SLC	1.89-5	2,3,5,6	6	L-1	1.89-5
SL	1.53-9	2,3,5,6	8	L-1, CS	1.53-9
TEC	1.16-7	2,3,5,6	12	L-1, OP-2	1.16-7
TE	1.82-6	No Power	14	L-1	1.82-6
ATWS	2.00-5	2,3,5,6	15	K-3	2.00-5

Note: Values are presented in abbreviated scientific notation; e.g., 1.89-5 = 1.89×10^{-5}.

1.3.5.12 Reactor Trip--Event Tree 12 (ET-12) Quantification

1.3.5.12.1 Reactor Trip, Base Case Quantification

The frequency of the reactor trip initiating event, ϕ_{12a}, is developed in Section 1.5.1 and is shown with the electric power state split fraction data (conditional on ϕ_{12a}) in Table 1.3.5.12a-1. The other branch point split fraction data for the event tree (conditional on ϕ_{12a} and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.12a-2.

When mean value data are propagated through the reactor trip event tree, the base case results shown in Table 1.3.5.12a-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

Dominant sequences are listed in Table 1.3.5.12a-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The frequencies of those sequences are requantified there to properly account for uncertainty.

1.3.5.12.2 Special Initiating Events That Fail Mitigating Systems by Common Cause

The plant event trees are modeled for the conditions of all DC and ESF AC buses, component cooling water, and service water are available just before the initiating event. Loss of any of these systems leads to a reactor trip or shutdown. Loss of service water has been examined using the turbine trip event tree in Section 1.3.4.11. In this section, the effects of the other support system failures on risk are calculated.

1. Loss of Component Cooling Water. When component cooling is lost, the plant will be shut down or tripped. The operator may trip the reactor coolant pumps first, which leads to a low flow reactor trip. The loss of component cooling event is analyzed by quantifying the reactor trip event tree with the split fraction for the component cooling system failure set to 1.0. Failure of component cooling will not lead to more serious degradation of safety equipment than analyzed here unless the system is drained of all water by a large component cooling water pipe break at the lower elevations of the plant. Such a scenario is very unlikely given the system design and location, as shown in the analysis of Section 1.3.8.1, and is therefore a negligible contributor to risk.

   The frequency of the reactor trip, loss of component cooling water initiating event, ϕ_{12b}, is developed in Section 1.5.1 and shown with the electric power state split fraction data (conditional on ϕ_{12b}) in Table 1.3.5.12b-1. The other branch point split fraction data for the event tree (conditional on ϕ_{12b} and electric power state) is developed in Sections 1.3.3 and 1.5.2 and is summarized in Table 1.3.5.12b-2.

   When mean value data are propagated through the reactor trip event tree, the results shown in Table 1.3.5.12b-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

Dominant sequences are listed in Table 1.3.5.12b-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

2. Loss of DC Power. Loss of power at DC power panel 21 or 22 will cause a reactor trip because each power panel supplies one of the reactor protection trip logic channels. Failure of DC control power at a 480V bus prevents the automatic closure of standby equipment circuit breakers. Although operating equipment will continue to run under this condition (the breakers are prevented from opening), the effects of this DC control power failure are conservatively modeled in this boundary analysis as equivalent to the failure of AC power at the affected bus.

   The design of the Indian Point Unit 2 DC control power system includes a normal and a backup source of DC power for circuit breaker operations at each 480V switchgear bus. Similarly, two sources of DC power are provided for control of each of the diesel generators. These power supplies are summarized below:

Control Power Supply	Normal DC Power Source (power panel)	Backup DC Power Source (power panel)
480V Bus 2A	22	24
480V Bus 3A	21	23
480V Bus 5A	21	23
480V Bus 6A	22	24
Diesel Generator 21	21	23
Diesel Generator 22	22	23
Diesel Generator 23	22	24

   If the normal source of DC power fails, a voltage-sensing transfer switch at the affected location automatically reenergizes the control power supply from the backup source. Therefore, complete failure of DC control power at a given 480V bus thus requires failure of the normal supply and either failure of power from the backup supply or failure of the transfer device to operate when normal voltage is lost.

   Each DC power panel is powered from its own battery and battery charger. The battery charger normally supplies the DC loads and maintains the battery on a trickle charge. No routinely scheduled tests or maintenance activities that affect the availability of either the charger or the battery are performed during unit power operation. The Indian Point Unit 2 technical specifications allow either battery 21 or 22 (but not both) to be out of service for a maximum period of 24 hours during power operation. If this period is exceeded, the unit must be shut down. Also, if battery

charger 21 or 22 is removed from service, the unit must be shut down immediately. For this analysis, it is assumed that equipment is removed from service only for nonroutine maintenance of failed or degraded components. To bound the maintenance unavailability, it is further assumed that each maintenance event of battery 21 or 22 results in the battery being removed from service for the entire allowed period of 24 hours, plus an additional 4 hours to account for the time required to bring the unit to subcritical conditions using normal shutdown procedures. Each maintenance event of battery charger 21 or 22 is assumed to span 4 hours before the unit is subcritical. Maintenance performed on batteries 23 or 24, or battery chargers 23 or 24 is conservatively estimated to require 7 days (168 hours) to complete because they are not included in the technical specifications. Section 1.5.1 provides the following mean failure rate information for the components included in this analysis:

- Circuit breaker transfers open — 4.81×10^{-7}/hour
- Battery charger failure — 2.01×10^{-6}/hour
- Battery failure — 8.21×10^{-8}/hour
- Fuse opens prematurely — 8.32×10^{-7}/hour
- Auto-transfer device failure — 2.71×10^{-6}/demand
- DC bus failure — 2.80×10^{-8}/hour

Maintenance of the battery charger supply will be required if the charger input or output circuit breaker fails or if the charger itself fails. The combined mean failure rate for these components is 2.97×10^{-6} failure/hour. Multiplying this required maintenance frequency by the bounding 4-hour time period results in a mean unavailability from maintenance of the battery charger supply of 1.19×10^{-5}. DC power will be lost at the power panel if either the battery or its output fuse fails when the charger supply is unavailable. The combined mean failure rate for these components is 9.14×10^{-7} failure/hour. Multiplying this failure frequency by the unavailability of the charger power supply results in the following mean frequency of DC power panel failures from the combined effects of charger maintenance and battery failures. This is expressed as

$$\phi_{BFCM} = 1.09 \times 10^{-11} \text{ failure/hour}$$

The failure frequency information also indicates that maintenance of the battery supply will occur at a mean frequency of 9.14×10^{-7} events/hour. After applying the 28-hour bounding event duration, the resulting unavailability of this supply from maintenance is 2.56×10^{-5}. The mean frequency of DC power panel failures from the combined effects of battery maintenance and charger failures is

$$\phi_{BMCF} = 7.60 \times 10^{-11} \text{ failure/hour}$$

DC power will also be lost at a power panel if the panel itself fails (ϕ_{PF} = 2.80 x 10^{-8} failure/hour). The combined mean frequency of power failures at any given DC power panel from these three contributing causes is

$$\phi_{PPF} = \phi_{BFCM} + \phi_{BMCF} + \phi_{PF} = 2.81 \times 10^{-8} \text{ failure/hour}$$

This DC power failure analysis has explicitly included the effects of hardware failures, testing (no contribution), and component maintenance. No single human action that could directly lead to failure of power at a DC power panel and failure of control power at a 480V bus can be identified. Switching errors could affect a single power panel, but should not affect the automatic transfer to the backup power supply. Errors involving the local transfer switch could interrupt DC control power to a switchgear bus; however, these errors should not affect the power panel and would not cause a reactor trip. For the purpose of this boundary analysis, each battery or battery charger maintenance event is assumed to involve local switching actions which could interrupt DC power at the power panel if improperly performed (e.g., the operator could inadvertantly open the battery charger output breaker with the battery isolated for maintenance). Section 1.5.1 provides a mean frequency of 4.7 x 10^{-3} errors/switching event to account for the human error of selecting the wrong breaker during switching operations (ϕ_{SWE}). It is assumed that similar switching operations must be performed to remove a battery or charger from service and to restore it following maintenance. Therefore, each maintenance event contributes two possible sources of error related power failures. From the preceding analysis, the combined mean frequency of maintenance, ϕ_M, for the charger and the battery at a given DC power panel is 3.88 x 10^{-6} maintenance event/hour. The mean frequency of power failure at the DC power panel from human errors related to these maintenance events is

$$\phi_{HEF} = \phi_M \times \phi_{SWE} \times 2 = 3.65 \times 10^{-8} \text{ failure/hour}$$

The total frequency of DC power failure at a given DC power panel from human error, hardware failure, testing and maintenance effects is approximately

$$\phi_{NSF} = \phi_{PPF} + \phi_{HEF} = 6.46 \times 10^{-8} \text{ failure/hour}$$

Therefore, the mean frequency of reactor trips attributable to the failure of power at either DC power panel 21 or 22 is approximately 1.1 x 10^{-3} trips/year. This trip frequency is insignificant compared with the annual number of reactor trips and transients from other causes.

Failure of DC control power at a 480V switchgear bus requires failure of both the normal and backup sources of power. This condition is dominated by failure of the normal supply (ϕ_{NSF}) and failure of the

automatic transfer device to switch to the backup supply. Therefore, the mean frequency of DC power panel failure reactor trips which also result in loss of control power at a given 480V bus is

$$\phi_{IB} = (2.7 \times 10^{-6})\ \phi_{NSF} = 1.54 \times 10^{-9} \text{ event/year}$$

If both the normal and backup sources of the DC control power fail because of failures at the DC power panels, control power will be lost at two 480V buses (e.g., failure at power panels 21 and 23 affect buses 3A and 5A; power panels 22 and 24 affects buses 2A and 6A). The frequency of power failure at DC power panel 23 or 24, including maintenance switching errors and the bounding maintenance event duration of seven days, is

$$\phi_{BSF} = 6.54 \times 10^{-8} \text{ failure/hour}$$

Following the failure of power from the normal source, the backup supply failure rate is applied over the nominal 6-hour period of the electric power system analysis. The mean frequency at which DC power fails at power panel 21 or 22, causing a reactor trip, and at which control power is lost at two 480V switchgear buses (3A and 5A, or 2A and 6A) is approximately:

$$\phi_{2B} = \phi_{NSF} \times \phi_{BSF} \times 6 = 2.22 \times 10^{-10} \text{ event/year}$$

This bounding analysis has demonstrated that the mean frequency of events in which DC power failure causes a reactor trip and loss of control power to at least one AC bus is extremely small, considering independent failures of the normal and the backup supplies to each bus. Common cause failure of the DC power system has been explicitly included in the seismic and fire analysis sections of this study. These contributions to simultaneous reactor trip and control power failure scenarios dominate the independent supply failures. The AC electrical power system analysis has also shown that the unavailability of power at a 480V switchgear bus following a unit trip from any cause other than loss of offsite power is approximately 5.1×10^{-5}. This includes failures at bus 5A, bus 6A, or buses 2A and 3A. This value excludes the effects of operator actions to recover power, as does the quantification of DC power failure events presented before. The combined frequency of reactor trips and transient initiating events (other than the loss of offsite power) used in this study is approximately 22 events/year for Indian Point Unit 2. The unavailability of power at a 480V bus following the loss of offsite power is approximately 1.4×10^{-1}. This includes failures at bus 5A, bus 6A, or buses 2A and 3A. The mean frequency of the loss of offsite power initiating event is approximately 0.20 events/year for Unit 2. Therefore, the combined frequency at which a unit trip occurs and AC power is lost at any one 480V bus (or at buses 2A and 3A) from causes other than the failure of DC control power has been calculated to be approximately 2.9×10^{-2} events/year. Because the DC power failure event is clearly bounded by these other initiators, including seismic and fire related common cause failures, it need not be quantified as a separate initiating event category.

TABLE 1.3.5.12a-1

REACTOR TRIP INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{12a} - Reactor Trip (Annual Frequency)	4.95+0	6.58+0	8.54+0	6.84+0
AC Power Available at Buses (Given ϕ_{12a}):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.71-7	6.46-6	4.49-5	1.71-5
2A, 3A, 5A	3.71-7	6.46-6	4.49-5	1.71-5
5A, 6A	4.24-5	8.48-5	1.63-4	9.54-5
2A, 3A	1.24-8	2.05-7	1.52-6	5.36-7
6A	1.50-8	2.05-7	1.45-6	5.32-7
5A	1.52-8	2.15-7	1.70-6	5.30-7
None	2.14-5	2.93-5	4.14-5	3.00-5

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-2

ET-12a - REACTOR TRIP

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	-	-	-	1.0	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	4.2-5	8.5-5	1.6-4	9.5-5	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	1.2-8	2.1-7	1.5-6	5.4-7	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	1.5-8	2.1-7	1.5-6	5.3-7	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	1.5-8	2.2-7	1.7-6	5.3-7	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-2 (continued)

ET-12a - REACTOR TRIP

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	2.1-5	2.9-5	4.1-5	3.0-5	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12a-3

INDIAN POINT 2 REACTOR TRIP EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{12A} = [	0	0	0	0	9.47-9	7.67-13	4.49-13	3.64-17	1.19-7	3.93-11	7.49-9	3.94-9	0	0	0	0	0	0	0	0	0]
M'_{12A} = [	NOT REQUIRED																				]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior

   E - Early melt
   L - Late melt

   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.5.12a-4

ET-12a - REACTOR TRIP EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	9.47-9	2,3,5,6	3	L-1, R-3	9.43-9
SLF	7.67-13	2,3,5,6	5	L-1, R-3, CS	7.65-13
SLC	4.49-13	2,3,5,6	6	L-1, R-3, CF-2	4.72-14
		5,6	6	L-1, R-3, CF-2	4.01-13
SL	3.64-17	2,3,5,6	8	L-1, R-3, CF-2, CS	3.82-18
		5,6	8	L-1, R-3, CF-2, CS	3.25-17
TEFC	1.19-7	2,3,5,6	9	L-1, OP-2	1.16-7
TEF	3.93-11	2,3,5,6	11	L-1, OP-2, CS	9.39-12
		2,3,6	11	L-1, CS	3.15-12
		2,3,5	11	L-1, CS	2.68-11
TEC	7.49-9	5	12	L-1	7.34-9
TE	3.94-9	No Power	14	L-1	3.78-9

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

TABLE 1.3.5.12b-1

REACTOR TRIP - LOSS OF COMPONENT COOLING WATER
INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{12b} - Reactor Trip - Loss of Component Cooling Water (Annual Frequency)	1.06-6	1.16-4	6.30-3	1.95-3
AC Power Available at Buses (Given ϕ_{12b}):				
2A, 3A, 5A, 6A	9.98-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.71-7	6.46-6	4.49-5	1.71-5
2A, 3A, 5A	3.71-7	6.46-6	4.49-5	1.71-5
5A, 6A	4.24-5	8.48-5	1.63-4	9.54-5
2A, 3A	1.24-8	2.05-7	1.52-6	5.36-7
6A	1.50-8	2.05-7	1.45-6	5.32-7
5A	1.52-8	2.15-7	1.70-6	5.30-7
None	2.14-5	2.93-5	4.14-5	3.00-5

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-2

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling	-	-	-	1.0	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.5-3	1.1-2	6.1-3	1.3.3
R-3	Recirculation Cooling	3.8-5	2.4-4	1.3-3	5.0-4	1.3.3
CF-2	Fan Coolers	1.9-8	7.9-7	1.7-5	5.0-6	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.6-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	5.7-3	1.9-2	6.2-2	2.5-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling	3.7-7	6.5-6	4.5-5	1.7-5	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.7-3	3.5-3	6.7-3	4.1-3	1.3.3
CF-2	Fan Coolers	9.5-4	8.3-3	4.4-2	1.6-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling	4.2-5	8.5-5	1.6-4	9.5-5	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	3.0-3	5.7-3	1.1-2	6.2-3	1.3.3
R-3	Recirculation Cooling	1.4-4	4.4-4	1.6-3	7.0-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-2 (continued)

ET-12b - RT - LOSS OF COMPONENT COOLING

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling	1.5-8	2.1-7	1.5-6	5.3-7	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-2 (continued)

ET-12b - RT - LOSS OF COMPONENT COOLING

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling	1.2-8	2.1-7	1.5-6	5.4-7	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-2 (continued)

ET-12b - RT - LOSS OF COMPONENT COOLING

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling	1.5-8	2.2-7	1.7-6	5.3-7	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling	2.1-5	2.9-5	4.1-5	3.0-5	1.5.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.12b-3

INDIAN POINT 2 REACTOR TRIP, LOSS OF COMPONENT COOLING EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{12B} = [	0	0	0	0	1.89-5	1.53-9	3.29-10	2.66-14	1.19-7	3.98-11	7.44-9	3.94-9	0	0	0	0	0	0	0	0	0]
M'_{12B} = [	NOT REQUIRED																				]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.5.12b-4

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING
EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	1.89-5	2,3,5,6	3	L-1, R-3	1.89-5
SLF	1.53-9	2,3,5,6	5	L-1, R-3, CS	1.53-9
SLC	3.29-10	5,6	6	L-1, R-3, CF-2	3.02-10
SL	2.66-14	5,6	8	L-1, R-3, CF-2, CS	2.45-14
TEFC	1.19-7	2,3,5,6	9	L-1, OP-2	1.16-7
TEF	3.98-11	2,3,5	11	L-1, OP-2, CS	2.72-11
		2,3,5,6	11	L-1, CS	9.39-12
		2,3,6	11	L-1, CS	3.17-12
TEC	7.44-9	5	12	L-1	7.34-9
TE	3.94-9	No Power	14	L-1	3.78-9

Note: Values are presented in abbreviated scientific notation, e.g., 5.39-3 = 5.39×10^{-3}.

1.3.5.13 ATWS--Event Tree 13 (ET-13) Quantification

The ATWS event tree is a continuation of all plant event trees except:

- ET-1 and ET-2, large and medium LOCAs - the reactor is initially shut down by voiding in the core region
- ET-12, reactor trip

Following failure of reactor trip, the other trees branch to the ATWS tree in a particular state of electric power with split fractions shown as M^{β} in Tables 1.3.5.13-4 through 1.3.5.13-13. The branch point split fraction data for the ATWS tree (conditional on ϕ^{I} and electric power state) is developed in Sections 1.3.3 and 1.5.2, and is summarized in Table 1.3.5.13-1.

When mean value data is propagated through the ATWS event tree, the results shown in Table 1.3.5.13-2 are obtained. This 8 x 21 matrix is called M^{α}. Dominant sequences from the ATWS tree with all AC power available, the most likely state, are listed in Table 1.3.5.13-3. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

$M^{\alpha}{}_{1}$ shows the split fractions to each plant event sequence category conditional on an ATWS in an event tree for other than a turbine trip initiating event, and a specific state of electric power. Likewise, $M^{\alpha}{}_{1}$ shows the split fractions to each plant event sequence category conditional on an ATWS in a turbine trip event tree and a specific state of electric power. The results of the ATWS tree quantification, M^{α}, are combined with ATWS results of the applicable plant event trees, M^{β}, in Tables 1.3.5.13-4 through 1.3.5.13-13.

Event PL has been quantified by reviews of the plant trip data from Indian Point Unit 2 and Zion Station Units 1 and 2. The approximate power levels for all losses of main feedwater (ϕ_7) and turbine trips (ϕ_{11}) have been identified. These transients provide most of the input to the ATWS event tree (90% on a mean frequency basis). Based on the Zion Station Units 1 and 2 data (PL > 80% for 48 out of 99 transients) and the plant specific Indian Point Unit 2 data which was consistent with the Zion data, a mean value of 0.5 has been assigned to PL.

TABLE 1.3.5.13-1

ET-13 - FAILURE TO SCRAM

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.5.13
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	3.8-3	7.0-3	1.5-2	8.6-3	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.3-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	6.0-3	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deergized and RCCAs Fall	-	-	-	5.6-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	6.4-3	1.3.3
R-3	Recirculation Cooling	-	-	-	7.0-4	1.3.3
CF-2	Fan Coolers	-	-	-	2.4-4	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.5.13
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	2.8-6	1.1-5	4.7-5	1.9-5	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	3.8-3	7.0-3	1.5-2	8.6-3	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.3-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deergized and RCCAs Fall	-	-	-	5.6-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	5.5-3	1.3.3
CF-2	Fan Coolers	-	-	-	3.8-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.5.13
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	-	-	-	1.3-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.3-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deergized and RCCAs Fall	-	-	-	5.6-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.8-2	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.5.13
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	7.1-3	1.1-2	2.0-2	1.3-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.3-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	6.0-3	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deergized and RCCAs Fall	-	-	-	5.6-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	6.4-3	1.3.3
R-3	Recirculation Cooling	-	-	-	7.9-4	1.3.3
CF-2	Fan Coolers	1.7-3	1.9-2	1.2-1	3.8-2	1.5.2
CS	Containment Spray	4.8-7	9.3-6	1.1-4	8.1-5	1.5.2
NA	NaOH Addition	4.5-4	8.3-4	1.5-3	9.6-4	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.5.13
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	7.1-3	1.1-2	2.0-2	1.3-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.3-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deergized and RCCAs Fall	-	-	-	5.6-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.5.13
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	7.0-5	1.3-4	2.8-4	1.6-4	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	7.1-3	1.1-2	2.0-2	1.3-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.3-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deergized and RCCAs Fall	-	-	-	5.6-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.5.13
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	3.9-3	9.2-3	3.6-2	1.4-2	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	7.1-3	1.6-2	3.1-2	2.1-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.3-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deergized and RCCAs Fall	-	-	-	5.6-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	5.8-3	9.3-3	1.5-2	1.0-2	1.5.2
NA	NaOH Addition	1.5-4	9.9-4	6.4-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.13-1 (continued)

ET-13 - FAILURE TO SCRAM

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.5.13
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	3.9-3	9.7-3	3.6-2	1.4-2	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	-	-	-	1.0	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.3-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deergized and RCCAs Fall	-	-	-	5.6-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.5.13-2

INDIAN POINT 2 ATWS EVENT TREE QUANTIFICATION

1. ATWS Split Fractions Given No Previous Turbine Trip for Specific Electric Power States, M_1^P

PLANT EVENT SEQUENCE CATEGORY

Power at Buses	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
2A, 3A, 5A, 6A	3.27-04	2.66-08	1.08-07	8.75-12	5.89.05	4.77-09	1.41-08	1.15-12	2.33-04	1.89-08	5.59-08	4.53-12	0	0	0	0	0	0	0	0	0
2A, 3A, 6A	4.13-02	4.17-04	1.64-03	1.65-05	2.98-05	2.96-07	1.16-06	1.17-08	3.47-02	3.50-04	1.37-03	1.38-05	0	0	0	0	0	0	0	0	0
2A, 3A, 5A	4.20-02	4.24-04	7.70-04	7.78-06	7.00-03	7.07-05	1.28-04	1.30-06	3.55-02	3.58-04	6.50-04	6.56-06	0	0	0	0	0	0	0	0	0
5A, 6A	3.35-04	2.74-08	1.32-05	1.08-09	6.55-04	5.31-08	2.59-09	2.10-09	2.25-04	1.82-08	8.87-06	7.18-10	0	0	0	0	0	0	0	0	0
2A, 3A	0	0	0	5.04-02	0	0	0	0	0	0	0	3.65-02	0	0	0	0	0	0	0	0	0
6A	0	0	5.16-02	5.04-04	0	0	0	0	0	0	3.61-02	3.65-04	0	0	0	0	0	0	0	0	0
5A	0	0	5.34-02	5.39-04	0	0	0	0	0	0	4.25-02	4.29-04	0	0	0	0	0	0	0	0	0
None	0	0	0	5.05-01	0	0	0	0	0	0	0	4.29-02	0	0	0	0	0	0	0	0	0

2. ATWS Split Fractions Given a Previous Turbine Trip for Specific Electric Power States, M_2^P

PLANT EVENT SEQUENCE CATEGORY

Power at Buses	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
2A, 3A, 5A, 6A	3.26-04	2.65-08	1.07-07	8.67-12	5.83-05	4.76-09	1.41-08	1.14-12	2.33-04	1.89-08	5.59-08	4.53-12	0	0	0	0	0	0	0	0	0
2A, 3A, 6A	4.12-02	4.17-04	1.63-03	1.65-05	2.02-05	2.64-07	1.03-06	1.04-08	3.47-02	3.50-04	1.37-03	1.38-05	0	0	0	0	0	0	0	0	0
2A, 3A, 5A	4.19-02	4.24-04	7.69-04	7.77-05	6.99-03	6.97-05	1.26-04	1.28-06	3.55-02	3.58-04	6.50-04	6.57-06	0	0	0	0	0	0	0	0	0
5A, 6A	3.34-04	2.99-08	1.32-05	1.08-09	6.54-04	5.30-08	2.58-05	2.09-09	2.25-04	1.82-08	8.87-06	7.19-10	0	0	0	0	0	0	0	0	0
2A, 3A	0	0	0	5.02-02	0	0	0	0	0	0	0	3.65-02	0	0	0	0	0	0	0	0	0
6A	0	0	4.97-02	5.02-04	0	0	0	0	0	0	3.61-02	3.65-04	0	0	0	0	0	0	0	0	0
5A	0	0	5.33-02	5.38-04	0	0	0	0	0	0	4.25-02	4.29-04	0	0	0	0	0	0	0	0	0
None (WR)	1.02-02	8.24-07	2.50-06	2.02-12	5.97-05	4.84-09	1.43-08	1.16-12	2.74-04	2.22-08	6.59-08	5.34-12	0	0	0	0	0	0	0	0	0
None	2.44-02	6.01-04	7.30-04	1.00-02	4.22-04	1.04-05	1.26-05	3.10-07	4.06-02	1.00-03	1.21-03	2.99-05	0	0	0	0	0	0	0	0	0

NOTES:

Values are presented in an abbreviated scientific notation, e.g., 1.11-5 - 1.11×10^{-5}

The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior
E - Early melt
L - Late melt
F - Fan coolers re operating
C - Containment sprays are operating

TABLE 1.3.5.13-3

ET-13 - FAILURE TO SCRAM EVENT TREE DOMINANT SEQUENCES
(All AC Power Available)

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences		
		Sequence	Failed Branch Points	Conditional Frequency
SEFC	3.27-4	23	OP-5, OP-6, OP-2	2.29-4
		10	OP-5, PR-2, OP-2	4.86-5
		37	L-2, SO	4.29-5
		30	OP-5, PR-1, SO	3.86-6
SEF	2.66-8	25	OP-5, OP-6, OP-2, CS	1.86-8
		12	OP-5, PR-2, OP-2, CS	3.94-9
		39	L-2, SO, CS	3.48-9
		32	OP-5, PR-1, SO, CS	3.13-10
SEC	1.08-7	26	OP-5, OP-6, OP-2, CF-2	5.50-8
		13	OP-5, PR-2, OP-2, CF-2	1.17-8
		40	L-2, SO, CF-2	1.03-8
		33	OP-5, PR-1, SO, CF-2	9.27-10
		SLOCA	SA-1	2.91-8
SE	8.75-12	28	OP-5, OP-6, OP-2, CF-2, CS	4.46-12
		15	OP-5, PR-2, OP-2, CF-2, CS	9.47-13
		42	L-2, SO, CF-2, CS	8.36-13
		SLOCA	SA-1, CS	2.36-12
SLFC	5.89-5	53	PL, OP-5, OP-6, R-3	2.53-5
		17	OP-5, OP-6, R-3	2.50-5
		4	OP-5, PR-2, R-3	5.28-6
		SLOCA	R-2	3.29-6
SLF	4.77-9	55	PL, OP-5, OP-6, R-3, CS	2.05-9
		19	OP-5, OP-6, R-3, CS	2.02-9
		6	OP-5, PR-2, R-3, CS	4.29-10
		SLOCA	R-2, CS	2.66-10
SLC	1.41-8	56	PL, OP-5, OP-6, R-3, CF-2	6.07-9
		20	OP-5, OP-6, R-3, CF-2	5.98-9
		7	OP-5, PR-2, R-3, CF-2	1.27-9
		SLOCA	CF-1, R-2	7.89-10

Note: Values are presented in abbreviated scientific notation, e.g., 3.27-4 = 3.27×10^{-4}.

TABLE 1.3.5.13-3 (continued)

ET-13 - FAILURE TO SCRAM EVENT TREE DOMINANT SEQUENCES
(All AC Power Available)

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences		
		Sequence	Failed Branch Points	Conditional Frequency
SL	1.15-12	58	PL, OP-5, OP-6, R-3, CF-2, CS	4.92-13
		22	OP-5, OP-6, R-3, CF-2, CS	4.85-13
		9	OP-5, PR-2, R-3, CF-2, CS	1.03-13
		SLOCA	CF-1, R-2, CS	6.39-14
TEFC	2.33-4	59	PL, OP-5, OP-6, OP-2	2.33-4
TEF	1.89-8	61	PL, OP-5, OP-6, OP-2, CS	1.89-8
TEC	5.59-8	62	PL, OP-5, OP-6, OP-2, CF-2	5.58-8
TE	4.53-12	64	PL, OP-5, OP-6, OP-2, CF-2, CS	4.53-12

Note: Values are presented in abbreviated scientific notation, e.g., 1.15-12 = 1.15×10^{-12}.

TABLE 1.3.5.13-4

INDIAN POINT 2 ATWS CONTRIBUTORS TO THE SMALL LOCA EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{β} = [	2.00-5	3.40-10	3.40-10	1.90-9	1.16-11	1.16-11	1.16-11	1.32-12]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	6.57-9	8.18-13	4.22-12	1.27-12	1.18-9	1.20-13	3.26-13	4.73-16	4.68-9	6.19-13	2.73-12	4.96-13	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.5.13-5

INDIAN POINT 2 ATWS CONTRIBUTORS TO THE STEAM GENERATOR TUBE RUPTURE EVENT TREE

(to be supplied)

TABLE 1.3.5.13-6

INDIAN POINT 2 ATWS CONTRIBUTIONS TO THE STEAM LINE BREAK INSIDE CONTAINMENT EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{β} = [	2.00-5	3.40-10	3.40-10	1.90-9	1.16-11	1.16-11	1.16-11	2.51-13

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	6.57-9	8.18-13	4.22-12	7.32-13	1.18-9	1.20-13	3.26-13	4.73-16	4.68-9	6.19-13	2.73-12	4.50-13	0	0	0	0	0	0	0	0	0

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.5.13-7

INDIAN POINT 2 ATWS CONTRIBUTORS TO THE STEAM LINE BREAK OUTSIDE CONTAINMENT EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{β} = [	2.00-5	3.40-10	3.40-10	1.90-9	1.16-11	1.16-11	1.16-11	2.51-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	6.57-9	8.18-13	4.22-12	7.32-13	1.18-9	1.20-13	3.26-13	4.73-16	4.68-9	6.19-13	2.73-12	4.50-13	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.5.13-8

INDIAN POINT 2 ATWS CONTRIBUTIONS TO THE LOSS OF FEEDWATER FLOW EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^B = [	2.00-5	3.40-10	3.40-10	1.90-9	1.16-11	1.16-11	1.16-11	2.51-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^B \cdot M^a$ = [	6.57-9	8.18-13	4.22-12	7.32-13	1.18-9	1.20-13	3.26-13	4.73-16	4.68-9	6.19-13	2.73-12	4.50-13	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.5.13-9

INDIAN POINT 2 ATWS CONTRIBUTORS TO THE LOSS OF PRIMARY FLOW EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{β} = [	1.80-5	3.06-10	3.06-10	1.71-9	1.04-11	1.04-11	1.04-11	2.26-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	5.91-9	7.36-13	3.80-12	6.57-13	1.06-9	1.08-13	2.93-13	4.26-16	4.22-9	5.57-13	2.46-12	4.04-13	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.5.13-10

INDIAN POINT 2 ATWS CONTRIBUTORS TO THE CORE POWER EXCURSION EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^B = [	7.00-12	1.19-16	1.19-16	6.65-16	4.06-18	4.06-11	4.06-18	8.78-20

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^B \cdot M^a$ = [	2.30-15	2.86-19	1.48-18	2.56-19	4.14-16	4.19-20	1.14-19	1.66-22	1.64-15	2.17-19	9.57-19	1.58-19	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.5.13-11

INDIAN POINT 2 ATWS CONTRIBUTORS TO THE TURBINE TRIP EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{β} = [	2.00-5	3.40-10	3.40-10	1.90-9	1.16-11	1.16-11	1.16-11	1.32-12]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	6.55-9	8.17-13	4.18-12	6.40-13	1.18-9	1.19-13	3.74-13	4.66-16	4.68-9	6.20-13	2.74-12	4.40-13	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.5.13-12

INDIAN POINT 2 ATWS CONTRIBUTIONS TO THE TURBINE TRIP (LOSS OF OFFISTE POWER) EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None WR	ATWS and None
M^{β} = [	3.32-6	1.56-7	1.56-7	1.56-7	3.80-9	3.80-9	3.80-9	3.34-9	4.56-10]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	1.41-8	1.32-10	7.68-10	2.14-10	1.38-9	1.09-11	2.39-11	2.02-13	1.18-8	1.11-10	6.16-10	1.45-10	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.5.13-13

INDIAN POINT 2 ATWS CONTRIBUTORS TO THE TURBINE TRIP (LOSS OF SERVICE WATER) EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and None
M^B = [	2.00-5	1.29-9]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^B \cdot M^a$ = [	0	0	6.52-9	6.07-10	0	0	1.68-6	1.36-10	0	0	4.66-9	5.57-11	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

1.3.5.14 Tabulated Results

Sections 1.3.5.1 through 1.3.5.12 provided the conditional split fractions without the ATWS contribution from each initiating event. That information from Tables 1.3.5 (1 through 12)-3 is summarized into the single matrix M (nonATWS) in Table 1.3.5.14-1.

Section 1.3.5.13 provided conditional split fractions via ATWS from each initiating event. That information from Tables 1.3.5.13-4 through 1.3.5.13-13 is summarized into the single matrix M (ATWS) in Table 1.3.5.14-2.

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TABLE 1.3.5.14-1

INDIAN POINT 2 CONTRIBUTION OF ALL NONATWS SEQUENCES

NonATWS Contributions to Conditional Plant Split Fractions, M (NonAWTS)

Initiating Event	Plant Event Sequence Category																			
	SECF	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL
$\ddot{t}_1$ Large LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	2.80-03	2.54-07	6.76-06	8.16-07	5.39-03	4.53-07	1.18-07	3.84-10
$\ddot{t}_2$ Medium LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	1.28-03	1.35-07	7.30-06	8.21-07	5.40-03	4.54-07	9.68-08	1.77-10
$\ddot{t}_3$ Small LOCA:	1.90-04	3.95-08	7.25-06	8.21-07	6.97-04	2.26-07	4.83-09	2.48-11	0	0	0	0	0	0	0	0	0	0	0	0
$\ddot{t}_4$ Steam Generator Tube Rupture:	0	0	0	0	0	0	0	0	3.31-06	1.65-09	1.05-06	8.21-07	0	0	0	0	0	0	0	0
$\ddot{t}_5$ Steam Break Inside Containment:	0	0	0	0	7.46-06	6.05-10	7.54-11	6.10-15	9.41-05	1.26-08	3.43-08	1.63-08	0	0	0	0	0	0	0	0
$\ddot{t}_6$ Steam Break Outside Containment:	0	0	0	0	7.46-06	6.05-10	7.54-11	6.10-15	9.41-05	1.26-08	3.43-08	1.63-08	0	0	0	0	0	0	0	0
$\ddot{t}_7$ Loss of Main Feedwater:	0	0	0	0	9.47-09	7.67-13	4.49-13	3.64-17	1.19-07	3.93-11	7.48-09	3.94-09	0	0	0	0	0	0	0	0
$\ddot{t}_8$ Trip of One MSIV:	0	0	0	0	9.47-09	7.67-13	4.49-13	3.64-17	1.19-07	3.93-11	7.48-09	3.94-09	0	0	0	0	0	0	0	0
$\ddot{t}_9$ Loss of RCS Flow:	0	0	0	0	8.52-09	6.91-13	4.04-13	3.27-17	1.07-07	3.54-11	6.74-09	3.55-09	0	0	0	0	0	0	0	0
$\ddot{t}_{10}$ Core Power Excursion:	0	0	0	0	3.31-15	2.68-19	1.57-19	1.27-23	4.16-14	1.38-17	2.62-15	1.38-15	0	0	0	0	0	0	0	0
$\ddot{t}_{11a}$ Turbine Trip:	0	0	0	0	9.45-09	7.66-13	4.49-13	3.64-17	1.19-07	3.93-11	7.48-09	3.94-09	0	0	0	0	0	0	0	0
$\ddot{t}_{11b}$ Turbine Trip, Loss of Offsite Power:	1.78-04	1.45-08	2.18-05	5.56-06	8.57-07	3.70-10	3.75-10	1.32-12	7.92-07	7.51-10	1.20-09	1.19-11	0	0	0	0	0	0	0	0
$\ddot{t}_{11c}$ Turbine Trip, Loss of Service Water:	0	0	0	0	0	0	1.89-5	1.53-9	0	0	1.16-7	1.82-6	0	0	0	0	0	0	0	0
$\ddot{t}_{12a}$ Reactor Trip:	0	0	0	0	9.47-09	7.67-13	4.49-13	3.64-17	1.19-07	3.93-11	7.49-09	3.94-09	0	0	0	0	0	0	0	0
$\ddot{t}_{12b}$ Reactor Trip - Loss of Component Cooling Water:	0	0	0	0	1.89-5	1.53-9	3.29-10	2.66-14	1.19-7	3.89-11	7.44-9	3.94-9	0	0	0	0	0	0	0	0
$\ddot{t}_V$ Interfacing Systems LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

NOTES:

Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior E - Early melt F - Fan Coolers are operating
T - Transient behavior L - Late melt C - Containment sprays are operating

TABLE 1.3.5.14-2

INDIAN POINT 2 CONTRIBUTION OF ALL ATWS SEQUENCES

ATWS Contributions to Conditional Plant Split Fractions, M (ATWS)

Initiating Event	Plant Event Sequence Category																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	VE
ϕ_1 Large LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_2 Medium LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_3 Small LOCA:	1.23-07	1.01-11	1.62-12	2.81-12	4.96-09	4.15-13	1.02-11	5.38-12	3.95-10	4.89-14	1.64-13	8.04-14	0	0	0	0	0	0	0	0	0
ϕ_4 Steam Generator Tube Rupture:	1.65-11	1.35-15	2.71-13	2.88-12	6.62-13	5.64-17	1.04-11	5.48-12	5.29-14	7.73-18	1.28-13	8.17-14	0	0	0	0	0	0	0	0	0
ϕ_5 Steam Break Inside Containment:	1.23-07	1.01-11	1.62-12	6.34-13	4.96-09	4.15-13	1.02-11	5.38-12	3.95-10	4.89-14	1.64-13	3.91-14	0	0	0	0	0	0	0	0	0
ϕ_6 Steam Break Outside Containment:	1.23-07	1.01-11	1.62-12	6.34-13	4.96-09	4.15-13	1.02-11	5.38-12	3.95-10	4.89-14	1.64-13	3.91-14	0	0	0	0	0	0	0	0	0
ϕ_7 Loss of Main Feedwater:	1.23-07	1.01-11	1.62-12	6.34-13	4.96-09	4.15-13	1.02-11	5.38-12	3.95-10	4.89-14	1.64-13	3.91-14	0	0	0	0	0	0	0	0	0
ϕ_8 Trip of One MSIV:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_9 Loss of RCS Flow:	1.11-07	9.09-12	1.45-12	5.69-13	4.46-09	3.73-13	9.26-12	4.84-12	3.56-10	4.40-14	1.48-13	3.51-14	0	0	0	0	0	0	0	0	0
ϕ_{10} Core Power Excursion	4.33-14	3.53-18	5.67-19	2.21-19	1.73-15	1.45-19	3.60-18	1.88-18	1.38-16	1.71-20	5.75-20	1.36-20	0	0	0	0	0	0	0	0	0
ϕ_{11a} Turbine Trip:	1.23-07	1.01-11	1.62-12	2.81-12	4.96-09	4.15-13	1.02-11	5.38-12	3.95-10	4.89-14	1.64-13	8.04-14	0	0	0	0	0	0	0	0	0
ϕ_{11b} Turbine Trip, Loss of Offsite Power:	1.89-06	1.67-09	9.94-09	1.97-09	8.72-10	7.28-14	2.05-12	2.33-16	1.64-07	1.52-09	6.92-09	1.96-09	0	0	0	0	0	0	0	0	0
ϕ_{11c} Turbine Trip, Loss of Service Water:	0	0	1.24-7	2.57-10	0	0	9.92-6	8.04-10	0	0	3.94-10	4.56-11	0	0	0	0	0	0	0	0	0
ϕ_{12a} Reactor Trip:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_{12b} Reactor Trip - Loss of Component Cooling Water:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_V Interfacing Systems LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

NOTES:

Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

The Plant Event Sequence Categories are defined in Section 1.3.5.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior E - Early melt F - Fan coolers are operating
T - Transient behavior L - Late melt C - Containment sprays are operating

1.3.6 INDIAN POINT 3 EVENT TREE QUANTIFICATION

1.3.6.1 Large LOCA--Event Tree 1 Quantification

1.3.6.1.1 Base Case Quantification

The frequency of the large LOCA initiating event, ϕ_1, is developed in Section 1.6.1 and shown with the electric power state split fraction data (conditional on ϕ_1) in Table 1.3.6.1-1. The other branch point split fraction data for the event tree (conditional on ϕ_1 and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.1-2.

When mean value data is propagated through the large LOCA event tree, the base case results displayed in Table 1.3.6.1-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

Dominant sequences are listed in Table 1.3.6.1-4. Those that are shown to be dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be quantified to properly account for uncertainty.

1.3.6.1.2 Large LOCA Beyond ECCS Capability

Two classes of large LOCA possibly beyond ECCS capability have been identified. They are simultaneous ruptures of two or more large pipes, and very large reactor vessel ruptures.

Independent simultaneous large ruptures are so unlikely that they cannot be major contributors to risk. Dependent large ruptures resulting from external events, such as seismic, are considered in Section 7. No internal dependencies (e.g., pipe whip damage following a large LOCA) that would contribute substantially to Indian Point 3 risk have been identified.

Reactor vessel ruptures that are beyond the capability of ECCS were analyzed in WASH-1400 (Reference 1.3-17) based on a 1974 ACRS report (Reference 1.3-18). The WASH-1400 estimate of the frequency of such failures is lognormal with:

5th Percentile:	10^{-8}/year
Median:	10^{-7}/year
95th Percentile:	10^{-6}/year

Even with these conservative estimates, the frequency of catastrophic vessel rupture is small compared to the mean frequency of damaged core states due to a large LOCA (i.e., a large LOCA followed by failure of LP-1 or R-1), 6.2×10^{-6} per year. Furthermore, this event differs only slightly from other large LOCAs in its effects on containment

except for the possible generation of missiles which could cause containment failure. A review of a series of such possible missiles, including control rod drive mechanisms and the upper vessel head, results in the conclusion that failure by such mechanisms has an extremely small probability. Therefore, the large LOCA beyond ECCS capability leads to the same plant event sequence categories as those resulting from other large LOCAs with failure of safety injection.

Plant Event Sequence Category	System Failure Responsible For Core Melt	CF*	CS*
AEFC	Large LOCA Beyond ECCS Capability (early melt)	1	1
AEF		1	0
AEC		0	1
AE		0	0

*1 = Success
0 = Failure

Because the frequency is small compared to that resulting from other large LOCAs combined with failure of safety injection, it is not tabulated separately from the large LOCA results in Table 1.3.6.1-3.

1.3.6.1.3 LOCA Paths Outside Containment

Event V, as described in the RSS, WASH-1400, involves the disc rupture or the disc failing open of two series check valves in one of the three separate LPI lines of the plant studied. This event results in a large LOCA that bypasses the containment, loss of water outside of containment that would normally be injected through the LPI lines, and loss of the LPR mode of core cooling.

The failure modes of interest for the events in this study are:

1. Rupture of a valve disc at less than design pressure.

2. Failure of a motor-operated valve to close due to disengagement of the gear drive from the valve stem. This failure mode results in a valve which indicates closed due to the operation of the valve limit switches which control valve operation and indication, even though the valve disc has not closed due to the disengagement of the gear drive from the valve stem.

In order to determine the frequencies of the identified failure modes, an extensive data search was conducted (see References 1.3-28 and 1.3-29). The assumptions used for quantifying each failure mode and the results of that quantification are presented in the following paragraphs.

- Assumptions

  - Reactor critical hours reflect the exposure hours at high pressure for high pressure/low pressure boundary valves.

  - The rupture failure mode also includes excessive leakage (in excess of relief device capacity).

  - For the rupture failure mode, the discs of check valves and gate valves are treated as members of the same population. Failure of motor-operated or check valves to close fully, while resulting in excessive leakage, is not included in this failure mode because:

    - All the boundary check valves of interest for the interfacing system LOCA are tested after every cold shutdown to ensure that the valves are fully seated.

    - Failure of a motor-operated valve to fully seat is included in the frequency of failure for the other failure mode of interest (failure to close).

- Quantification. For each pressurized water reactor (PWR), the total number of reactor critical hours was determined based on data through December 31, 1981 (Reference 1.3-29). For each PWR, the number of high pressure/low pressure boundary valves was then determined as follows:

  - The number of low pressure injection (LPI) paths into the reactor coolant system (RCS) was determined from the plant descriptions in Reference 1.3-28.

  - The number of hot leg suction paths from the RCS to the residual heat removal (RHR) system was determined from the plant descriptions in Reference 1.3-28.

  - If the low pressure injection paths were shared by the accumulator injection system, and if it could be determined from Reference 1.3-28 or other sources of information that the low pressure injection paths were normally lined up from the RHR/LPI pumps to the RCS (i.e., no closed motor-operated valves), then the second check valve in the double check valve arrangement was included as a boundary valve. Figure 1.3.6.1-1, the Indian Point 3 cold leg injection path, is representative of this arrangement.

  The total number of boundary valves for each plant was then multiplied by the total number of reactor critical hours to determine the total number of exposure hours at pressure for each plant. These data were then updated using plant specific data to determine the frequency of valve disc rupture for each plant. The

distribution associated with valve disc rupture for Indian Point 3 is described by:

5th Percentile:	1.35×10^{-10}/hour
Median:	2.67×10^{-9}/hour
95th Percentile:	5.28×10^{-8}/hour
Mean:	1.38×10^{-8}/hour

The "MOV fails to close (indicates closed)" failure mode is a subset of the larger failure category "failure to operate on demand." Nuclear Power Experience (Reference 1.3-28) was reviewed to determine the total number of MOV failures to operate on demand and the number of failures to close or open with indication of closed or open, respectively. Using a beta distribution model, a distribution for the number of failures of interest divided by the total number of observed failures was obtained. The distribution for this fraction is described by:

5th Percentile:	1.58×10^{-2}
Median:	2.46×10^{-2}
95th Percentile:	3.46×10^{-2}
Mean:	2.49×10^{-2}

This value was multiplied by the plant specific frequency of failure of MOVs to operate on demand. The resulting distribution represents the frequency of "MOV fails to close but indicates closed" for Indian Point 3. This distribution is described by:

5th Percentile:	5.80×10^{-6}
Median:	2.60×10^{-5}
95th Percentile:	1.11×10^{-4}
Mean:	3.76×10^{-5}

1.3.6.1.3.1 Cold Leg Injection Path Interfacing System LOCA. Referring to Figure 1.3.6.1-1, the cold leg injection paths at Indian Point 3 are similar to the paths described for Indian Point 2. Two normally open MOVs in each of two paths form a boundary between the high and low pressure portions of the cold leg injection paths, because they can be closed by the operator in the event of an accident. Conservatively, no credit is taken for this potential operator action in the quantification which follows.

Using the equation for the average failure rate of two valves in sequence developed in Section 1.3.5.1.3.1 and the distribution for the frequency of check valve failure given on page 1.3-448, the frequency of failure of a single cold leg injection check valve path per reactor year is:

5th Percentile:	3.48×10^{-16}
Median:	3.39×10^{-12}
95th Percentile:	4.11×10^{-8}
Mean:	6.56×10^{-8}

The frequency of failure of any one of the four paths is:

5th Percentile:	1.39×10^{-15}
Median:	1.36×10^{-11}
95th Percentile:	1.64×10^{-7}
Mean:	2.62×10^{-7}

1.3.6.1.3.2 Hot Leg Suction Path Interfacing System LOCA. Referring to Figure 1.3.6.1-2, the hot leg path is similar to that described for Indian Point 2. The same failure modes and equations apply.

The frequency of interfacing system LOCA due to rupture of both normally closed MOVs in the hot leg suction path is:

5th Percentile:	1.56×10^{-15}
Median:	1.52×10^{-11}
95th Percentile:	1.84×10^{-7}
Mean:	2.95×10^{-7}

The frequency of an interfacing system LOCA due to the rupture/open failure mode is:

5th Percentile:	2.89×10^{-12}
Median:	2.11×10^{-10}
95th Percentile:	3.26×10^{-8}
Mean:	9.11×10^{-9}

1.3.6.1.3.3 Interfacing System LOCA. The frequency of an interfacing system LOCA at Indian Point 3 is the sum of the frequencies of the

individual failure paths previously described. This sum is as follows:

5th Percentile:	2.96×10^{-12}
Median:	2.60×10^{-10}
95th Percentile:	4.03×10^{-7}
Mean:	5.66×10^{-7}

Figure 1.3.6.1-3 presents the distribution of the interfacing system LOCA frequency for Indian Point 3. Note that rupture of two sequential check valves in the cold leg and rupture of both MOVs in the hot leg each contribute about half of the total mean frequency, while the rupture/open event contributes only a small fraction of the total.

1.3.6.1.3.4 Mitigating Features. Several plant features could mitigate the consequences of an Event V through one of the LPI cold legs.

- Each LPI line contains two motor-operated isolation valves that are normally open. They are designed to withstand full RCS pressure and serve as the boundary between the high and low pressure piping of the LPI system. Given an Event V scenario, a safeguard actuation signal is set to open these valves. This signal will prevent these valves from closing until it is reset (approximately 3 minutes). After the signal is reset, the plant control room operators may close the valves. Once they are closed, the cold leg Event V scenario is terminated.

- Each LPI line contains a relief valve set at 600 psig with the discharge routed to the pressurizer relief tank inside the containment. The combined capacity of the two relief valves is sufficient to relieve substantial leakage resulting from an Event V scenario. Both relief valves would be expected to lift since the piping is normally crossconnected.

In addition, the RHR suction line contains a relief valve set at 600 psig with the discharge routed to the pressurizer relief tank. This relief valve and the overstress capabilities of the low pressure piping could mitigate the consequences of an RHR suction line Event V scenario.

1.3.6.1.3.5 Conservatism in the Results. The results of the interfacing system LOCA quantification are controlled by the frequency of valve disc rupture while exposed to normal RCS pressure. An extensive data search revealed no ruptures of any valve disc in a nuclear power system. Discussion with representative valve manufacturers revealed no failures of this type in their experience (including experience in process plants and conventional steam plants); see Reference 1.3-30.

TABLE 1.3.6.1-1

LARGE LOCA INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_1- Large LOCA (Annual Frequency)	1.07-6	1.17-4	6.66-3	2.16-3
AC Power Available at Buses (Given ϕ_1):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation; e.g., 1.07-6 = 1.07×10^{-6}.

TABLE 1.3.6.1-2

ET-1 - LARGE LOCA

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-1	Large LOCA	-	-	-	1.0	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-1	Low Pressure Injection/ Accumulators	-	-	-	3.0-3	1.3.3
CS	Containment Spray Actuation/Injection	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	Sodium Hydroxide Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2
CF-1	RC Fan Coolers	4.6-9	9.1-8	1.7-6	6.3-7	1.6.2
R-1	Low Head Recirculation	5.0-5	2.1-3	1.4-2	5.3-3	1.3.3
RS	Recirculation Spray	5.5-5	5.5-4	5.5-3	1.5-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.1-2 (continued)

ET-1 - LARGE LOCA

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-1	Large LOCA	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-1	Low Pressure Injection/ Accumulators	-	-	-	3.0-3	1.3.3
CS	Containment Spray Actuation/Injection	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	Sodium Hydroxide Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
CF-1	RC Fan Coolers	1.3-3	2.5-3	4.8-3	2.8-3	1.6.2
R-1	Low Head Recirculation	1.9-3	2.3-2	1.1-1	4.4-2	1.3.3
RS	Recirculation Spray	4.0-4	2.0-3	7.0-3	3.0-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.1-2 (continued)

ET-1 - LARGE LOCA

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-1	Large LOCA	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-1	Low Pressure Injection/ Accumulators	-	-	-	5.3-3	1.3.3
CS	Containment Spray Actuation/Injection	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	Sodium Hydroxide Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
CF-1	RC Fan Coolers	6.0-7	2.1-6	9.7-6	3.9-6	1.6.2
R-1	Low Head Recirculation	1.9-3	2.3-2	1.1-1	4.4-2	1.3.3
RS	Recirculation Spray	4.0-4	2.0-3	7.0-3	3.0-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.1-2 (continued)

ET-1 - LARGE LOCA

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-1	Large LOCA	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-1	Low Pressure Injection/ Accumulators	-	-	-	5.3-3	1.3.3
CS	Containment Spray Actuation/Injection	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	Sodium Hydroxide Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2
CF-1	RC Fan Coolers	1.3-3	2.5-3	4.8-3	2.8-3	1.6.2
R-1	Low Head Recirculation	2.6-4	7.5-3	1.1-1	3.9-2	1.3.3
RS	Recirculation Spray	5.5-5	5.5-4	5.5-3	1.5-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.1-2 (continued)

ET-1 - LARGE LOCA

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-1	Large LOCA	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-1	Low Pressure Injection/ Accumulators	-	-	-	5.3-3	1.3.3
CS	Containment Spray Actuation/ Injection	-	-	-	1.0	1.6.2
NA	Sodium Hydroxide Addition	-	-	-	1.0	1.6.2
CF-1	RC Fan Coolers	-	-	-	1.0	1.6.2
R-1	Low Head Recirculation	-	-	-	1.0	1.3.3
RS	Recirculation Spray	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.1-2 (continued)

ET-1 - LARGE LOCA

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-1	Large LOCA	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-1	Low Pressure Injection/ Accumulators	-	-	-	5.3-3	1.3.3
CS	Containment Spray Actuation/ Injection	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	Sodium Hydroxide Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
CF-1	RC Fan Coolers	-	-	-	1.0	1.6.2
R-1	Low Head Recirculation	1.9-3	2.3-2	1.1-1	4.4-2	1.3.3
RS	Recirculation Spray	4.0-4	2.0-3	7.0-3	3.0-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.1-2 (continued)

ET-1 - LARGE LOCA

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-1	Large LOCA	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-1	Low Pressure Injection/ Accumulators	-	-	-	1.0	1.3.3
CS	Containment Spray Actuation/ Injection	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	Sodium Hydroxide Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
CF-1	RC Fan Coolers	-	-	-	1.0	1.6.2
R-1	Low Head Recirculation	1.9-3	2.3-2	1.1-1	4.4-2	1.3.3
RS	Recirculation Spray	4.0-4	2.0-3	7.0-3	3.0-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.1-2 (continued)

ET-1 - LARGE LOCA

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-1	Large LOCA	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-1	Low Pressure Injection/ Accumulators	-	-	-	1.0	1.3.3
CS	Containment Spray Actuation/Injection	-	-	-	1.0	1.6.2
NA	Sodium Hydroxide Addition	-	-	-	1.0	1.6.2
CF-1	RC Fan Coolers	-	-	-	1.0	1.6.2
R-1	Low Head Recirculation	-	-	-	1.0	1.3.3
RS	Recirculation Spray	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.1-3

INDIAN POINT 3 LARGE LOCA EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_1 =	0	0	0	0	0	0	0	0	0	0	0	0	3.01-3	1.33-7	7.19-6	1.26-7	5.34-3	1.97-7	1.87-7	3.78-7	0
M_1' =	NOT REQUIRED																				

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.1-4

ET-1 - LARGE LOCA EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
AEFC	3.01-3	2,3,5,6	13	LP-1	2.98-3
AEF	1.33-7	2,3,5,6 2,3,5,6	25 34	LP-1, CS TK	1.08-7 2.40-8
AEC	7.19-6	2,3,5,6 5,6	27 16	SA-1 LP-1, CF-1	6.15-6 9.10-7
AE	1.26-7	No Power	26		1.20-7
ALFC	5.34-3	2,3,5,6	2	R-1	5.29-3
ALF	1.97-7	2,3,5,6	10	CS, R-1	1.90-7
ALC	1.87-7	5,6 6	4 4	CF-1, R-1 R-1	1.63-7 1.87-8
AL	3.78-7	2,3	12		3.78-7

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

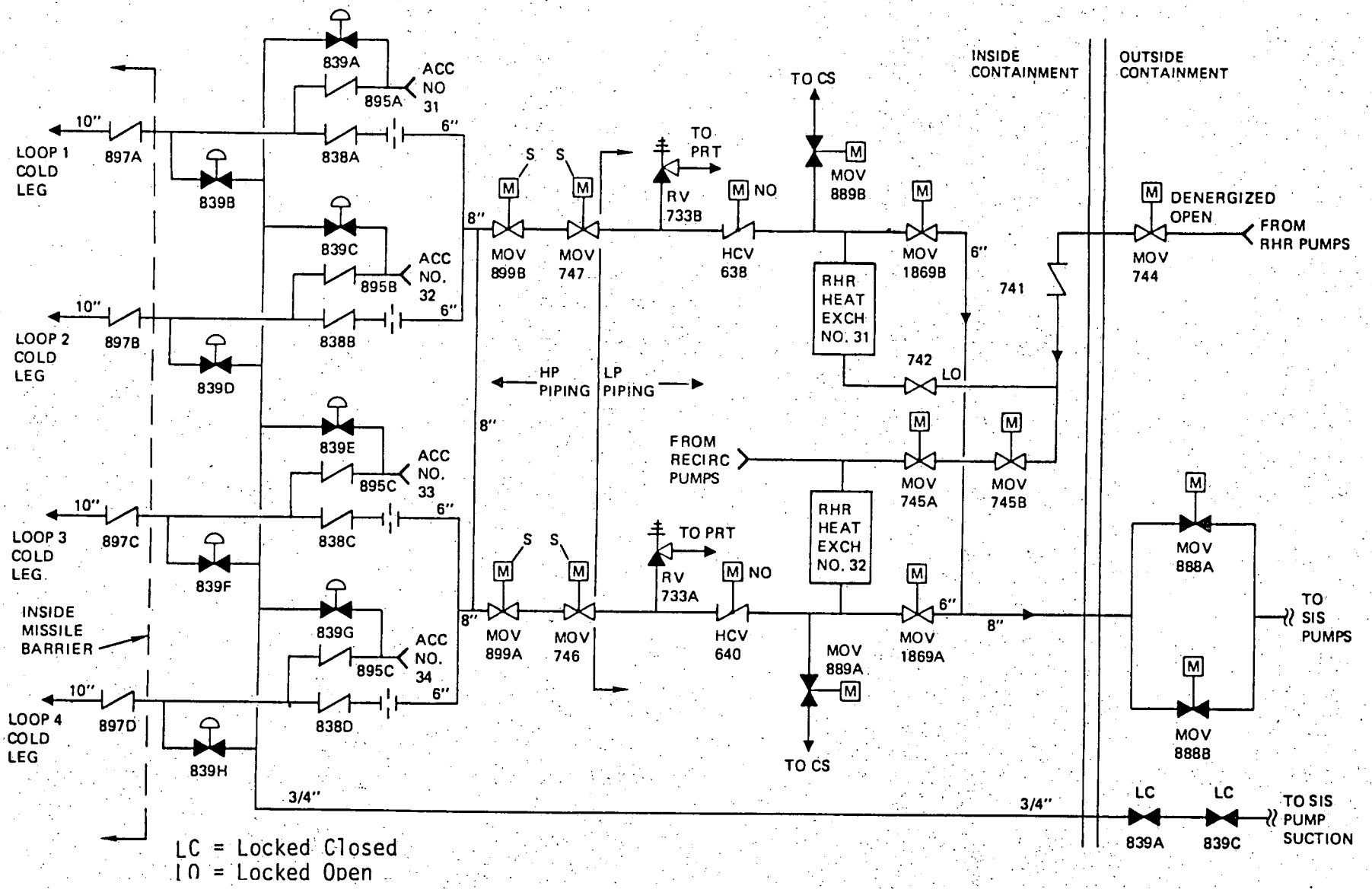

Figure 1.3.6.1-1. Indian Point 3 Cold Leg Injection Path

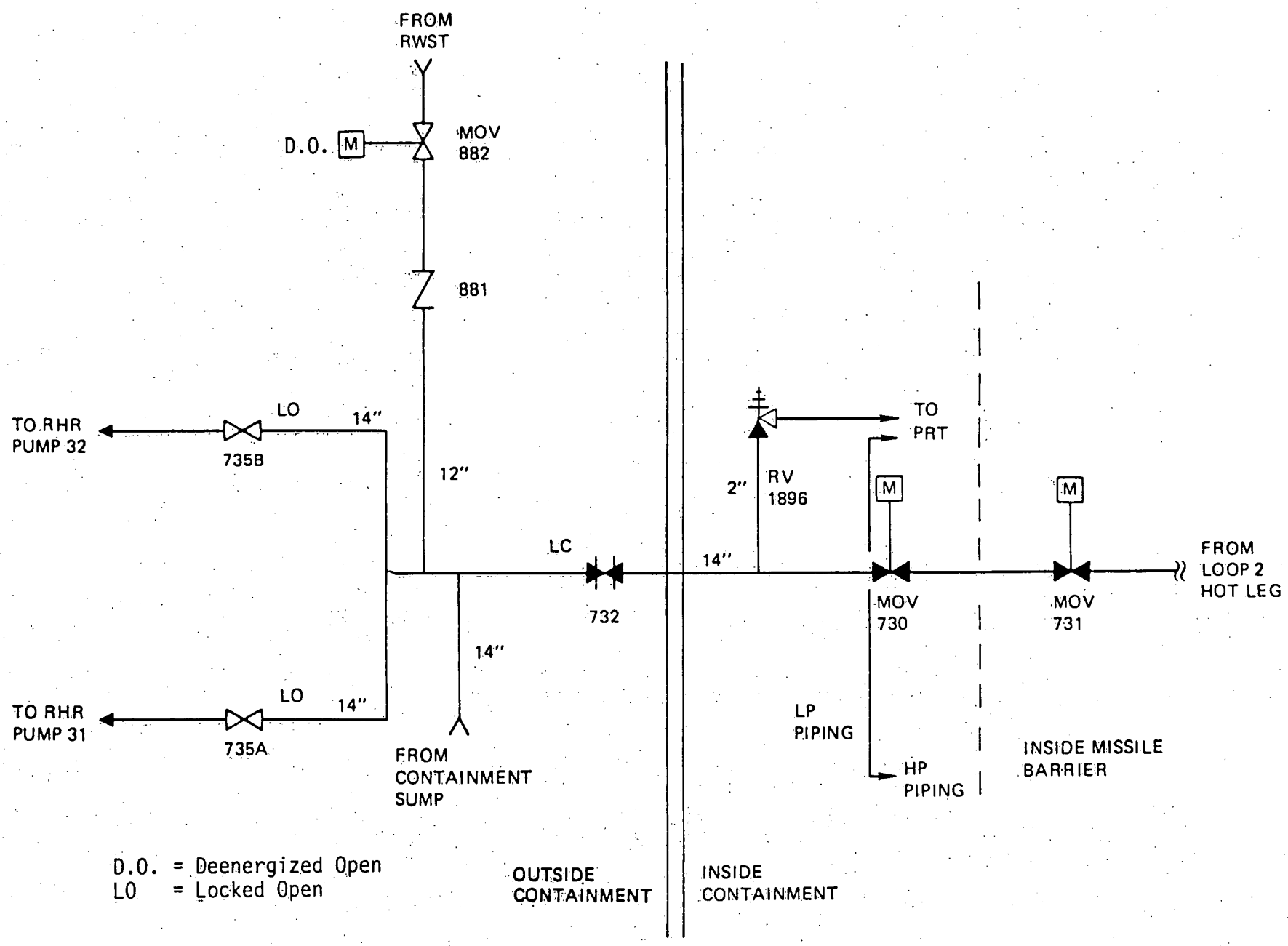

Figure 1.3.6.1-2. Indian Point 3 RHR Suction Path

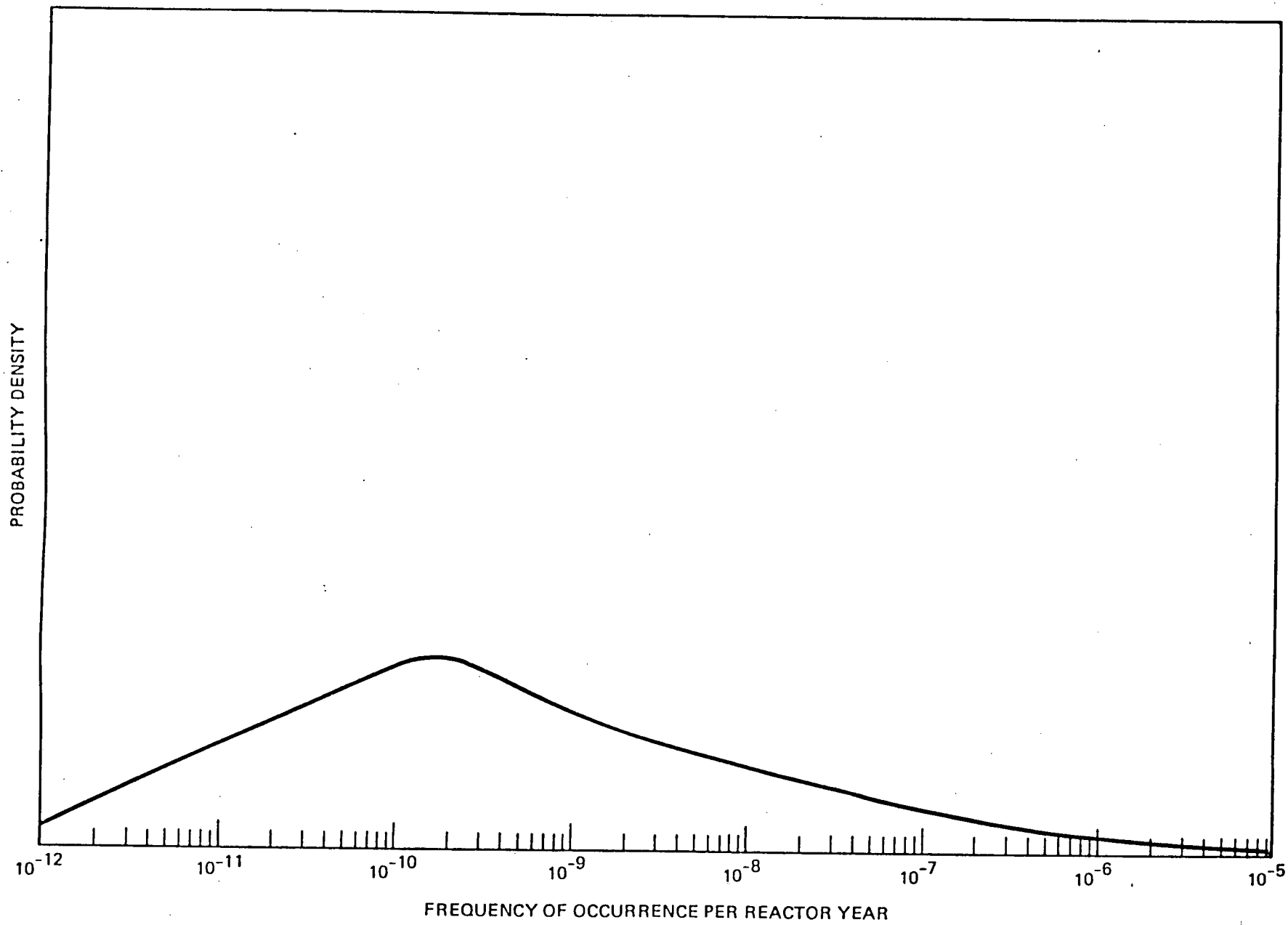

Figure 1.3.6.1-3. Indian Point 3 Results, Interfacing System LOCA

1.3.6.2 Medium LOCA--Event Tree 2 (ET-2) Quantification

The frequency of the medium LOCA initiating event, ϕ_2, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_2) in Table 1.3.6.2-1. The other branch point split fraction data for the event tree (conditional on ϕ_2 and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.2-2.

When mean value data is propagated through the medium LOCA event tree, the base case results shown in Table 1.3.6.2-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

Dominant sequences are listed in Table 1.3.6.2-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.2-1

MEDIUM LOCA INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_2- Medium LOCA (Annual Frequency)	1.07-6	1.17-4	6.66-3	2.16-3
AC Power Available at Buses (Given ϕ_2):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-2

ET-2 - MEDIUM LOCA

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-2	Medium LOCA	-	-	-	1.0	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-2	Low Pressure Injection	-	-	-	8.1-4	1.3.3
HH-1	High Head Injection	6.4-5	1.5-4	5.5-4	1.8-4	1.3.3
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2
CF-1	Fan Coolers	4.6-9	9.1-8	1.7-6	6.3-7	1.6.2
R-1	Recirculation Suction Lineup	5.0-5	2.1-3	1.4-2	5.3-3	1.3.3
RS	Containment Spray Recirculation	5.5-5	5.5-4	5.5-3	1.5-3	1.3.3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-2 (continued)

ET-2 - MEDIUM LOCA

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-2	Medium LOCA	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-2	Low Pressure Injection	-	-	-	8.1-4	1.3.3
HH-1	High Head Injection	3.1-3	6.1-3	1.6-2	7.1-3	1.3.3
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.1
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.1
CF-1	Fan Coolers	1.3-3	2.5-3	4.8-3	2.8-3	1.6.1
R-1	Recirculation Suction Lineup	1.9-3	2.3-2	1.1-1	4.4-2	1.3.3
RS	Containment Spray Recirculation	4.0-4	2.0-3	7.0-3	3.0-3	1.3.3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-2 (continued)

ET-2 - MEDIUM LOCA

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-2	Medium LOCA	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-2	Low Pressure Injection	-	-	-	3.1-3	1.3.3
HH-1	High Head Injection	3.1-3	6.1-3	1.6-2	7.1-3	1.3.3
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
CF-1	Fan Coolers	6.0-7	2.1-6	9.7-6	3.9-6	1.6.2
R-1	Recirculation Suction Lineup	1.9-3	2.3-2	1.1-1	4.4-2	1.3.3
RS	Containment Spray Recirculation	4.0-4	2.0-3	7.0-3	3.0-3	1.3.3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-2 (continued)

ET-2 - MEDIUM LOCA

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-2	Medium LOCA	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-2	Low Pressure Injection	-	-	-	3.1-3	1.3.3
HH-1	High Head Injection	1.8-3	3.4-3	8.6-3	3.9-3	1.3.3
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2
CF-1	Fan Coolers	1.3-3	2.5-3	4.8-3	2.8-3	1.6.2
R-1	Recirculation Suction Lineup	2.6-4	7.5-3	1.1-1	3.9-2	1.3.3
RS	Containment Spray Recirculation	5.5-5	5.5-4	5.5-3	1.5-3	1.3.3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-2 (continued)

ET-2 - MEDIUM LOCA

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-2	Medium LOCA	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-2	Low Pressure Injection	-	-	-	3.1-3	1.3.3
HH-1	High Head Injection	-	-	-	1.0	1.3.3
CS	Containment Spray	-	-	-	1.0	1.6.1
NA	NaOH Addition	-	-	-	1.0	1.6.1
CF-1	Fan Coolers	-	-	-	1.0	1.6.1
R-1	Recirculation Suction Lineup	-	-	-	1.0	1.3.3
RS	Containment Spray Recirculation	-	-	-	1.0	1.3.3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-2 (continued)

ET-2 - MEDIUM LOCA

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-2	Medium LOCA	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-2	Low Pressure Injection	-	-	-	3.1-3	1.3.3
HH-1	High Head Injection	-	-	-	1.0	1.3.3
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
CF-1	Fan Coolers	-	-	-	1.0	1.6.2
R-1	Recirculation Suction Lineup	1.9-3	2.3-2	1.1-1	4.4-2	1.3.3
RS	Containment Spray Recirculation	4.0-4	2.0-3	7.0-3	3.0-3	1.3.3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-2 (continued)

ET-2 - MEDIUM LOCA

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-2	Medium LOCA	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-2	Low Pressure Injection	-	-	-	1.0	1.3.3
HH-1	High Head Injection	-	-	-	1.0	1.3.3
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
CF-1	Fan Coolers	-	-	-	1.0	1.6.2
R-1	Recirculation Suction Lineup	1.9-3	2.3-2	1.1-1	4.4-2	1.3.3
RS	Containment Spray Recirculation	4.0-4	2.0-3	7.0-3	3.0-3	1.3.3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-2 (continued)

ET-2 - MEDIUM LOCA

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-2	Medium LOCA	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
LP-2	Low Pressure Injection	-	-	-	1.0	1.3.3
HH-1	High Head Injection	-	-	-	1.0	1.3.3
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2
CF-1	Fan Coolers	-	-	-	1.0	1.6.2
R-1	Recirculation Suction Lineup	-	-	-	1.0	1.3.3
RS	Containment Spray Recirculation	-	-	-	1.0	1.3.3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.2-3

INDIAN POINT 3 MEDIUM LOCA EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_2 =	0	0	0	0	0	0	0	0	0	0	0	0	1.00-3	6.10-8	7.62-6	5.06-7	5.35-3	1.97-7	1.68-7	1.23-11	0
M'_2 =	NOT REQUIRED																				

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.6.2-4

ET-2 - MEDIUM LOCA EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
AEFC	1.00-3	2,3,5,6	31	LP-2	8.03-4
		2,3,5,6	13	HH-1	1.78-4
AEF	6.10-8	2,3,5,6	43	LP-2, CS	2.90-8
		2,3,5,6	70	TK	2.40-8
		2,3,5,6	25	HH-1, CS	6.43-9
AEC	7.62-6	2,3,5,6	63	SA-1	6.15-6
		6	16		4.06-7
		5	52		9.10-7
AE	5.06-7	2,3	30		3.79-7
		No Power	62		1.20-7
ALFC	5.35-3	2,3,5,6	2	R-1	5.29-3
ALF	1.97-7	2,3,5,6	10	CS, R-1	1.91-7
ALC	1.68-7	5,6	4	CF-1, R-1	1.62-7
AL	1.23-11	2,3,6	12	CS, CF-1, R-1	6.36-12
		5,6	12	CS, CF-1, R-1	5.86-12

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1.3.6.3 Small LOCA--Event Tree 3 (ET-3) Quantification

The frequency of the small LOCA initiating event, ϕ_3, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_3) in Table 1.3.6.3-1. The other branch point split fraction data for the event tree (conditional on ϕ_3 and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.3-2.

When mean value data is propagated through the small LOCA event tree, the base case results displayed in Table 1.3.6.3-3 are obtained. Important plant split fractions that are dominated by complete or partial failure of electric power are corrected using the recovery of offsite power bounding technique described in Section 1.3.2. The split fractions SEFC, SEF, SEC, SE, SLFC, SLF, SLC, and SL have been corrected as shown in Table 1.3.6.3-3.

The plant split fractions in Table 1.3.4.6-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_3. The same table gives the split fractions, $M^{\beta}{}_3$, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.6.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.3-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.3-1

SMALL LOCA INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_3- Small LOCA (Annual Frequency)	1.03-4	1.11-2	5.43-2	2.01-2
AC Power Available at Buses (Given ϕ_3):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-2

ET-3 - SMALL LOCA

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-3	Small LOCA	-	-	-	1.0	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
HH-2	High Head Injection	3.2-5	9.7-5	3.4-4	1.4-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-1	Primary Cooling (Bleed and Feed)	1.7-3	3.7-3	1.0-2	4.4-3	1.3.3
CF-1	Fan Coolers	4.6-9	9.1-8	1.7-6	6.3-7	1.6.2
R-2	Recirculation Cooling	4.7-5	4.7-4	6.4-3	4.1-3	1.3.3
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2
RS	Recirculation Spray	5.5-5	5.5-4	5.5-3	1.5-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-2 (continued)

ET-3 - SMALL LOCA

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-3	Small LOCA	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
HH-2	High Head Injection	3.7-5	1.1-4	3.6-4	1.4-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-1	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
CF-1	Fan Coolers	1.3-3	2.5-3	4.8-3	2.8-3	1.6.2
R-2	Recirculation Cooling	6.9-4	3.0-3	1.3-2	8.4-3	1.3.3
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
RS	Recirculation Spray	4.0-4	2.0-3	7.0-3	3.0-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-2 (continued)

ET-3 - SMALL LOCA

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-3	Small LOCA	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
HH-2	High Head Injection	3.7-5	1.1-4	3.6-4	1.4-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
CF-1	Fan Coolers	6.0-7	2.1-6	9.7-6	3.9-6	1.6.2
R-2	Recirculation Cooling	6.9-4	3.0-3	1.3-2	8.4-3	1.3.3
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
RS	Recirculation Spray	4.0-4	2.0-3	7.0-3	3.0-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-2 (continued)

ET-3 - SMALL LOCA

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-3	Small LOCA	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
HH-2	High Head Injection	3.7-5	1.1-4	3.6-4	1.4-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Primary Cooling (Bleed and Feed)	1.7-3	3.7-3	1.0-2	4.4-3	1.3.3
CF-1	Fan Coolers	1.3-3	2.5-3	4.8-3	2.8-3	1.6.2
R-2	Recirculation Cooling	1.2-4	9.0-4	1.6-2	8.2-3	1.3.3
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2
RS	Recirculation Spray	5.5-5	5.5-4	5.5-3	1.5-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-2 (continued)

ET-3 - SMALL LOCA

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-3	Small LOCA	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
HH-2	High Head Injection	-	-	-	1.0	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Primary Cooling (Feed and Bleed)	-	-	-	1.0	1.3.3
CF-1	Fan Coolers	-	-	-	1.0	1.6.2
R-2	Recirculation Cooling	-	-	-	1.0	1.3.3
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2
RS	Recirculation Spray	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-2 (continued)

ET-3 - SMALL LOCA

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-3	Small LOCA	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
HH-2	High Head Injection	-	-	-	1.0	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Primary Cooling (Feed and Bleed)	-	-	-	1.0	1.3.3
CF-1	Fan Coolers	-	-	-	1.0	1.6.2
R-2	Recirculation Cooling	5.0-3	2.4-2	1.2-1	4.5-2	1.3.3
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
RS	Recirculation Spray	4.0-4	2.0-3	7.0-3	3.0-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-2 (continued)

ET-3 - SMALL LOCA

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-3	Small LOCA	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
HH-2	High Head Injection	-	-	-	1.0	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-1	Primary Cooling (Feed and Bleed)	-	-	-	1.0	1.3.3
CF-1	Fan Coolers	-	-	-	1.0	1.6.2
R-2	Recirculation Cooling	5.0-3	2.4-2	1.2-1	4.5-2	1.3.3
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2
RS	Recirculation Spray	4.0-4	2.0-3	7.0-3	3.0-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-2 (continued)

ET-3 - SMALL LOCA

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-3	Small LOCA	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
TK	Refuel Water Storage Tank	1.4-8	2.3-8	3.7-8	2.4-8	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
SA-1	SI Actuation Signal	2.3-7	2.4-6	2.5-5	6.2-6	1.3.3
HH-2	High Head Injection	-	-	-	1.0	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-1	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
CF-1	Fan Coolers	-	-	-	1.0	1.6.2
R-2	Recirculation Cooling	-	-	-	1.0	1.3.3
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2
RS	Recirculation Spray	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.3-3

INDIAN POINT 3 SMALL LOCA EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_3 = [	NOT MEANINGFUL																				]
M_3' = [	1.40-4	2.91-8	6.22-6	4.77-9	4.11-3	1.49-7	3.73-8	2.56-12	0	0	0	0	0	0	0	0	0	0	0	0	0]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None	
M_3' = [	3.90-5	5.07-10	5.07-10	5.85-8	1.50-11	1.66-11	3.74-11	4.57-12]	]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.3-4

ET-3 - SMALL LOCA EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SEFC	1.40-4	2,3,5,6	35	HH-2	1.40-4
SEF	2.91-8	2,3,5,6 2,3,5,6	45 37	TK HH-2, CS	2.40-8 5.04-9
SEC	6.22-6	2,3,5,6	41	SA-1	6.19-6
SE	4.77-9	2,3(3)[1] NP(3)[2]	40 40		3.40-9 1.10-9
SLFC	4.11-3	2,3,5,6	2	R-2	4.10-3
SLF	1.49-7	2,3,5,6	4	R-2, CS	1.48-7
SLC	3.73-8	2,3,5,6 5,6	6 6	CF-1, R-2 CF-1, R-2	2.58-9 3.44-8
SL	2.56-12	2,3,6 5,6	8 8	CF-1, R-2, CS CF-1, R-2, CS	1.22-12 1.24-12
ATWS	3.91-5	2,3,5,6	44	K-3	3.90-5

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1. Initially power at 2A and 3A, power not recovered in 3 hours.
2. Initially no power, power not recovered in 3 hours.

1.3.6.4 Steam Generator Tube Rupture--Event Tree 4 (ET-4) Quantification

The frequency of the steam generator tube rupture initiating event, ϕ_4, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_4) in Table 1.3.6.4-1. The other branch point split fraction data for the event tree (conditional on ϕ_4 and electric power state) are developed in Sections 1.3.3 and 1.6.2 and are summarized in Table 1.3.6.4-2. The data used to quantify the split fractions for event SL are summarized in Table 1.3.6.4-2A-1. The event tree for this event is presented in Section 1.3.4.4.4.

When mean value data are propagated through the steam generator tube rupture event tree, the base case results shown in Table 1.3.6.4-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power. The plant split fractions in Table 1.3.6.4-3 include contributions from the failure of reactor trip (ATWS).

Dominant sequences are listed in Table 1.3.6.4-4. Those that are dominant with respect to risk are discussed in Section 8 where risk is quantified.

TABLE 1.3.6.4-1

STEAM GENERATOR TUBE RUPTURE INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_4 - Steam Generator Tube Rupture (Annual Frequency)	4.20-5	8.61-3	9.83-2	3.37-2
AC Power Available at Buses (Given ϕ_4):				
2A, 3A, 5A, 6A	9.97-1	1.00+0	1.00+0	1.00+0
2A, 3A, 6A	3.43-7	4.99-6	5.87-5	1.31-5
2A, 3A, 5A	3.05-7	4.69-6	5.69-5	1.26-5
5A, 6A	6.09-4	1.20-3	2.90-3	1.48-3
2A, 3A	7.03-9	1.32-7	1.77-6	3.84-7
6A	4.06-8	1.97-7	1.79-6	4.41-7
5A	3.72-7	7.96-7	1.84-6	9.81-7
None	1.04-8	3.44-8	2.35-7	6.03-8

Note: Values are presented in an abbreviated scientific notation; e.g., 4.20-5 = 4.20×10^{-5}.

TABLE 1.3.6.4-2

ET-4 - STEAM GENERATOR TUBE RUPTURE

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	1.0	1.0	1.0	1.0	1.3.0
S	Reactor Trip and Safety Injection Signals	-	-	-	2.7-9	(1)
K-2	Reactor Trip	2.3-6	1.7-5	2.4-4	3.9-5	1.3.3
HH-*	High Head Injection	3.2-5	9.7-5	3.4-4	1.5-4	1.3.3
L-3	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-4*	Operator Controls Break Flow (a)	4.8-4	9.5-3	1.9-1	5.0-2	(2)
CF	Fan Coolers	1.8-6	1.4-5	1.1-4	3.2-5	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
SL	No Secondary Side Leakage to Atmosphere (b)	-	-	-	1.0-4	1.3.4
OP-5*	Depressurization and Makeup (c)	3.0-4	7.4-3	1.8-1	5.0-2	(2)
R-4	Long Term Cooling	5.0-6	2.1-4	1.4-3	5.3-4	(3)

1. See Reference 1.3-32.
2. See Reference 1.3-33.
3. See Reference 1.3-34.

a. $\overline{OP\text{-}41}$ = 5.0-2 given L-3;
$\overline{OP\text{-}42}$ = 7.0-2 given $\overline{L\text{-}3}$.

b. $\overline{SL}$ = 1.0-4 given OP-4;
$\overline{SL}$ = 5.2-3 given $\overline{OP\text{-}4}$.

c. $\overline{OP\text{-}50}$ = 1.0-6 given HH $\wedge$ L-3 $\wedge$ OP-4;
$\overline{OP\text{-}51}$ = 5.0-2 given HH $\wedge$ $\overline{L\text{-}3}$;
$\overline{OP\text{-}52}$ = 9.0-2 given HH $\wedge$ L-3 $\wedge$ SL;
$\overline{OP\text{-}53}$ = 1.0-3 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ $\overline{SL}$.

Note: Values are presented in an abbreviated scientific notation; e.g., 2.7-9 = 2.7×10^{-9}.

TABLE 1.3.6.4-2 (continued)

ET-4 - STEAM GENERATOR TUBE RUPTURE

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	3.4-7	5.0-6	5.9-5	1.3-5	1.3.0
S	Reactor Trip and Safety Injection Signals	-	-	-	2.7-9	(1)
K-2	Reactor Trip	2.3-6	1.7-5	2.4-4	3.9-5	1.3.3
HH-*	High Head Injection	3.7-5	1.1-4	3.6-4	1.5-4	1.3.3
L-3	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-4*	Operator Controls Break Flow (a)	4.8-4	9.5-3	1.9-1	5.0-2	(2)
CF	Fan Coolers	1.3-3	2.5-3	4.8-3	2.8-3	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
SL	No Secondary Side Leakage to Atmosphere (b)	-	-	-	3.9-4	1.3.4
OP-5*	Depressurization and Makeup (c)	-	-	-	1.0	(2)
R-4	Long Term Cooling	1.9-4	2.3-3	1.1-2	4.4-3	(3)

1. See Reference 1.3-32.
2. See Reference 1.3-33.
3. See Reference 1.3-34.

a. $\overline{OP\text{-}41}$ = 5.0-2 given $\underline{L\text{-}3}$;
   $\overline{OP\text{-}42}$ = 7.0-2 given $\overline{L\text{-}3}$.
b. $\overline{SL}$ = 3.9-4 given $\underline{OP\text{-}4}$;
   $\overline{SL}$ = 5.2-3 given $\overline{OP\text{-}4}$.
c. $\overline{OP\text{-}50}$ = 1.0-6 given HH $\wedge$ L-3 $\wedge$ OP-4;
   $\overline{OP\text{-}51}$ = 1.0 given HH $\wedge$ $\overline{L\text{-}3}$;
   $\overline{OP\text{-}52}$ = 9.0-2 given $\underline{HH}$ $\wedge$ L-3 $\wedge$ $\underline{SL}$;
   $\overline{OP\text{-}53}$ = 1.0-3 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ $\overline{SL}$.

Note: Values are presented in an abbreviated scientific notation; e.g., 3.4-7 = 3.4×10^{-7}.

TABLE 1.3.6.4-2 (continued)

ET-4 - STEAM GENERATOR TUBE RUPTURE

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	3.1-7	4.7-6	5.7-5	1.3-5	1.3.0
S	Reactor Trip and Safety Injection Signals	-	-	-	2.7-9	(1)
K-2	Reactor Trip	2.3-6	1.7-5	2.4-4	3.9-5	1.3.3
HH-*	High Head Injection	3.7-5	1.1-4	3.6-4	1.5-4	1.3.3
L-3	AFWS Actuation and Secondary Cooling	2.7-3	5.8-3	1.5-2	8.0-3	1.3.3
OP-4*	Operator Controls Break Flow (a)	4.8-4	9.5-3	1.9-1	5.0-2	(2)
CF	Fan Coolers	6.0-7	2.1-6	9.7-6	3.9-6	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
SL	No Secondary Side Leakage to Atmosphere (b)	-	-	-	3.9-4	1.3.4
OP-5*	Depressurization and Makeup (c)	-	-	-	1.0	(2)
R-4	Long Term Cooling	1.9-4	2.3-3	1.1-2	4.4-3	(3)

1. See Reference 1.3-32.
2. See Reference 1.3-33.
3. See Reference 1.3-34.

a. $\overline{OP\text{-}41}$ = 5.0-2 given $\underline{L\text{-}3}$;
$\overline{OP\text{-}42}$ = 7.0-2 given $\overline{L\text{-}3}$.
b. $\overline{SL}$ = 3.9-4 given $\underline{OP\text{-}4}$;
$\overline{SL}$ = 5.2-3 given $\overline{OP\text{-}4}$.
c. $\overline{OP\text{-}50}$ = 1.0-6 given HH $\wedge$ $\underline{L\text{-}3}$ $\wedge$ OP-4;
$\overline{OP\text{-}51}$ = 1.0 given HH $\wedge$ $\overline{L\text{-}3}$;
$\overline{OP\text{-}52}$ = 9.0-2 given $\underline{HH}$ $\wedge$ L-3 $\wedge$ $\underline{SL}$;
$\overline{OP\text{-}53}$ = 1.0-3 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ $\overline{SL}$.

Note: Values are presented in an abbreviated scientific notation; e.g., 3.1-7 = 3.1×10^{-7}.

TABLE 1.3.6.4-2 (continued)

ET-4 - STEAM GENERATOR TUBE RUPTURE

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	6.1-4	1.2-3	2.9-3	1.5-3	1.3.0
S	Reactor Trip and Safety Injection Signals	-	-	-	2.7-9	(1)
K-2	Reactor Trip	2.3-6	1.7-5	2.4-4	3.9-5	1.3.3
HH-*	High Head Injection	3.7-5	1.1-4	3.6-4	1.5-4	1.3.3
L-3	AFWS Actuation and Secondary Cooling	2.7-3	5.8-3	1.5-2	8.0-3	1.3.3
OP-4*	Operator Controls Break Flow (a)	4.8-4	9.5-3	1.9-1	5.0-2	(2)
CF	Fan Coolers	1.3-3	2.5-3	4.8-3	2.8-3	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
SL	No Secondary Side Leakage to Atmosphere (b)	-	-	-	3.9-4	1.3.4
OP-5*	Depressurization and Makeup (c)	3.0-4	7.4-3	1.8-1	5.0-2	(2)
R-4	Long Term Cooling	2.6-5	7.5-4	1.1-2	3.9-3	(3)

1. See Reference 1.3-32.
2. See Reference 1.3-33.
3. See Reference 1.3-34.

a. $\overline{OP\text{-}41}$ = 5.0-2 given L-3;
$\overline{OP\text{-}42}$ = 7.0-2 given $\overline{L\text{-}3}$.
b. $\overline{SL}$ = 3.9-4 given OP-4;
$\overline{SL}$ = 5.2-3 given $\overline{OP\text{-}4}$.
c. $\overline{OP\text{-}50}$ = 1.0-6 given HH $\wedge$ L-3 $\wedge$ OP-4;
$\overline{OP\text{-}51}$ = 5.0-2 given HH $\wedge$ $\overline{L\text{-}3}$;
$\overline{OP\text{-}52}$ = 9.0-2 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ $\overline{SL}$;
$\overline{OP\text{-}53}$ = 1.0-3 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ $\overline{SL}$.

Note: Values are presented in an abbreviated scientific notation; e.g., 6.1-4 = 6.1×10^{-4}.

TABLE 1.3.6.4-2 (continued)

ET-4 - STEAM GENERATOR TUBE RUPTURE

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	7.0-9	1.3-7	1.8-6	3.8-7	1.3.0
S	Reactor Trip and Safety Injection Signals	-	-	-	2.7-9	(1)
K-2	Reactor Trip	2.3-6	1.7-5	2.4-4	3.9-5	1.3.3
HH-*	High Head Injection	-	-	-	1.0	1.3.3
L-3	AFWS Actuation and Secondary Cooling	2.7-3	5.8-3	1.5-2	8.0-3	1.3.3
OP-4*	Operator Controls Break Flow (a)	4.8-4	9.5-3	1.9-1	5.0-2	(2)
CF	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
SL	No Secondary Side Leakage to Atmosphere (b)	-	-	-	3.9-4	1.3.4
OP-5*	Depressurization and Makeup (c)	-	-	-	1.0	(2)
R-4	Long Term Cooling	-	-	-	1.0	(3)

1. See Reference 1.3-32.
2. See Reference 1.3-33.
3. See Reference 1.3-34.

a. $\overline{OP\text{-}4I}$ = 5.0-2 given L-3;
   $\overline{OP\text{-}42}$ = 7.0-2 given $\overline{L\text{-}3}$.
b. $\overline{SL}$ = 3.9-4 given OP-4;
   $\overline{SL}$ = 5.2-3 given $\overline{OP\text{-}4}$.
c. $\overline{OP\text{-}50}$ = 1.0-6 given HH $\wedge$ L-3 $\wedge$ OP-4;
   $\overline{OP\text{-}5I}$ = 1.0 given HH $\wedge$ $\overline{L\text{-}3}$;
   $\overline{OP\text{-}52}$ = 9.0-2 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ SL;
   $\overline{OP\text{-}53}$ = 1.0-3 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ $\overline{SL}$.

Note: Values are presented in an abbreviated scientific notation; e.g., 7.0-9 = 7.0×10^{-9}.

TABLE 1.3.6.4-2 (continued)

ET-4 - STEAM GENERATOR TUBE RUPTURE

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	4.1-8	2.0-7	1.8-6	4.4-7	1.3.0
S	Reactor Trip and Safety Injection Signals	-	-	-	2.7-9	(1)
K-2	Reactor Trip	2.3-6	1.7-5	2.4-4	3.9-5	1.3.3
HH-*	High Head Injection	-	-	-	1.0	1.3.3
L-3	AFWS Actuation and Secondary Cooling	2.7-3	5.8-3	1.5-2	8.0-3	1.3.3
OP-4*	Operator Controls Break Flow (a)	4.8-4	9.5-3	1.9-1	5.0-2	(2)
CF	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
SL	No Secondary Side Leakage to Atmosphere (b)	-	-	-	3.9-4	1.3.4
OP-5*	Depressurization and Makeup (c)	-	-	-	1.0	(2)
R-4	Long Term Cooling	1.9-4	2.3-3	1.1-2	4.4-3	(3)

1. See Reference 1.3-32.
2. See Reference 1.3-33.
3. See Reference 1.3-34.

a. $\overline{OP\text{-}41}$ = 5.0-2 given L-3;
$\overline{OP\text{-}42}$ = 7.0-2 given $\overline{L\text{-}3}$.
b. $\overline{SL}$ = 3.9-4 given OP-4;
$\overline{SL}$ = 5.2-3 given $\overline{OP\text{-}4}$.
c. $\overline{OP\text{-}50}$ = 1.0-6 given HH $\wedge$ L-3 $\wedge$ OP-4;
$\overline{OP\text{-}51}$ = 1.0 given HH $\wedge$ $\overline{L\text{-}3}$;
$\overline{OP\text{-}52}$ = 9.0-2 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ SL;
$\overline{OP\text{-}53}$ = 1.0-3 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ $\overline{SL}$.

Note: Values are presented in an abbreviated scientific notation; e.g., 4.1-8 = 4.1×10^{-8}.

TABLE 1.3.6.4-2 (continued)

ET-4 - STEAM GENERATOR TUBE RUPTURE

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	3.7-7	8.0-7	1.8-6	9.8-7	1.3.0
S	Reactor Trip and Safety Injection Signals	-	-	-	2.7-9	(1)
K-2	Reactor Trip	2.3-6	1.7-5	2.4-4	3.9-5	1.3.3
HH-*	High Head Injection	-	-	-	1.0	1.3.3
L-3	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-4*	Operator Controls Break Flow (a)	4.8-4	9.5-3	1.9-1	5.0-2	(2)
CF	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
SL	No Secondary Side Leakage to Atmosphere (b)	-	-	-	3.9-4	1.3.4
OP-5*	Depressurization and Makeup (c)	-	-	-	1.0	(2)
R-4	Long Term Cooling	1.9-4	2.3-3	1.1-2	4.4-3	(3)

1. See Reference 1.3-32.
2. See Reference 1.3-33.
3. See Reference 1.3-34.

a. $\overline{OP\text{-}41}$ = 5.0-2 given L-3;
$\overline{OP\text{-}42}$ = 7.0-2 given $\overline{L\text{-}3}$.
b. $\overline{SL}$ = 3.9-4 given OP-4;
$\overline{SL}$ = 5.2-3 given $\overline{OP\text{-}4}$.
c. $\overline{OP\text{-}50}$ = 1.0-6 given HH $\wedge$ L-3 $\wedge$ OP-4;
$\overline{OP\text{-}51}$ = 1.0 given HH $\wedge$ $\overline{L\text{-}3}$;
$\overline{OP\text{-}52}$ = 9.0-2 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ SL;
$\overline{OP\text{-}53}$ = 1.0-3 given HH $\wedge$ L-3 $\wedge$ SL.

Note: Values are presented in an abbreviated scientific notation; e.g., 3.7-7 = 3.7×10^{-7}.

TABLE 1.3.6.4-2 (continued)

ET-4 - STEAM GENERATOR TUBE RUPTURE

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	1.0-8	3.4-8	2.4-7	6.0-8	1.3.0
S	Reactor Trip and Safety Injection Signals	-	-	-	2.7-9	(1)
K-2	Reactor Trip	1.8-8	8.9-7	2.2-5	9.2-6	1.3.3
HH-*	High Head Injection	-	-	-	1.0-3	1.3.3
L-3	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-4*	Operator Controls Break Flow (a)	4.8-4	9.5-3	1.9-1	5.0-2	(2)
CF	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
SL	No Secondary Side Leakage to Atmosphere (b)	-	-	-	3.9-4	1.3.4
OP-5*	Depressurization and Makeup (c)	-	-	-	1.0	(2)
R-4	Long Term Cooling	-	-	-	1.0	(3)

1. See Reference 1.3-32.
2. See Reference 1.3-33.
3. See Reference 1.3-34.

a. $\overline{OP\text{-}41}$ = 5.0-2 given L-3;
$\overline{OP\text{-}42}$ = 7.0-2 given $\overline{L\text{-}3}$.
b. $\overline{SL}$ = 3.9-4 given OP-4;
$\overline{SL}$ = 5.2-3 given $\overline{OP\text{-}4}$.
c. $\overline{OP\text{-}50}$ = 1.0-6 given HH $\wedge$ L-3 $\wedge$ OP-4;
$\overline{OP\text{-}51}$ = 1.0 given HH $\wedge$ $\overline{L\text{-}3}$;
$\overline{OP\text{-}52}$ = 9.0-2 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ SL;
$\overline{OP\text{-}53}$ = 1.0-3 given $\overline{HH}$ $\wedge$ L-3 $\wedge$ $\overline{SL}$.

Note: Values are presented in an abbreviated scientific notation; e.g., 1.0-8 = 1.0×10^{-8}.

TABLE 1.3.6.4-2A-1

SL - SECONDARY SIDE LEAKAGE TO ATMOSPHERE

AC Power Available at All Buses; OP = 0.0

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	-	-	-	1.0	-
SD	Steam Dump Available	-	-	-	1.0-4	(1)
OS	Operator Decides to Ioslate Steam Generator	-	-	-	1.0-4	(1)
IV	MSIV and Bypass Isolated	8.8-4	2.8-3	9.8-3	3.8-3	1.3.3
SG	Isolate Steaming Steam Generators	1.5-5	9.8-5	5.7-4	2.1-4	(1)
OP	Operator Controls Break Flow	-	-	-	0.0	-
MS	Main Steam Line Intact	-	-	-	1.0-4	(2)
AO	ARV Opens	1.9-4	8.6-4	3.8-3	1.5-3	1.3.3
AC	ARV Closes	6.7-3	2.0-2	6.0-2	2.5-2	(1)
AI	ARV Isolated	3.7-4	3.7-3	3.7-2	1.0-2	(1)
SN	SV Not Demanded	-	-	-	1.0-1	(3)
SO	SV Opens and Closes	3.8-4	3.2-3	3.3-2	9.3-3	(1)

1. See Reference 1.3-33.
2. See Reference 1.3-31.
3. Engineering judgment.

Note: Values are presented in an abbreviated scientific notation; e.g., 1.0-4 = 1.0×10^{-4}.

TABLE 1.3.6.4-2A-1 (continued)

SL - SECONDARY SIDE LEAKAGE TO ATMOSPHERE

AC Power Available at All Buses; OP = 1.0

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	-	-	-	1.0	-
SD	Steam Dump Available	-	-	-	1.0-4	(1)
OS	Operator Decides to Ioslate Steam Generator	-	-	-	1.0-4	(1)
IV	MSIV and Bypass Isolated	8.8-4	2.8-3	9.8-3	3.8-3	1.3.3
SG	Isolate Steaming Steam Generators	1.5-5	9.8-5	5.7-4	2.1-4	(1)
OP	Operator Controls Break Flow	-	-	-	1.0	-
MS	Main Steam Line Intact	-	-	-	1.0-4	(2)
AO	ARV Opens	1.9-4	8.6-4	3.8-3	1.5-3	1.3.3
AC	ARV Closes	6.7-3	2.0-2	6.0-2	2.5-2	(1)
AI	ARV Isolated	3.7-4	3.7-3	3.7-2	1.0-2	(1)
SN	SV Not Demanded	-	-	-	9.0-1	(3)
SO	SV Opens and Closes	1.2-2	1.3-1	7.1-1	2.0-1	(1)

1. See Reference 1.3-33.
2. See Reference 1.3-31.
3. Engineering judgment.

Note: Values are presented in an abbreviated scientific notation; e.g., 1.0-4 = 1.0×10^{-4}.

TABLE 1.3.6.4-2A-1 (continued)

SL - SECONDARY SIDE LEAKAGE TO ATMOSPHERE

Degraded Power State; OP = 0.0

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	-	-	-	1.0	-
SD	Steam Dump Available	-	-	-	1.0	(1)
OS	Operator Decides to Ioslate Steam Generator	-	-	-	1.0-4	(1)
IV	MSIV and Bypass Isolated	8.8-4	2.8-3	9.8-3	3.8-3	1.3.3
SG	Isolate Steaming Steam Generators	1.5-5	9.8-5	5.7-4	2.1-4	(1)
OP	Operator Controls Break Flow	-	-	-	0.0	-
MS	Main Steam Line Intact	-	-	-	1.0-4	(2)
AO	ARV Opens	1.9-4	8.6-4	3.8-3	1.5-3	1.3.3
AC	ARV Closes	6.7-3	2.0-2	6.0-2	2.5-2	(1)
AI	ARV Isolated	3.7-4	3.7-3	3.7-2	1.0-2	(1)
SN	SV Not Demanded	-	-	-	1.0-1	(3)
SO	SV Opens and Closes	3.8-4	3.2-3	3.3-2	9.3-3	(1)

1. See Reference 1.3-33.
2. See Reference 1.3-31.
3. Engineering judgment.

Note: Values are presented in an abbreviated scientific notation; e.g., 1.0-4 = 1.0×10^{-4}.

TABLE 1.3.6.4-2A-1 (continued)

SL - SECONDARY SIDE LEAKAGE TO ATMOSPHERE

Degraded Power State; OP = 1.0

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-4	Steam Generator Tube Rupture	-	-	-	1.0	-
SD	Steam Dump Available	-	-	-	1.0	(1)
OS	Operator Decides to Ioslate Steam Generator	-	-	-	1.0-4	(1)
IV	MSIV and Bypass Isolated	8.8-4	2.8-3	9.8-3	3.8-3	1.3.3
SG	Isolate Steaming Steam Generators	1.5-5	9.8-5	5.7-4	2.1-4	(1)
OP	Operator Controls Break Flow	-	-	-	1.0	-
MS	Main Steam Line Intact	-	-	-	1.0-4	(2)
AO	ARV Opens	1.9-4	8.6-4	3.8-3	1.5-3	1.3.3
AC	ARV Closes	2.7-3	2.0-2	6.0-2	2.5-2	(1)
AI	ARV Isolated	3.7-4	3.7-3	3.7-2	1.0-2	(1)
SN	SV Not Demanded	-	-	-	9.0-1	(3)
SO	SV Opens and Closes	1.2-2	1.3-1	7.1-1	2.0-1	(1)

1. See Reference 1.3-33.
2. See Reference 1.3-31.
3. Engineering judgment.

Note: Values are presented in an abbreviated scientific notation; e.g., 1.0-4 = 1.0×10^{-4}.

TABLE 1.3.6.4-3

INDIAN POINT 3 STEAM GENERATOR TUBE RUPTURE EVENT TREE QUANTIFICATION

1. Conditional Split Fractions[a]

	PLANT EVENT SEQUENCE CATEGORY[b]		
	V2E1	V2E2	V2L
M_4 =	9.07-10	7.14-10	1.61-6
M_4' =		Not Required	

2. Split Fractions to ATWS Conditional on Electric Power State

M_4^{β} = Not Required - ATWS Modeled in SGTR Event Tree

a. M = 6-hour electric power bounding model;
M' = results including electric power recovery.
b. Special plant event sequence categories which apply to SGTR are defined in Section 1.3.4.4.3.

Note: Values are presented in an abbreviated scientific notation; e.g., 9.07-10 = 9.07×10^{-10}.

TABLE 1.3.6.4-4

ET-4 - STEAM GENERATOR TUBE RUPTURE
EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
V2L	4.77-5	2,3,5,6	6	OP-4, R-4	2.64-5
		2,3,5,6	47	HH, OP-5	1.28-5
		2,3,5,6	11	L-3, OP-5	5.11-6
		2,3,5,6	2	OP-5	9.50-7
		2,3,5,6	53	HH, OP-4, OP-5	6.71-7
		2,3,5,6	29	L-3, OP-4, OP-5	3.83-7
		5,6	11	L-3, OP-5	5.56-7
		5,6	6	OP-4, R-4	2.88-7
V2E1	2.69-8	2,3,5,6	57	HH, L-3	1.65-8
		2,3,5,6	103	K-2, HH	5.85-9
		2,3,5,6	105	S	2.70-9
		5,6	57	HH, L-3	1.80-9
V2E2	2.12-8	5	17	L-3, CF, OP-5	1.45-8
		5	35	L-3, OP-4, CF, OP-5	1.09-9
		5,6	17	L-3, CF, OP-5	1.56-9
		6	17	L-3, CF, OP-5	3.26-9

Note: Values are presented in abbreviated scientific notation; e.g., 4.77-5 = 4.77×10^{-5}.

1.3.6.5 Steam Line Break Inside Containment--Event Tree 5 (ET-5) Quantification.

The frequency of the steam break inside containment initiating event, ϕ_5, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_5) in Table 1.3.6.5-1. The other branch point split fraction data for the event tree (conditional on ϕ_5 and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.5-2.

When mean value data is propagated through the steam line break inside containment event tree, the base case results shown in Table 1.3.6.5-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.6.5-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_5. The same table gives the split fractions, $M^{\beta}{}_5$, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.6.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.5-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.5-1

STEAM BREAK INSIDE CONTAINMENT INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_5 - Steam Break Inside Containment (Annual Frequency)	1.07-6	1.17-4	6.66-3	2.16-3
AC Power Available at Buses (Given ϕ_5):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-2

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-5	Steam Line Break Inside Containment	-	-	-	1.0	1.6.1
SA-2	SI Signal and High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-1	Feed and Bleed Cooling	1.7-3	3.7-3	1.0-2	4.4-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-2 (continued)

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-5	Steam Line Break Inside Containment	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
SA-2	SI Signal and High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-2 (continued)

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-5	Steam Line Break Inside Containment	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
SA-2	SI Signal and High Head Pumps	4.0-5	1.1-4	3.7-2	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-2 (continued)

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-5	Steam Line Break Inside Containment	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
SA-2	SI Signal and High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Feed and Bleed Cooling	1.7-3	3.7-3	1.0-2	4.4-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	8.1-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-2 (continued)

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-5	Steam Line Break Inside Containment	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
SA-2	SI Signal & High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-2 (continued)

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-5	Steam Line Break Inside Containment	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
SA-2	SI Signal & High Head Pumps	-	-	-	1.0	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-2 (continued)

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-5	Steam Line Break Inside Containment	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
SA-2	SI Signal & High Head Pumps	-	-	-	1.0	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-2 (continued)

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-5	Steam Line Break Inside Containment	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
SA-2	SI Signal and High Head Pumps	-	-	-	1.0	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.5-3

INDIAN POINT 3 STEAM LINE BREAK INSIDE CONTAINMENT EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

PLANT EVENT SEQUENCE CATEGORY[3]

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_5 = [	0	0	0	0	6.17-5	2.22-9	2.91-9	1.05-13	1.00-5	1.88-9	4.33-8	9.61-9	0	0	0	0	0	0	0	0	0]
M_5' = [	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M_5^B = [	3.90-5	5.07-10	5.07-10	5.85-8	1.48-11	1.68-11	3.74-11	1.10-12]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.5-4

ET-5 - STEAM LINE BREAK INSIDE CONTAINMENT EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	6.15-5	2,3,5,6	16	MS-1, R-3	6.12-5
SLF	2.21-9	2,3,5,6	18	MS-1, R-3, CS	2.20-9
SLC	2.90-9	2,3,5,6	19	MS-1, R-3, CF-2	1.59-10
		5,6	19	MS-1, R-3, CF-2	2.72-9
SL	1.04-13	2,3,5,6	21	MS-1, R-3, CF-2, CS	5.73-15
		5,6	21	MS-1, R-3, CF-2, CS	9.80-14
TEFC	6.88-5	2,3,5,6	22	MS-1, OP-1	6.59-5
		2,3,5,6	36	SA-2, MS-1	2.25-6
TEF	4.00-9	2,3,5,6	24	MS-1, OP-1, CS	2.38-9
		2,3,5,6	38	SA-2, MS-1, CS	8.10-11
		2,3,6	24	MS-1, CS	7.51-10
		2,3,5	24	MS-1, CS	7.80-10
TEC	4.48-8	2,3,6	25	MS-1, CF-2	7.18-9
		5,6	25	MS-1, OP-1, CF-2	1.48-9
		6	39	MS-1	6.42-9
		5	33	L-1	1.50-8
		5	39	MS-1	1.43-8
TE	9.61-9	2,3	27	MS-1	5.70-9
		No Power	35	L-1	1.89-9
		No Power	41	MS-1	1.80-9
ATWS	3.91-5	2,3,5,6	28	K-3	3.90-5

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1.3.6.6 Steam Line Break Outside Containment--Event Tree 6 (ET-6) Quantification

The frequency of the steam break outside containment initiating event, ϕ_6, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_6) in Table 1.3.6.6-1. The other branch point split fraction data for the event tree (conditional on ϕ_6 and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.6-2.

When mean value data is propagated through the steam line break outside containment event tree, the base case results shown in Table 1.3.4.6-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.6.6-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_6. The same table gives the split fractions, M^{β}_6, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.6.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.6-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.6-1

STEAM LINE BREAK (OUTSIDE) CONTAINMENT
INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_6 - Steam Line Break (Outside) Containment (Annual Frequency)	1.07-6	1.17-4	6.66-3	2.16-3
AC Power Available at Buses (Given ϕ_6):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-2

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	-	-	-	1.0	1.6.1
SA-2	SI Signal and High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-1	Feed and Bleed Cooling	1.7-3	3.7-3	1.0-2	4.4-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
SA-2	SI Signal and High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
SA-2	SI Signal and High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
SA-2	SI Signal and High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Feed and Bleed Cooling	1.7-3	3.7-3	1.0-2	4.4-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	8.1-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
SA-2	SI Signal & High Head Pumps	4.0-5	1.1-4	3.7-4	1.5-4	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
SA-2	SI Signal & High Head Pumps	-	-	-	1.0	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
SA-2	SI Signal & High Head Pumps	-	-	-	1.0	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-2 (continued)

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-6	Steam Line Break Outside Containment	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
SA-2	SI Signal and High Head Pumps	-	-	-	1.0	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-1	Feed and Bleed Cooling	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.6-3

INDIAN POINT 3 STEAM LINE BREAK OUTSIDE CONTAINMENT EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_6 = [	0	0	0	0	6.17-5	2.22-9	2.91-9	1.05-13	1.00-5	1.88-9	4.33-8	9.61-9	0	0	0	0	0	0	0	0	0]
M'_6 = [	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^E_6 = [	3.9-05	5.07-10	5.07-10	5.85-8	1.48-11	1.68-11	3.74-11	1.10-12]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.6-4

ET-6 - STEAM LINE BREAK OUTSIDE CONTAINMENT EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. __A	Seq.		
SLFC	6.15-5	2,3,5,6	16	MS-1, R-3	6.12-5
SLF	2.21-9	2,3,5,6	18	MS-1, R-3, CS	2.20-9
SLC	2.90-9	2,3,5,6	19	MS-1, R-3, CF-2	1.59-10
		5,6	19	MS-1, R-3, CF-2	2.72-9
SL	1.04-13	2,3,5,6	21	MS-1, R-3, CF-2, CS	5.73-15
		5,6	21	MS-1, R-3, CF-2, CS	9.80-14
TEFC	6.88-5	2,3,5,6	22	MS-1, OP-1	6.59-5
		2,3,5,6	36	SA-2, MS-1	2.25-6
TEF	4.00-9	2,3,5,6	24	MS-1, OP-1, CS	2.38-9
		2,3,5,6	38	SA-2, MS-1, CS	8.10-11
		2,3,6	24	MS-1, CS	7.51-10
		2,3,5	24	MS-1, CS	7.80-10
TEC	4.48-8	2,3,6	25	MS-1, CF-2	7.18-9
		5,6	25	MS-1, OP-2, CF-2	1.48-9
		6	39	MS-1	6.42-9
		5	33	L-1	1.50-8
		5	39	MS-1	1.43-8
TE	9.61-9	2,3	27	MS-1	5.70-9
		No Power	35	L-1	1.89-9
		No Power		MS-1	1.80-9
ATWS	3.91-5	2,3,5,6	28	K-3	3.90-5

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1.3.6.7 Loss of Main Feedwater--Event Tree 7 (ET-7) Quantification

The frequency of the loss of main feedwater initiating event, ϕ_7, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_7) in Table 1.3.4.7-1. The other branch point split fraction data for the event tree (conditional on ϕ_7 and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.7-2.

When mean value data is propagated through the loss of main feedwater event tree, the base case results shown in Table 1.3.6.7-3 are obtained. Important plant split fractions that are dominated by complete or partial failure of electric power are corrected using the recovery of offsite power bounding technique described in Section 1.3.2. The split fractions to SLFC, SLF, SLC, SL, TEFC, TEF, TEC, and TE have been corrected as shown in Table 1.3.6.7-3.

The plant split fractions in Table 1.3.6.7-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_7. The same table gives the split fractions, M^{β}_7, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.4.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.7-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.7-1

LOSS OF MAIN FEEDWATER FLOW INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_7 - Loss of Main Feedwater Flow (Annual Frequency)	2.18+0	3.55+0	5.48+0	3.80+0
AC Power Available at Buses (Given ϕ_7):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-2

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	-	-	-	1.0	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.7-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.7-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	8.1-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-2 (continued)

ET-7 - LOSS OF FEEDWATER FLOW

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-7	Loss of Feedwater Flow	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.7-3

INDIAN POINT 3 LOSS OF MAIN FEEDWATER FLOW EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_7 = [	NOT MEANINGFUL																				]
M_7' = [	0	0	0	0	6.30-8	2.27-12	2.02-11	7.27-16	9.97-9	6.78-12	1.46-10	1.86-10	0	0	0	0	0	0	0	0	0]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None	
M_7^B = [	[3.90-5	5.07-10	5.07-10	5.85-8	1.50-11	1.66-11	3.74-11	4.57-12	]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.7-4

ET-7 - LOSS OF MAIN FEEDWATER EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	6.28-8	2,3,5,6	3	L-1, R-3	6.12-8
		5,6	3	L-1, R-3	1.31-9
SLF	2.26-12	2,3,5,6	5	L-1, R-3, CS	2.20-12
SLC	2.01-11	5,6	6	L-1, R-3, CF-2	1.99-11
SL	7.24-16	5,6	8	L-1, R-3, CF-2, CS	7.18-16
TEFC	7.09-8	2,3,5,6	9	L-1, OP-2	6.74-9
		2,3,5	9	L-1	1.42-9
		5(2)[1]	9	L-1	7.99-11
TEF	8.97-12	2,3,5,6	11	L-1, OP-2, CS	2.43-12
		2,3,6	11	L-1, CS	7.51-13
		2,3,5	11	L-1, CS	5.72-12
TEC	1.56-10	2,3,6	12	L-1, CF-2	7.18-12
		5,6	12	L-1, OP-2, CF-2	1.11-11
		5(3)[2]	12	L-1	1.37-10
TE	1.86-11	5(3)[2]	14	L-1, CS	5.50-13
		NP(3)[3]	14	L-1	1.76-11
ATWS	3.91-5	2,3,5,6	42	K-3	3.90-5

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1. Initially power at 5A, power recovered in 3 hours.
2. Initially power at 5A, power not recovered.
3. Initially no power, power not recovered.

1.3.6.8 Closure of One Main Steam Isolation Valve--Event Tree 8 (ET-8) Quantification

The frequency of the trip of one MSIV initiating event, ϕ_8, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_8) in Table 1.3.6.8-1. The other branch point split fraction data for the event tree (conditional on ϕ_8 and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.8-2.

When mean value data is propagated through the trip of one MSIV event tree, the base case results shown in Table 1.3.6.8-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

Dominant sequences are listed in Table 1.3.6.8-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.8-1

CLOSURE OF ONE MSIV INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_8 - Trip of One MSIV (Annual Frequency)	1.09-3	3.81-2	2.96-1	8.98-2
AC Power Available at Buses (Given ϕ_8):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-2

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	-	-	-	1.0	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.7-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	8.1-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-2 (continued)

ET-8 - CLOSURE OF ONE MSIV

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-8	Closure of One MSIV	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
OP-3	Operator Stabilizes Transient	-	-	-	0.0	1.3.3
TT-1	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip (Manual)	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.8-3

INDIAN POINT 3 CLOSURE OF ONE MSIV EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

PLANT EVENT SEQUENCE CATEGORY[3]

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_8 =[	0	0	0	0	6.30-8	2.27-12	2.02-11	7.27-16	9.06-9	6.74-12	1.54-8	2.02-9	0	0	0	0	0	0	0	0	0]
M'_8 =[	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M_8^{β} =[	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.1-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.8-4

ET-8 - CLOSURE OF ONE MSIV EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	6.27-8	2,3,5,6 5,6	3 3	L-1, R-3 L-1, R-3	6.12-8 1.31-9
SLF	2.26-12	2,3,5,6	5	L-1, R-3, CS	2.20-12
SLC	2.01-11	5,6	6	L-1, R-3, CF-2	1.99-11
SL	7.24-16	5,6	8	L-1, R-3, CF-2, CS	7.18-16
TEFC	7.00-8	2,3,5,6 2,3,5	9 9	L-1, OP-2 L-1,	6.74-8 1.42-9
TEF	8.94-12	2,3,5,6 2,3,6 2,3,5	11 11 11	L-1, OP-2, CS L-1, CS L-1, CS	2.43-12 7.51-13 5.72-12
TEC	1.54-8	5	12	L-1,	1.53-8
TE	2.02-9	5 No Power	14 14	L-1, CS L-1,	6.14-11 1.92-9

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1.3.6.9 Loss of Reactor Coolant System Flow--Event Tree 9 (ET-9) Quantification

The frequency of the loss of reactor coolant system flow initiating event, ϕ_9, is developed in Section 1.5.1 and is shown with the electric power state split fraction data (conditional on ϕ_9) in Table 1.3.6.9-1. The other branch point split fraction data for the event tree (conditional on ϕ_9 and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.9-2.

When mean value data is propagated through the loss of RCS flow event tree, the base case results shown in Table 1.3.6.9-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.6.9-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_9. The same table gives the split fractions, $M^{\beta}{}_9$, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.4.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.9-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.9-1

LOSS OF PRIMARY FLOW INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_9 - Loss of Primary Flow (Annual Frequency)	1.38-2	1.19-1	4.24-1	1.71-1
AC Power Available at Buses (Given ϕ_9):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-2

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	-	-	-	1.0	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.7-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.1-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.7-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	8.1-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation & Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation & Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation & Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.6.2
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-2 (continued)

ET-9 - LOSS OF RCS FLOW

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-9	Loss of RCS Flow	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.9-3

INDIAN POINT 3 LOSS OF PRIMARY FLOW EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

PLANT EVENT SEQUENCE CATEGORY[3]

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_9 = [	0	0	0	0	5.67-8	2.04-12	1.82-11	6.55-16	8.16-9	6.07-12	1.38-8	1.82-9	0	0	0	0	0	0	0	0	0]
M'_9 = [										NOT REQUIRED											]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None	
M_9^B = [	3.51-5	4.56-10	4.56-10	5.27-8	1.33-11	1.51-11	3.37-11	9.94-13	]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.9-4

ET-9 - LOSS OF PRIMARY FLOW EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	5.67-8	2,3,5,6 5,6	3 3	L-1, R-3 L-1, R-3	5.53-8 1.18-9
SLF	2.04-12	2,3,5,6	5	L-1, R-3, CS	1.99-12
SLC	1.82-11	5,6	6	L-1, R-3, CF-2	1.80-11
SL	6.55-16	5,6	8	L-1, R-3, CF-2,	6.49-16
TEFC	8.16-9	2,3,5,6 2,3,5	9 9	L-1, OP-2 L-1	6.61-9 1.28-9
TEF	6.07-12	2,3,5,6 2,3,6 2,3,5	11 11 11	L-1, OP-2, CS L-1, CS L-1, CS	2.38-13 6.76-13 5.15-12
TEC	1.38-8	5	12	L-1	1.38-8
TE	1.82-9	5 No Power	14 14	L-1, CS L-1	5.53-11 1.73-9
ATWS	3.52-5	2,3,5,6	42	K-3	3.51-5

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1.3.6.10 Core Power Excursion--Event Tree 10 (ET-10) Quantification

The frequency of the core power excursion initiating event, ϕ_{10}, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_{10}) in Table 1.3.6.10-1. The other branch point split fraction data for the event tree (conditional on ϕ_{10} and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.10-2.

When mean value data is propagated through the core power excursion event tree, the base case results shown in Table 1.3.6.10-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.6.10-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_{10}. The same table gives the split fractions, M^{β}_{10}, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.6.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.10-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.10-1

CORE POWER EXCURSION INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{10} - Core Power Excursion (Annual Frequency)	4.40-5	1.02-2	8.18-2	2.57-2
AC Power Available at Buses (Given ϕ_{10}):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-2

ET-10 - CORE POWER EXCURSION

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	-	-	-	1.0	1.6.1
OP-4	Operator Terminates Excursion	3.3-6	6.6-5	1.3-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.6-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.7-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
OP-3	Operator Terminates Excursion	3.3-6	6.6-5	1.3-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.6-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
OP-3	Operator Terminates Excursion	3.3-6	6.6-5	1.3-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
OP-3	Operator Terminates Excursion	3.3-6	6.6-5	1.3-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.7-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	6.9-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
OP-3	Operator Terminates Excursion	3.3-6	6.6-5	1.3-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
OP-3	Operator Terminates Excursion	3.3-6	6.6-5	1.3-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-2 (continued)

ET-10 - CORE POWER EXCURSION

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
OP-3	Operator Terminates Excursion	3.3-6	6.6-5	1.3-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-2 (continued)

ET-10 - CORE POWER EXCURSION

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-10	Core Power Excursion	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
OP-3	Operator Terminates Excursion	3.3-6	6.6-5	1.3-3	3.5-4	1.3.3
K-5	Power Runback	-	-	-	1.0-3	1.3.3
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.10-3

INDIAN POINT 3 CORE POWER EXCURSION EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{10} = [	0	0	0	0	2.20-14	7.91-19	7.07-18	2.54-22	3.16-15	2.36-18	5.37-15	7.08-16	0	0	0	0	0	0	0	0	0]
M'_{10} = [	NOT REQUIRED																				]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{B}_{10} = [	1.37-11	1.77-16	1.77-16	2.05-14	5.19-18	5.87-18	1.31-17	3.86-19]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.10-4

ET-10 - CORE POWER EXCURSION EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	2.19-14	2,3,5,6	5	OP-3, K-5, L-1, R-3	2.14-14
SLF	7.88-19	2,3,5,6	7	OP-3, K-5, L-1, R-3, CS	7.71-19
SLC	7.04-18	5,6	8	OP-3, K-5, L-1, R-3, CF-2	6.98-18
SL	2.53-22	5,6	10	OP-3, K-5, L-1, R-3, CF-2, CS	2.51-22
TEFC	2.44-14	2,3,5,6	11	OP-3, K-5, L-1, OP-2	2.36-14
		2,3,5	11	OP-3, K-5, L-1	4.98-16
TEF	3.12-18	2,3,5,6	13	OP-3, K-5, L-1, OP-2, CS	8.50-19
		2,3,6	13	OP-3, K-5, L-1, CS	2.63-19
		2,3,5	13	OP-3, K-5, L-1, CS	2.00-18
TEC	5.37-15	5	14	OP-3, K-5, L-1	5.35-15
TE	7.08-16	5	16	OP-3, K-5, L-1	2.15-17
		No Power	16	OP-3, K-5, L-1	6.72-16
ATWS	1.37-11	2,3,5,6	17	OP-3, K-5, K-3	

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1.3.6.11 Turbine Trip--Event Tree 11 (ET-11) Quantification

1.3.6.11.1 Turbine Trip Base Case Quantification

The frequency of the turbine trip (general) initiating event, ϕ_{11a}, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_{11a}) in Table 1.3.6.11a-1. The other branch point split fraction data for the event tree (conditional on ϕ_{11a} and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.11a-2.

When mean value data is propagated through the turbine trip (general) event tree (ET-11a), the base case results shown in Table 1.3.6.11a-3 are obtained. Important plant split fractions that is dominated by complete or partial failure of electric power are corrected using the recovery of the offsite power bounding technique described in Section 1.3.3. The split fractions for SLFC, SLF, SLC, SL, TEFC, TEF, TEC, and TE have been corrected as shown in Table 1.3.6.11a-3.

The plant split fractions in Table 1.3.6.11a-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_{11a}. The same table gives the split fractions, M^{β}_{11a}, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.4.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.11a-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

1.3.6.11.2 Turbine Trip--Loss of Offsite Power Quantification

The frequency of the turbine trip--loss of offsite power initiating event, ϕ_{11b}, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_{11b}) in Table 1.3.6.11b-1. The other branch point split fraction data for the event tree (conditional on ϕ_{11b} and electric power state) is developed in Sections 1.3.2, 1.3.3, and 1.6.2 and is summarized in Table 1.3.6.11b-2. Many degraded states of electric power appear to be important for this event tree because it is initiated by a loss of offsite power. Therefore, the entire tree has been revised to account for recovery of electric power as described in Section 1.3.2.2.

The plant split fractions in Table 1.3.6.11b-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_{11b}. The same table gives the split fractions, M^{β}_{11b}, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.6.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.11b-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

1.3.6.11.3 Turbine Trip--Loss of Service Water Quantification

The frequency of the turbine trip--loss of service water initiating event, ϕ_{11c}, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_{11c}) in Table 1.3.6.11c-1. The other branch point split fraction data for the event tree (conditional on ϕ_{11c} and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.11c-2.

When mean value data is propagated through the turbine trip--loss of service water event tree, the base case results shown in Table 1.3.6.11c-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

The plant split fractions in Table 1.3.6.11c-3 do not include contributions from the failure of reactor trip (ATWS) event tree. These conditional split fractions without the ATWS contribution are labeled M_{11c}. The same table gives the split fractions, M^{β}_{11c}, going to the ATWS event tree (ET-13) conditional on electric power state. Later, in Section 1.3.6.13, the conditional plant matrix from ATWS, M(ATWS), is calculated. M(ATWS) and all the M_i's are combined into the complete plant matrix, M, in Section 1.4.

Dominant sequences are listed in Table 1.3.6.11c-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

TABLE 1.3.6.11a-1

TURBINE TRIP INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{11a} - Turbine Trip (Annual Frequency)	1.33+0	2.50+0	4.08+0	2.72+0
AC Power Available at Buses (Given ϕ_{11a}):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-2

ET-11a - TURBINE TRIP

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	-	-	-	1.0	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.7-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.7-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	8.1-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-2 (continued)

ET-11a - TURBINE TRIP

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-2 (continued)

ET-11a - TURBINE TRIP

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11a	Turbine Trip	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11a-3

INDIAN POINT 3 TURBINE TRIP EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{11A} = [	NOT MEANINGFUL																	0	0	0	0]
M'_{11A} = [	0	0	0	0	6.28-8	2.26-12	2.02-11	7.27-16	9.95-9	6.77-12	1.46-10	1.86-11	0	0	0	0	0	0	0	0	0]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{8}_{11A} = [	3.90-5	5.07-10	5.07-10	5.85-8	1.50-11	1.66-11	3.74-11	4.57-12]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.6.11a-4

ET-11a - TURBINE TRIP EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	6.26-8	2,3,5,6	3	L-1, R-3	6.12-8
		5,6	3	L-1, R-3	1.31-9
SLF	2.25-12	2,3,5,6	5	L-1, R-3, CS	2.20-12
SLC	2.01-11	5,6	6	L-1, R-3, CF-2	1.99-11
SL	7.24-16	5,6	8	L-1, R-3, CF-2, CS	7.18-16
TEFC	7.07-8	2,3,5,6	9	L-1, OP-2	6.74-8
		2,3,5	9	L-1	1.42-9
		5,6	9	L-1, OP-2	7.31-10
TEF	8.96-12	2,3,5,6	11	L-1, OP-2, CS	2.43-12
		2,3,6	11	L-1, CS	7.51-13
		2,3,5	11	L-1, CS	5.72-12
TEC	1.56-10	2,3,6	12	L-1, CF-2	7.18-12
		5,6	12	L-1, OP-2, CF-2	1.11-11
		5(3)[1]	12	L-1	1.37-10
TE	1.86-11	5(3)[1]	14	L-1, CS	5.50-13
		NP(3)[2]	14	L-1	1.76-11
ATWS	3.91-5	2,3,5,6	15	K-3	3.90-5

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1. Initially power at 5A, power not recovered in 3 hours.
2. Initially no power, power not recovered in 3 hours.

TABLE 1.3.6.11b-1

TURBINE TRIP (LOSS OF OFFSITE POWER)
INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{11b} - Turbine Trip (Loss of Offsite Power) (Annual Frequency)	3.66-2	1.95-1	5.78-1	2.66-1
AC Power Available at Buses (Given ϕ_{11b}):				
2A, 3A, 5A, 6A	8.63-1	8.96-1	9.35-1	8.99-1
2A, 3A, 6A	1.85-2	2.96-2	4.37-2	3.16-2
2A, 3A, 5A	1.85-2	2.96-2	4.37-2	3.16-2
5A, 6A	1.85-2	2.96-2	4.37-2	3.16-2
2A, 3A	5.14-2	9.81-4	1.67-3	1.09-3
6A	5.14-2	9.81-4	1.67-3	1.09-3
5A	5.14-2	9.81-4	1.67-3	1.09-3
None	6.19-4	9.61-4	1.47-3	1.01-3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-2

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	8.6-1	9.0-1	9.4-1	9.0-1	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
LS	RCP Seal LOCA	-	-	-	3.0-7	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.7-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.5-9	2.1-7	1.2-5	4.0-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	1.9-2	3.0-2	4.4-2	3.2-2	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
LS	RCP Seal LOCA	-	-	-	3.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.2-4	2.7-3	1.6-2	7.0-3	1.3.3
CF-2	Fan Coolers	4.0-4	1.5-2	3.4-1	8.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	1.9-2	3.0-2	4.4-2	3.2-2	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
LS	RCP Seal LOCA	-	-	-	3.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.2-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	1.6-2	7.0-3	1.3.3
CF-2	Fan Coolers	1.0-7	1.4-5	9.6-4	2.8-4	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	1.9-2	3.0-2	4.4-2	3.2-2	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
LS	RCP Seal LOCA	-	-	-	3.0-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.7-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.5-3	2.1-2	8.2-3	1.3.3
CF-2	Fan Coolers	1.8-4	7.9-3	1.8-1	4.6-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	5.1-5	9.8-4	1.7-3	1.1-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
LS	RCP Seal LOCA	-	-	-	1.5-3	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	5.1-5	9.8-4	1.7-3	1.1-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
LS	RCP Seal LOCA	-	-	-	1.5-3	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	5.1-5	9.8-4	1.7-3	1.1-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
LS	RCP Seal LOCA	-	-	-	1.5-3	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-2 (continued)

ET-11b - TURBINE TRIP, LOSS OF OFFSITE POWER

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11b	Turbine Trip, Loss of Offsite Power	6.2-4	9.6-4	1.5-3	1.0-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
LS	RCP Seal LOCA	-	-	-	1.0	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-3

INDIAN POINT 3 TURBINE TRIP, LOSS OF OFFSITE POWER EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

		PLANT EVENT SEQUENCE CATEGORY[3]																				
		SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M	=	[									NOT MEANINGFUL											]
m'	=	[1.01-5	3.68-10	2.25-8	2.36-6	4.22-7	3.38-11	2.34-11	2.70-14	8.75-7	1.47-10	7.42-8	8.04-10	0	0	0	0	0	0	0	0	0

2. Split Fractions to ATWS Conditional on Electric Power State

		ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and Power Recovered	ATWS and None	
M_{11}^{β}	=	[2.66-6	2.39-7	2.39-7	2.39-7	6.44-9	6.44-9	6.44-9	1.82-9	1.66-11	]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.11b-4

ET-11b(R) - TURBINE TRIP, LOSS OF OFFSITE POWER
EVENT TREE DOMINANT SEQUENCES
(With Recovery)

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Initially Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SEFC	1.01-5	NP	41*	HH-2	9.99-6
SEF	3.68-10	NP	41	HH-2, CS	3.60-10
SEC	2.25-8	6	41	HH-2, CF-1	1.09-8
		5	41	HH-2, CF-1	1.09-8
SE	2.36-6	2,3	41	HH-2, CF-1, CS	5.60-7
		NP	41	HH-2, CF-1, CS	1.80-6
SLFC	4.21-7	NP	41	R-2	3.14-7
		2,3,5,6	3	L-1, R-3	5.95-8
		5	3	L-1, R-3	2.12-8
SLF	3.38-11	NP	41	R-2, CS	1.13-11
		2,3,6	41	R-2, CS	9.38-12
		2,3,5	41	R-2, CS	9.14-12
		2,3,5,6	5	L-1, R-2	2.14-12
SLC	1.02-11	2,3,6	41	CF-1, R-2	6.55-12
		5,6	41	CF-1, R-2	6.42-12
		5,6	26	L-1, EP-2, EP-3, R-3, CF-2	9.75-12

*Sequence 41 is a small LOCA due to reactor coolant pump seal failure. The sequence branches to the small LOCA Event Tree (ET-3) where it is quantified conditional on successful reactor trip and AC power availability. Electric power recovery is modeled there.

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11b-4 (continued)

ET-11b(R) - TURBINE TRIP, LOSS OF OFFSITE POWER
EVENT TREE DOMINANT SEQUENCES
(With Recovery)

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Initially Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SL	2.70-14	2,3,6	41	CF-1, R-2, CS	2.63-14
TEFC	9.63-7	2,3,5,6	9	L-1, OP-2	6.56-8
		2,3,6	29	L-1, EP-2	1.63-8
		2,3,5	29	L-1, EP-2	1.20-7
		2,3,5	35	L-1, EP-2, EP-3	2.58-8
		5	29	L-1, EP-2	6.89-7
		5	9	L-1	2.34-8
TEF	1.50-10	2,3,6	37	L-1, EP-2, EP-3, CS	1.29-11
		2,3,5	37	L-1, EP-2, EP-3, CS	1.04-10
		5	31	L-1, EP-2, CS	2.48-11
TEC	7.42-8	5	38	L-1, EP-2, EP-3	7.32-8
TE	8.04-10	2,3	40	L-1, EP-2, EP-3	5.06-10
		5	40	L-1, EP-2, EP-3	2.95-10
ATWS	3.40-6	2,3,5,6	42	K-3	2.66-6
		2,3,6	42	K-3	2.39-7
		2,3,5	42	K-3	2.39-7
		5,6	42	K-3	2.39-7

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11c-1

TURBINE TRIP (LOSS OF SERVICE WATER)
INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{11c} - Turbine Trip (Loss of Service Water) (Annual Frequency)	1.07-6	1.17-4	6.66-3	2.16-3
AC Power Available at Buses (Given ϕ_{11c}):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
None	5.10-4	1.28-3	2.87-3	1.51-3

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11c-2

ET-11c - TURBINE TRIP, LOSS OF SERVICE WATER

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11c	Turbine Trip, Loss of Service Water	-	-	-	1.0	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.7-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11c-2 (continued)

ET-11c - TURBINE TRIP, LOSS OF SERVICE WATER

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-11c	Turbine Trip, Loss of Service Water	5.1-4	1.3-3	2.9-3	1.5-3	1.6.1
K-3	Reactor Trip	6.0-7	6.5-6	1.7-4	3.9-5	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.11c-3

INDIAN POINT 3 TURBINE TRIP, LOSS OF SERVICE WATER EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

PLANT EVENT SEQUENCE CATEGORY[3]

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{11C} = [	0	0	0	0	0	0	1.49-5	5.38-10	0	0	6.74-8	2.40-5	0	0	0	0	0	0	0	0	0]
M'_{11C} = [									NOT REQUIRED												]

2. Split Fractions to ATWS Conditional on Electric Power State

	ATWS and 2A,3A,5A,6A	ATWS and None
M^{B}_{11C} = [	3.90-5	1.38-8]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior
   S - Small LOCA behavior
   T - Transient behavior
   E - Early melt
   L - Late melt
   F - Fan coolers are operating
   C - Containment sprays are operating

TABLE 1.3.6.11c-4

ET-11c - TURBINE TRIP, LOSS OF SERVICE WATER
EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. __A	Seq.		
SLC	1.49-5	2,3,5,6	6	L-1	1.49-5
SL	5.38-10	2,3,5,6	8	L-1, OP-2	5.38-5
TEC	6.75-8	2,3,5,6	12	L-1, OP-2	6.74-8
TE	2.40-5	No Power	14	L-1	2.40-5
ATWS	3.90-5	2,3,5,6	15	K-3	3.90-5

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1.3.6.12 Reactor Trip--Event Tree 12 (ET-12) Quantification

1.3.6.12.1 Reactor Trip Quantification

The frequency of the reactor trip initiating event, ϕ_{12a}, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional on ϕ_{12a}) in Table 1.3.6.12a-1. The other branch point split fraction data for the event tree (conditional on ϕ_{12a} and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.12a-2.

When mean value data are propagated through the reactor trip event tree, the base case results shown in Table 1.3.6.12a-3 are obtained. Important plant split fractions that are dominated by complete or partial failure of electric power are quantified using the recovery of offsite power bounding technique described in Section 1.3.2. The split fractions for TEFC, TEF, and TE have been quantified using this technique, and the results are shown in Table 1.3.6.12a-3.

Dominant sequences are listed in Table 1.3.6.12a-4. Those that are dominant with respect to risk are discussed in Section 8 where risk is quantified. The frequencies of those sequences are requantified there to properly account for uncertainty.

1.3.6.12.2 Special Initiating Events That Fail Mitigating Systems by Common Cause

The plant event trees are modeled under the conditions that all DC and ESF AC buses, component cooling water, and service water are available just before the initiating event. Loss of any of these systems leads to a reactor trip or shutdown. Loss of service water has been examined using the turbine trip event tree in Section 1.3.4.11. In this section, the effects of the other support system failures on risk are calculated.

1. Loss of Component Cooling Water. When component cooling water is lost, the plant will be shut down or tripped. The operator may trip the reactor coolant pumps first, leading to a low flow reactor trip. The loss of component cooling event is analyzed by quantifying the reactor trip event tree with the split fraction for component cooling system failure set to 1.0. Failure of component cooling will not lead to more serious degradation of safety equipment than analyzed here unless the system is drained of all water by a large component cooling water pipe break at the lower elevations of the plant. Such a scenario is very unlikely given the system design and location, as shown in the analysis of Section 1.3.8.2, and is therefore a negligible contributor to risk.

   The frequency of the reactor trip, loss of component cooling water initiating event, ϕ_{12b}, is developed in Section 1.6.1 and is shown with the electric power state split fraction data (conditional

on ϕ_{12b})in Table 1.3.6.12b-1. The other branch point split fraction data for the event tree (conditional on ϕ_{12b} and electric power state) is developed in Sections 1.3.3 and 1.6.2 and is summarized in Table 1.3.6.12b-2.

When mean value data are propagated through the reactor trip event tree, the base case results shown in Table 1.3.6.12b-3 are obtained. No important plant split fractions are dominated by complete or partial failure of electric power.

Dominant sequences are listed in Table 1.3.6.12b-4. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty.

Loss of power at DC power panel 31 or 32 will cause a reactor trip. (Each power panel supplies one of the reactor protection trip logic channels.) Failure of power at DC power panel 33 will deenergize 118 VAC instrument bus 33. This failure should not cause a direct reactor trip unless a trip signal from one of the instrumentation channels that is supplied from the remaining three instrument buses also exists.

2. Loss of DC Power. DC power panel 31 supplies control power to 480V switchgear bus 5A, 6.9 kV bus 5, and diesel generator 33. DC power panel 32 supplies control power to 480V switchgear bus 6A, 6.9 kV bus 6 and diesel generator 32. DC power panel 33 supplies control power to 480V switchgear buses 2A and 3A, 6.9 kV buses 2 and 3, and diesel generator 31. Since buses 5A and 6A are normally energized from the 138 kV offsite power supply, failure of control power at these buses will not cause a loss of AC voltage. Operating equipment will continue to run (the breakers are prevented from opening), but standby equipment circuit breakers are prevented from automatically closing. Because DC power failure at power panel 31 or 32 will cause a reactor trip that could require standby equipment operation, the effects of these DC control power failures are conservatively modeled in this bounding analysis as equivalent to the failure of AC power at the affected bus. Buses 2A and 3A are normally supplied from the unit auxiliary transformer and must be transferred to the station auxiliary transformer following a unit trip. Therefore, if a trip occurs with no DC power available at power panel 33, voltage will be lost at both of these 480V buses. Although it is an unlikely event, it is assumed for this bounding analysis that failure of power at DC power panel 33 will lead to a unit trip with power failure at 480V buses 2A and 3A.

Each DC power panel is powered from its own battery and battery charger. The battery charger normally supplies the DC loads and maintains the battery on a trickle charge. No routinely scheduled tests or maintenance activities that affect the availability of either the charger or the battery are performed during unit power operation. The Indian Point Unit 3 technical specifications allow a battery to be out of service for a maximum period of 24 hours during power operation. If this period is exceeded, the unit must be shut down. Also, if a battery charger is removed from service, the unit must be shut down immediately. For this analysis, it is assumed that equipment is removed from service only for nonroutine maintenance of failed or degraded components. To bound the maintenance unavailability, it is further assumed that for each battery maintenance event the battery is removed from service for the entire allowed period of 24 hours, plus an additional 4 hours to account for the time required to bring the unit to subcritical conditions

using normal shutdown procedures. Each battery charger maintenance event is assumed to span 4 hours before the unit is subcritical. The data in Section 1.6.1 provide the following mean failure rate information for the components included in this analysis:

- Circuit breaker transfers open 2.67×10^{-6}/hour
- Battery charger failure 1.35×10^{-5}/hour
- Battery failure 8.35×10^{-8}/hour
- Fuse opens prematurely 8.32×10^{-7}/hour
- DC bus failure 3.25×10^{-8}/hour

Maintenance of the battery charger supply will be required if either the charger input or output circuit breaker fails of if the charger itself fails. The combined mean failure rate for these components is 1.88×10^{-5} failure/hour. Multiplying this required maintenance frequency by the bounding 4-hour time period results in a mean unavailability from maintenance of the battery charger supply of 7.52×10^{-5}. DC power will be lost at the power panel if either the battery or its output fuse fails when the charger supply is unavailable. The combined mean failure rate for these components is 9.16×10^{-7} failure/hour. Multiplying this failure frequency by the unavailability of the charger power supply results in the mean frequency of DC power panel failures from the combined effects of charger maintenance and battery failures. This is expressed as

$$\phi_{BFCM} = 6.89 \times 10^{-11} \text{ failure/hour}$$

The failure frequency information also indicates that maintenance of the battery supply will occur at a mean frequency of 9.16×10^{-7} events/hour. After applying the 28-hour bounding event duration, the resultant unavailability of this supply because of maintenance is 2.56×10^{-5}. The mean frequency of DC power panel failures from the combined effects of battery maintenance and charger failures is

$$\phi_{BMCF} = 4.81 \times 10^{-10} \text{ failure/hour}$$

DC power will also be lost at a power panel if the panel itself fails ($\phi_{PF} = 3.25 \times 10^{-8}$ failure/hour). The combined mean frequency of power failures at any given DC power panel from these three contributing causes is

$$\phi_{PPF} = \phi_{BFMC} + \phi_{BMCF} + \phi_{PF} = 3.30 \times 10^{-8} \text{ failure/hour}$$

This DC power failure analysis has explicitly included the effect of hardware failures, testing (no contribution), and component maintenance. In addition, for this analysis it is assumed that each battery or battery charger maintenance event involves local

switching actions that could interrupt DC power at the power panel if improperly performed (e.g., the operator could inadvertently open the battery charger output breaker with the battery isolated for maintenance). Section 1.6.1 provides a mean frequency of 4.7×10^{-3} errors/switching event to account for the human error of selecting the wrong breaker during switching operations (ϕ_{SWE}). It is assumed that similar switching operations must be performed to remove a battery or charger from service and to restore it following maintenance. Therefore, each maintenance event contributes two possible sources of error related power failures. From the preceding analysis, the combined mean frequency of maintenance, ϕ_M, for the charger and the battery at a given DC power panel is 1.97×10^{-5} maintenance event/hour. The mean frequency of power failure at the DC power panel because of human errors related to these maintenance events is

$$\phi_{HEF} = \phi_M \cdot \phi_{SWE} \cdot 2 = 1.85 \times 10^{-7} \text{ failure/hour}$$

The total frequency of DC power failure at a given DC power panel because of human error, hardware failure, testing and maintenance effects is approximately

$$\phi_{SF} = \phi_{PPF} + \phi_{HEF} = 2.18 \times 10^{-7} \text{ failure/hour}$$

The mean frequency of reactor trips from these DC power failures, which also cause failure of AC power at a 480V switchgear bus, is the sum of the contributions from DC power panels 31, 32, and 33.

$$\phi_{DCPF} = 3\ \phi_{PF} = 5.73 \times 10^{-3} \text{ event/year}$$

The Indian Point Unit 3 electric power system analysis has shown that the unavailability of power at a 480V switchgear bus following a unit trip from any cause, other than loss of offsite power, is approximately 3.7×10^{-5}. This includes failures at bus 5A, bus 6A, or buses 2A and 3A. This value excludes the effects of operator actions to recover power as does the quantification of DC power failure events previously presented. The combined frequency of reactor trips and transient initiating events (other than the loss of offsite power) used in this study is approximately 10 events/year for Indian Point Unit 3. The unavailability of power at a 480V bus following the loss of offsite power is approximately 9.5×10^{-2}. This includes failures at bus 5A, bus 6A, or buses 2A and 3A. The mean frequency of the loss of offsite power initiating event is approximately 0.27 events/year for Unit 3. Therefore, the combined frequency at which a unit trip occurs and AC power is lost at any one 480V bus (or at buses 2A and 3A) is approximately 2.6×10^{-2} events/year from causes other than the failure of DC control power. Since the DC power failure event frequency previously calculated is very conservative and is bounded by these other event sequences, it does not need to be quantified as a separate initiating event category.

TABLE 1.3.6.12a-1

REACTOR TRIP INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{12a} - Reactor Trip (Annual Frequency)	1.44+0	2.70+0	4.18+0	2.86+0
AC Power Available at Buses (Given ϕ_{12a}):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-2

ET-12a - REACTOR TRIP

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	-	-	-	1.0	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.7-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.7-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	8.1-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-2 (continued)

ET-12a - REACTOR TRIP

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-1	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-2 (continued)

ET-12a - REACTOR TRIP

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12a	Reactor Trip	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-2	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12a-3

INDIAN POINT 3 REACTOR TRIP EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

	PLANT EVENT SEQUENCE CATEGORY[3]																			
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL
M_{12A} = [	NOT MEANINGFUL																			]
M'_{12A} = [	0	0	0	0	6.64-8	2.27-12	2.02-11	7.27-16	9.97-9	6.78-12	1.46-10	1.82-11	0	0	0	0	0	0	0	0]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.12a-4

ET-12a - REACTOR TRIP EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	6.28-8	2,3,5,6	3	L-1, R-3	6.12-8
		5,6	3	L-1, R-3	1.31-9
SLF	2.26-12	2,3,5,6	5	L-1, R-3, CS	2.20-12
SLC	2.01-11	5,6	6	L-1, R-3, CF-2	1.99-11
SL	7.24-16	5,6	8	L-1, R-3, CF-2, CS	7.18-16
TEFC	7.09-8	2,3,5,6	9	L-1, OP-2	6.74-8
		2,3,5	9	L-1	1.42-9
		5(2)[1]	9	L-1	7.99-10
TEF	8.97-12	2,3,5,6	11	L-1, OP-2, CS	2.43-12
		2,3,6	11	L-1, CS	7.51-13
		2,3,5	11	L-1, CS	5.72-12
TEC	1.56-10	2,3,6	12	L-1, CF-2	7.18-12
		5,6	12	L-1, OP-2, CF-2	1.11-11
		5(3)[2]	12	L-1	1.37-10
TE	1.86-11	5(3)[2]	14	L-1, CS	5.50-13
		NP(3)[3]	14	L-1	1.76-11

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1. Initially power at 5A, power recovered in 3 hours.
2. Initially power at 5A, power not recovered in 3 hours.
3. Initially no power, power not recovered in 3 hours.

TABLE 1.3.6.12b-1

REACTOR TRIP (LOSS OF COMPONENT COOLING WATER)
INITIATING EVENT AND ELECTRIC POWER DATA

Description	5%	Median	95%	Mean
ϕ_{12b} - Reactor Trip (Loss of Component Cooling Water) (Annual Frequency)	1.07-6	1.17-4	6.66-3	2.16-3
AC Power Available at Buses (Given ϕ_{12b}):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-2

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING WATER

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling Water	-	-	-	1.0	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.2-3	3.7-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	7.1-5	1.6-3	1.1-2	4.1-3	1.3.3
CF-2	Fan Coolers	1.2-9	1.8-7	1.7-5	2.6-6	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING WATER

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling Water	3.4-7	5.2-6	5.9-5	1.3-5	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	1.1-4	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	1.4-4	4.6-3	1.3-1	3.7-2	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING WATER

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling Water	2.8-7	4.9-6	5.7-5	1.3-5	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	4.2-5	2.7-3	3.3-2	6.9-3	1.3.3
CF-2	Fan Coolers	8.2-8	4.5-6	1.7-4	5.8-5	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING WATER

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling Water	5.1-4	1.3-3	2.8-3	1.5-3	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	1.7-3	3.8-3	8.1-3	4.5-3	1.3.3
R-3	Recirculation Cooling	3.3-4	3.3-3	3.8-2	6.9-3	1.3.3
CF-2	Fan Coolers	6.9-5	2.6-3	5.3-2	1.5-2	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING WATER

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling Water	6.3-9	1.4-7	1.1-6	3.8-7	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING WATER

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling Water	4.0-8	2.1-7	2.9-6	4.3-7	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING WATER

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling Water	3.4-7	7.8-7	1.8-6	9.6-7	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-2 (continued)

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING WATER

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-12b	Reactor Trip, Loss of Component Cooling Water	4.0-8	9.6-8	2.8-7	1.2-7	1.6.1
TT	Turbine Trip	2.6-7	1.6-6	9.5-6	2.8-6	1.3.3
MS-2	MSIV Trip	4.1-3	1.2-2	3.6-2	1.5-2	1.3.3
L-1	AFWS Actuation and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
OP-2	Primary Cooling (Bleed and Feed)	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.12b-3

INDIAN POINT 3 REACTOR TRIP, LOSS OF COMPONENT COOLING EVENT TREE QUANTIFICATION

1. Conditional Split Fractions Without ATWS[1,2]

PLANT EVENT SEQUENCE CATEGORY[3]

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
M_{12B} = [	0	0	0	0	1.51-5	5.45-10	2.89-9	1.04-13	7.00-8	8.96-12	1.54-8	2.02-9	0	0	0	0	0	0	0	0	0]
M'_{12B} = [	NOT REQUIRED																				]

Notes:

1. M = Six-Hour Electric Power Bounding Model

   M' = Results including Electric Power Recovery

2. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

3. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

   A - Large LOCA behavior E - Early melt F - Fan coolers are operating
   S - Small LOCA behavior L - Late melt C - Containment sprays are operating
   T - Transient behavior

TABLE 1.3.6.12b-4

ET-12b - REACTOR TRIP, LOSS OF COMPONENT COOLING
EVENT TREE DOMINANT SEQUENCES

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SLFC	1.51-5	2,3,5,6	3	L-1, R-3	1.49-5
SLF	5.45-10	2,3,5,6	5	L-1, R-3, CS	5.37-10
SLC	2.89-9	2,3,5,6 5,6	6 6	L-1, R-3, CF-2 L-1, R-3, CF-2	2.39-9 4.92-10
SL	1.04-13	2,3,5,6 5,6	8 8	L-1, R-3, CF-2, CS L-1, R-3, CF-2, CS	8.60-14 1.77-10
TEFC	7.00-8	2,3,5,6 2,3,5	9 9	L-1, OP-2 L-1	6.74-8 1.42-9
TEF	8.96-12	2,3,5,6 2,3,6 2,3,5	11 11 11	L-1, OP-2, CS L-1, CS L-1, CS	2.43-12 7.78-13 5.72-12
TEC	1.54-8	5	12	L-1	1.53-8
TE	2.02-9	5 No Power	14 14	L-1, CS L-1	6.14-11 1.92-9

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1.3.6.13 ATWS--Event Tree 13 (ET-13) Quantification

The ATWS event tree is a continuation of all plant event trees except:

- ET-1 and ET-2, large and medium LOCAs--the reactor is initially shut down by voiding in the core region.
- ET-12, reactor trip.

Following failure of reactor trip, the other trees branch to the ATWS tree in a particular state of electric power with split fractions shown as M^{β} in Tables 1.3.6.13-4 through 1.3.6.13-13. The branch point split fraction data for the ATWS tree (conditional on ϕ^1 and electric power state) is developed in Sections 1.3.3 and 1.6.2, and is summarized in Table 1.3.6.13-1.

When mean value data is propagated through the ATWS event tree, the results shown in Table 1.3.6.13-2 are obtained. This is called the 8 x 21 matrix M^{α}. Dominant sequences from the ATWS tree with all AC power available (the most likely state) are listed in Table 1.3.6.13-3. Those that are dominant with respect to risk will be discussed in Section 8 where risk is quantified. The probability of frequency of those sequences will be requantified to properly account for uncertainty. $M^{\alpha}{}_1$ shows the split fractions to each plant event sequence category conditional on an ATWS in an event tree for an initiating event other than a turbine trip for a specific state of electric power. Likewise, $M^{\alpha}{}_1$ shows the split fractions to each plant event sequence category conditional on an ATWS in a turbine trip event tree for a specific state of electric power. The results of the ATWS tree quantification, M^{α}, are combined with ATWS results of the applicable plant event trees, M^{β}, in Tables 1.3.6.13-4 through 1.3.6.13-13.

Event PL has been quantified by reviews of the plant trip data from other plants--Indian Point Unit 2 and Zion Station Units 1 and 2. The approximate power levels for all losses of main feedwater (ϕ_7) and turbine trips (ϕ_{11a}) have been identified. These transients provide most of the input to the ATWS event tree (90% on a mean frequency basis). Based on the Zion Station Units 1 and 2 data (PL > 80% for 48 out of 99 transients) and the Indian Point Unit 2 data which was consistent with the Zion data, a mean value of 0.5 to PL was assigned.

TABLE 1.3.6.13-1

ET-13 - FAILURE TO SCRAM

AC Electric Power at 2A, 3A, 5A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.6.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.3
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	4.3-3	8.5-3	2.1-2	1.1-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.5-1	1.3.3
PR-1	ATWS Pressure Relief	2.5-9	8.2-6	4.3-3	3.6-3	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deenergized and RCCAs Fall	-	-	-	5.8-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	4.5-3	1.3.3
R-3	Recirculation Cooling	-	-	-	4.2-3	1.3.3
CF-2	Fan Coolers	-	-	-	3.2-5	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 2A, 3A, and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.6.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.3
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	1.1-6	7.6-6	8.2-5	1.5-5	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	4.3-3	8.5-3	2.1-2	1.1-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.5-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deenergized and RCCAs Fall	-	-	-	5.8-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	8.5-3	1.3.3
CF-2	Fan Coolers	-	-	-	2.8-3	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11 x 10^{-5}.

TABLE 1.3.6.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 2A, 3A, and 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.6.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.3
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	4.3-3	8.5-3	2.1-2	1.5-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.5-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deenergized and RCCAs Fall	-	-	-	5.8-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	8.5-3	1.3.3
CF-2	Fan Coolers	-	-	-	3.9-6	1.6.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.6.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 5A and 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.6.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.3
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	7.4-3	1.3-2	2.5-2	1.5-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.5-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	6.0-3	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deenergized and RCCAs Fall	-	-	-	5.8-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	4.5.3	1.3.3
R-3	Recirculation Cooling	-	-	-	8.4-3	1.3.3
CF-2	Fan Coolers	-	-	-	2.8-3	1.6.2
CS	Containment Spray	5.5-6	2.8-5	9.8-5	3.6-5	1.6.2
NA	NaOH Addition	4.7-4	8.3-4	1.5-3	9.6-4	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 2A and 3A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.2
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.3
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	-	-	-	1.5-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.5-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deenergized and RCCAs Fall	-	-	-	5.8-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	-	-	-	1.0	1.5.2
NA	NaOH Addition	-	-	-	1.0	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 6A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.2
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.3
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	4.4-5	9.1-5	2.0-4	1.1-4	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	-	-	-	1.5-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.5-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deenergized and RCCAs Fall	-	-	-	5.8-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.5.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.13-1 (continued)

ET-13 - FAILURE TO SCRAM

AC Electric Power at 5A

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.5.2
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.3
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	-	-	-	1.6-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.5-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deenergized and RCCAs Fall	-	-	-	5.8-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.5.2
CS	Containment Spray	1.7-3	3.5-3	7.7-3	4.0-3	1.5.2
NA	NaOH Addition	2.4-4	1.1-3	4.8-3	1.3-3	1.5.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.13-1 (continued)

ET-13 - FAILURE TO SCRAM

No AC Electric Power

Code	Description	5th Percentile	Median	95th Percentile	Mean	Source
ET-13	Failure to Scram	-	-	-	1.0	1.6.1
PL	Power Level Greater Than 80%	-	-	-	0.5	1.3.3
TT-2	Turbine Trip/MSIV Closure	-	-	-	1.8-4	1.3.3
L-1	Auxiliary Feedwater and Secondary Cooling	5.4-3	1.2-2	3.1-2	1.6-2	1.3.3
L-2	Auxiliary Feedwater and Secondary Cooling - ATWS	-	-	-	1.6-2	1.3.3
OP-5	Rods in By 1 Minute	-	-	-	1.5-1	1.3.3
PR-1	ATWS Pressure Relief	-	-	-	1.1-2	1.3.3
SO	Safety Injection Operable	-	-	-	1.0-2	1.3.3
OP-6	Manually Deenergized and RCCAs Fall	-	-	-	5.8-1	1.3.3
PR-2	Secure PR	-	-	-	2.7-1	1.3.3
OP-2	Primary Cooling Bleed and Feed with Emergency Boration	-	-	-	1.0	1.3.3
R-3	Recirculation Cooling	-	-	-	1.0	1.3.3
CF-2	Fan Coolers	-	-	-	1.0	1.6.2
CS	Containment Spray	-	-	-	1.0	1.6.2
NA	NaOH Addition	-	-	-	1.0	1.6.2

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.13-2

INDIAN POINT 3 ATWS EVENT TREE QUANTIFICATION

1. ATWS Split Fractions Given No Previous Turbine Trip for Specific Electric Power States, M_1^{α}

PLANT EVENT SEQUENCE CATEGORY

Power at Buses	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
2A,3A,5A,6A	2.92-04	1.06-08	4.65-08	1.68-12	4.21-04	1.52-08	1.35-08	4.85-13	1.96-04	7.05-09	6.26-09	2.25-13	0	0	0	0	0	0	0	0	0
2A,3A,6A	5.07-02	2.03-04	1.42-04	5.71-07	5.32-05	2.14-07	1.49-07	6.00-10	4.32-02	1.74-04	1.21-04	4.87-07	0	0	0	0	0	0	0	0	0
2A,3A,5A	5.07-02	2.03-04	2.49-07	9.99-10	7.03-05	2.82-07	2.74-10	1.10-12	4.34-02	1.74-04	1.69-07	6.79-10	0	0	0	0	0	0	0	0	0
5A,6A	3.10-04	1.13-08	9.20-07	3.37-11	8.55-04	3.08-08	2.40-06	8.65-11	1.95-04	7.03-09	5.49-07	1.97-11	0	0	0	0	0	0	0	0	0
2A,3A	9.71-04	3.52-08	8.17-08	5.08-02	3.02-05	1.09-09	9.68-10	3.48-14	0	0	0	4.35-02	0	0	0	0	0	0	0	0	0
6A	9.71-04	5.06-02	5.07-02	2.04-04	3.02-05	1.09-09	9.68-10	3.48-14	0	0	4.34-02	1.74-04	0	0	0	0	0	0	0	0	0
5A	1.00-03	5.06-03	5.06-02	2.04-04	3.19-05	1.15-09	1.02-09	3.68-14	0	0	5.06-02	2.03-04	0	0	0	0	0	0	0	0	0
None	1.00-03	3.63-08	5.39-09	5.09-02	3.12-05	1.12-09	1.96-11	7.07-16	0	0	0	5.08-02	0	0	0	0	0	0	0	0	0

2. ATWS Split Fractions Given a Previous Turbine Trip for Specific Electric Power States, M_2^{α}

PLANT EVENT SEQUENCE CATEGORY

Power at Buses	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
2A,3A,5A,6A	2.90-04	1.06-08	4.59-08	1.66-12	4.20-04	1.51-08	1.35-08	4.84-13	1.96-04	7.05-09	6.26-09	2.26-13	0	0	0	0	0	0	0	0	0
2A,3A,6A	5.06-02	2.03-04	1.42-04	5.71-07	5.32-05	2.14-07	1.49-07	6.00-10	4.32-02	1.74-04	1.21-04	4.87-07	0	0	0	0	0	0	0	0	0
2A,3A,5A	5.05-02	2.03-04	2.48-07	9.95-10	6.94-05	2.79-07	2.71-10	1.09-12	4.32-02	1.74-04	1.69-07	6.79-10	0	0	0	0	0	0	0	0	0
5A,6A	3.09-04	1.13-08	9.16-07	3.35-12	1.02-03	3.55-08	2.77-06	9.96-11	1.95-04	7.04-09	5.49-07	1.98-11	0	0	0	0	0	0	0	0	0
2A,3A	9.61-04	3.48-08	8.07-08	5.09-02	2.98-05	1.07-09	9.54-10	3.43-14	0	0	0	4.36-02	0	0	0	0	0	0	0	0	0
6A	9.61-04	3.48-08	5.07-02	2.04-04	2.98-05	1.07-09	9.54-10	3.43-14	0	0	4.34-02	1.74-04	0	0	0	0	0	0	0	0	0
5A	1.00-03	3.63-08	5.17-02	2.08-04	3.15-05	1.13-09	1.01-09	3.63-14	0	0	5.06-02	2.03-04	0	0	0	0	0	0	0	0	0
NP (WR)	3.68-03	5.93-08	6.99-08	2.52-12	4.64-04	1.67-08	1.13-09	4.06-14	2.29-04	8.23-09	5.94-10	2.14-14	0	0	0	0	0	0	0	0	0
No Power	0	0	0	5.94-02	0	0	0	0	0	0	0	5.08-02	0	0	0	0	0	0	0	0	0

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

2. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-3

ET-13 - FAILURE TO SCRAM EVENT TREE DOMINANT SEQUENCES
(All AC Power Available)

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences		
		Sequence	Failed Branch Points	Conditional Frequency
SEFC	2.91-4	23	OP-5, OP-6, OP-2	1.92-4
		37	L-2, SO	5.49-5
		10	OP-5, PR-2, OP-2	3.70-5
		30	OP-5, PR-2, SO	4.45-6
SEF	1.05-8	25	OP-5, OP-6, OP-2, CS	6.93-9
		39	L-2, SO, CS	1.98-9
		12	OP-5, PR-2, OP-2, CS	1.35-9
		32	OP-5, PR-1, SO, CS	1.60-10
		46	TT-2, SO, CS	3.24-11
SEC	4.65-8	26	OP-6, OP-2, CF-2	6.15-9
		40	L-2, SO, CF-2	1.76-9
		13	OP-5, PR-1, SO, PR-2, OP-2, CF-2	1.20-9
		33	OP-5, SO, CF-2	1.42-10
		47	TT-2, SO, CF-2	2.88-11
		SLOCA	SA-1	3.72-8
SE	1.69-12	28	OP-5, OP-6, OP-2, CF-2, CS	2.22-13
		42	L-2 SO, CF-2, CS	6.33-14
		15	OP-5, PR-2, OP-2, CF-2, CS	4.33-14
		35	OP-5, PR-1, SO, CF-2, CS	5.13-15
		SLOCA	SA-1, CS	1.35-12
SLFC	4.21-4	53	PL, OP-5, OP-6, R-3	1.82-4
		17	OP-5, OP-6, R-3	1.79-4

Note: Values are presented in abbreviated scientific notation, e.g., 2.91-4 = 2.91×10^{-4}.

TABLE 1.3.6.13-3 (continued)

ET-13 - FAILURE TO SCRAM EVENT TREE DOMINANT SEQUENCES
(All AC Power Available)

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences		
		Sequence	Failed Branch Points	Conditional Frequency
SLFC		4	OP-5, PR-2, R-2	3.49-5
		36	R-2	2.52-5
SLF	1.52-8	55	PL, OP-5, OP-6, R-3, CS	6.55-9
		19	OP-5, OP-6, R-3, CS	6.44-9
		6	OP-5, PR-2, R-3, CS	1.26-9
		SLOCA	R-2, CS	9.07-10
SLC	1.35-8	56	PL, OP-5, OP-6, R-3, CF-2	5.81-9
		20	OP-5, OP-6, R-3, CF-2	5.71-9
		7	OP-5, PR-2, R-3, CF-2	1.12-9
		SLOCA	CF-1, R-2	8.06-10
SL	4.85-13	58	PL, OP-5, OP-6, R-3, CF-2, CS	2.09-13
		22	OP-5, OP-6, R-3, CF-2, CS	2.06-13
		9	OP-5, PR-2, R-3, CF-2, CS	4.03-14
		SLOCA	CF-1, R-2, CS	2.90-14
TEFC	1.96-4	59	PL, OP-5, OP-6, OP-2	1.96-4
TEF	7.05-9	61	PL, OP-5, OP-6, OP-2, CS	7.05-9
TEC	6.26-9	62	PL, OP-5, OP-6, OP-2, CF-2	6.26-9
TE	2.25-13	64	OP-5, OP-6, OP-2, CF-2, CS	2.25-13

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

TABLE 1.3.6.13-4

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE SMALL LOCA EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
$M^{\beta} \cdot M^{\alpha}$ = [	3.90-5	5.07-10	5.07-10	5.85-8	9.13-13	1.05-12	2.34-12	1.34-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V	
M^{α} = [	1.15-8	6.85-13	2.11-12	5.43-14	1.65-8	5.95-13	6.67-13	2.43-17	7.70-9	4.52-13	5.02-13	1.74-14	0	0	0	0	0	0	0	0	0	]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-5

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE STEAM GENERATOR TUBE RUPTURE EVENT TREE

(to be supplied)

TABLE 1.3.6.13-6

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE STEAM LINE BREAK INSIDE CONTAINMENT EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
H^B = [	3.90-5	5.07-10	5.07-10	5.85-8	1.48-11	1.72-11	3.82-11	5.52-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$H^B \cdot H^C$ = [	1.15-8	1.68-12	4.74-12	7.92-13	1.65-8	5.95-13	6.67-13	2.43-17	7.70-9	4.52-13	3.02-12	6.83-13	0	0	0	0	0	0	0	0	0]

Notes:

Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-7

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE STEAM LINE BREAK OUTSIDE CONTAINMENT EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
H^B = [	3.90-5	5.07-10	5.07-10	5.85-8	1.48-11	1.72-11	3.82-11	5.52-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	T
$H^B \cdot H^n$ = [	1.15-8	1.68-12	4.74-12	7.92-13	1.65-8	5.95-13	6.67-13	2.43-17	7.70-9	4.52-13	3.02-12	6.83-13	0	0	0	0	0	0	0	0	0]

Notes:

Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-8

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE LOSS OF MAIN FEEDWATER EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^B = [	3.90-5	5.07-10	5.07-10	5.85-8	9.13-13	1.05-12	2.34-12	1.34-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^B \cdot M^a$ = [	1.15-8	6.85-13	2.11-12	5.43-14	1.65-8	5.95-13	6.67-13	2.43-17	7.70-9	4.52-13	5.02-13	4.74-14	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-9

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE LOSS OF REACTOR COOLANT SYSTEM FLOW EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{β} = [	3.51-5	4.56-10	4.56-10	5.27-8	1.33-11	1.54-11	3.44-11	4.97-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	1.03-8	1.51-12	4.27-12	7.11-13	1.48-8	5.35-13	6.00-13	2.19-17	6.93-9	4.07-13	2.71-12	6.14-13	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-10

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE CORE POWER EXCURSION EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^E = [	1.37-11	1.77-16	1.77-16	2.05-14	5.19-18	6.01-18	1.34-17	1.93-19]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^E \cdot M^a$ = [	4.02-15	5.89-19	1.66-18	2.78-19	5.79-15	2.09-19	2.34-19	8.52-24	2.70-15	1.58-19	1.06-18	2.39-19	0	0	0	0	0	0	0	0	0]

Notes:

Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

The Plant Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior
E - Early melt
L - Late melt
F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-11

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE TURBINE TRIP EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and None
M^{β} = [	3.90-5	5.07-10	5.07-10	5.85-8	9.13-13	1.05-12	2.34-12	1.43-13]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	1.14-8	6.20-13	2.09-12	5.60-14	1.64-8	5.91-13	6.89-13	2.50-17	7.70-9	4.52-13	5.02-13	4.80-14	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-12

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE TURBINE TRIP LOSS OF POWER EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and 2A,3A,6A	ATWS and 2A,3A,5A	ATWS and 5A, 6A	ATWS and 2A, 3A	ATWS and 6A	ATWS and 5A	ATWS and Power Recovered	ATWS and None
M^{β} = [	2.66-6	2.39-7	2.39-7	2.39-7	6.44-9	6.44-9	6.44-9	1.82-9	1.66-11]

2. Conditional ATWS Contributions

PLANT EVENT SEQUENCE CATEGORY

	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
$M^{\beta} \cdot M^{\alpha}$ = [	2.50-8	9.71-11	6.94-10	3.32-10	1.39-9	1.67-13	7.34-13	1.69-16	2.12-8	8.32-11	6.34-10	2.84-10	0	0	0	0	0	0	0	0	0]

Notes:

1. Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.
2. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.13-13

INDIAN POINT 3 ATWS CONTRIBUTIONS TO THE TURBINE TRIP LOSS OF SERVICE WATER EVENT TREE

1. Split Fractions for ATWS and AC Bus Availability

	ATWS and 2A,3A,5A,6A	ATWS and None
H^6 = [	3.90-5	3.13-9]

2. Conditional ATWS Contributions

	PLANT EVENT SEQUENCE CATEGORY																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	T
$H^6 \cdot H^a$ = [	6.37-11	7.90-15	1.13-8	1.65-10	2.34-7	8.42-12	3.68-6	1.32-10	0	0	7.64-9	1.59-10	0	0	0	0	0	0	0	0	0]

Notes:

Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior

E - Early melt
L - Late melt

F - Fan coolers are operating
C - Containment sprays are operating

1.3.6.14 Tabulated Results

Sections 1.3.6.1 through 1.3.6.12 provided the conditional split fractions from each initiating event without the ATWS contribution. That information from Tables 1.3.6 (.1 through .12)-3 is summarized into the single matrix M (nonATWS) in Table 1.3.6.14-1.

Section 1.3.6.13 provided conditional split fractions from ATWS for each initiating event. The information from Tables 1.3.6.13-4 through 1.3.6.13-13 is summarized into the single matrix M (ATWS) in Table 1.3.6.14-2.

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TABLE 1.3.6.14-1

INDIAN POINT 3 CONTRIBUTION OF ALL NONATWS SEQUENCES

Initiating Event	NonATWS Contributions to Conditional Plant Split Fractions, M (NonAWTS)																				
	Plant Event Sequence Category																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	V
ϕ_1 Large LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	3.01-03	1.33-07	7.19-06	1.26-07	5.34-03	1.97-07	1.87-07	3.78-07	0
ϕ_2 Medium LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	1.00-03	6.10-08	7.62-06	5.06-07	5.35-03	1.97-07	1.68-07	1.23-11	0
ϕ_3 Small LOCA:	1.40-04	2.91-08	6.22-06	4.77-09	4.11-03	1.49-07	3.73-08	2.56-12	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_4 Steam Generator Tube Rupture:	0	0	0	0	0	0	0	0	1.88-05	1.38-09	1.39-06	5.06-07	0	0	0	0	0	0	0	0	0
ϕ_5 Steam Break Inside Containment:	0	0	0	0	6.15-05	2.21-09	2.90-09	1.04-13	6.88-05	4.00-09	4.48-08	9.61-09	0	0	0	0	0	0	0	0	0
ϕ_6 Steam Break Outside Containment:	0	0	0	0	6.15-05	2.21-09	2.90-09	1.04-13	6.88-05	4.00-09	4.48-08	9.61-09	0	0	0	0	0	0	0	0	0
ϕ_7 Loss of Main Feedwater:	0	0	0	0	6.28-08	2.26-12	2.01-11	7.24-16	7.09-08	8.97-12	1.56-10	1.86-11	0	0	0	0	0	0	0	0	0
ϕ_8 Trip of One MSIV:	0	0	0	0	6.27-08	2.26-12	2.01-11	7.24-16	7.00-08	8.94-12	1.54-08	2.02-09	0	0	0	0	0	0	0	0	0
ϕ_9 Loss of RCS Flow:	0	0	0	0	5.64-08	2.03-12	1.81-11	6.52-16	6.30-08	8.04-12	1.38-08	1.82-09	0	0	0	0	0	0	0	0	0
ϕ_{10} Core Power Excursion:	0	0	0	0	2.19-14	7.88-19	7.04-18	2.53-22	2.44-14	3.12-18	5.37-15	7.08-16	0	0	0	0	0	0	0	0	0
ϕ_{11a} Turbine Trip:	0	0	0	0	6.26-08	2.25-12	2.01-11	7.24-16	7.07-08	8.96-12	1.56-10	1.86-11	0	0	0	0	0	0	0	0	0
ϕ_{11b} Turbine Trip, Loss of Offsite Power:	1.01-05	3.68-10	2.25-08	2.36-06	4.21-07	3.38-11	2.33-11	2.70-14	9.63-07	1.50-10	7.42-08	8.04-10	0	0	0	0	0	0	0	0	0
ϕ_{11c} Turbine Trip, Loss of Service Water:	0	0	0	0	0	0	1.49-5	5.38-10	0	0	6.74-8	2.40-5	0	0	0	0	0	0	0	0	0
ϕ_{12a} Reactor Trip:	0	0	0	0	6.28-08	2.26-12	2.01-11	7.24-16	7.09-08	8.97-12	1.56-10	1.86-11	0	0	0	0	0	0	0	0	0
ϕ_{12b} Reactor Trip - Loss of Component Cooling Water:	0	0	0	0	1.51-5	5.45-10	2.89-9	1.04-13	7.00-8	8.96-12	1.54-8	2.02-9	0	0	0	0	0	0	0	0	0
ϕ_V Interfacing Systems LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}

The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior
T - Transient behavior
E - Early melt
L - Late melt
F - Fan coolers are operating
C - Containment sprays are operating

TABLE 1.3.6.14-2

INDIAN POINT 3 CONTRIBUTION OF ALL ATWS SEQUENCES

Initiating Event	ATWS Contributions to Conditional Plant Split Fractions, M(ATWS) — Plant Event Sequence Category																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	VE
ϕ_1 Large LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_2 Medium LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_3 Small LOCA:	2.88-07	1.04-11	9.82-12	2.34-13	7.94-08	2.87-12	3.00-11	9.65-12	8.69-10	4.12-14	4.99-13	8.75-14	0	0	0	0	0	0	0	0	0
ϕ_4 Steam Generator Tube Rupture:	4.39-11	1.58-15	6.58-13	6.05-14	1.20-11	4.37-16	2.66-11	2.42-12	1.32-13	6.28-18	4.37-13	5.10-14	0	0	0	0	0	0	0	0	0
ϕ_5 Steam Break Inside Containment:	2.88-07	1.04-11	9.82-12	1.90-13	7.94-08	2.87-12	3.01-11	7.86-12	8.69-10	4.12-14	5.00-13	5.09-14	0	0	0	0	0	0	0	0	0
ϕ_6 Steam Break Outside Containment:	2.88-07	1.04-11	9.82-12	1.90-13	7.94-08	2.87-12	3.01-11	7.86-12	8.69-10	4.12-14	5.00-13	5.09-14	0	0	0	0	0	0	0	0	0
ϕ_7 Loss of Main Feedwater:	2.88-07	1.04-11	9.82-12	2.34-13	7.94-08	2.87-12	3.01-11	9.65-12	8.69-10	4.12-14	4.99-13	8.75-14	0	0	0	0	0	0	0	0	0
ϕ_8 Trip of One MSIV:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_9 Loss of RCS Flow:	2.59-07	9.39-12	8.85-12	1.71-13	7.14-08	2.58-12	2.71-11	7.07-12	7.82-10	3.71-14	4.50-13	4.58-14	0	0	0	0	0	0	0	0	0
ϕ_{10} Core Power Excursion:	1.01-13	3.66-18	3.44-18	6.67-20	2.78-14	1.00-18	1.05-17	2.75-18	3.05-16	1.44-20	1.75-19	1.78-20	0	0	0	0	0	0	0	0	0
ϕ_{11a} Turbine Trip:	2.88-07	1.04-11	9.82-12	2.34-13	7.94-08	2.87-12	3.00-11	9.65-12	8.69-10	4.12-14	4.99-13	8.75-14	0	0	0	0	0	0	0	0	0
ϕ_{11b} Turbine Trip, Loss of Offsite Power:	1.68-06	9.94-10	1.26-08	3.27-09	6.31-09	2.28-13	1.43-11	5.22-16	2.45-07	9.34-10	1.08-08	3.25-09	0	0	0	0	0	0	0	0	0
ϕ_{11c} Turbine Trip, Loss of Service Water:	0	0	2.88-7	1.79-10	0	0	1.93-5	7.43-9	0	0	8.66-10	1.44-10	0	0	0	0	0	0	0	0	0
ϕ_{12a} Reactor Trip:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_{12b} Reactor Trip - Loss of Component Cooling Water:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ϕ_V Interfacing Systems LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

NOTES: 1. Mean values for conditional frequency of entering each Plant Event Sequence Category given that a specific initiating event has occurred

2. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior E - Early Melt F - Fan Coolers are operating
T - Transient behavior L - Late Melt C - Containment Sprays are operating

1.3.7 REFERENCES

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1.3-16 Tauche, W., "Loss of Feedwater Induced Loss of Coolant Accident Analysis Report," WCAP-9744, May 1980.

1.3-17 U.S. Nuclear Regulatory Commission, "Reactor Safety Study: An Assesment of Accident Risks in U.S. Commercial Nuclear Power Plants," WASH-1400 (NUREG-75/014), October 1975.

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1.3-23 Emergency Operating Procedures, Indian Point No. 3.

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1.3-33 Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Analysis (SSPSA) Operator Action and Main Steam Function Analyses," December 1983.

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1.3.8 APPENDICES

1.3.8.1 INDIAN POINT UNIT 2 LOSS OF COMPONENT COOLING WATER DUE TO A PIPE BREAK

1.3.8.1.1 Introduction

Failure of the component cooling system will not lead to serious degradation of safety equipment unless the system is drained. Such a condition occurs only if a pipe break occurs low in the system beyond the capability of makeup systems. Such a scenario is not quantified under the reactor trip due to loss of component cooling event tree discussion (Section 1.3.5.12.2) because it is not a significant contributor. This appendix shows that the original component cooling system pipe break frequency of 1.36×10^{-4} per year used in the IPPSS should actually be reduced by multiplying by a factor of 3.47×10^{-3} to yield a revised frequency of 4.72×10^{-7} per reactor year.

The primary reason for concern about a component cooling system pipe break is that it could lead to a reactor coolant pump seal LOCA. This sequence of events could cause a core melt. Given the relatively small chance that city water would not be connected to the charging pumps in the time required to prevent the seal LOCA (from 1 to 10 hours),* the contribution of this scenario to core melt frequency or the frequency of any plant damage state is truly negligible.

*See Reference 1.3.8.1-1.

1.3.8.1.2 Discussion

The frequency of rupture for component cooling system piping, a low energy system (120°F, 115 psi), should be less than that for high energy (high temperature and pressure) cooling systems because the component cooling system piping is operated at a higher ratio of design pressure to operating pressure. The ratio of design pressure to system working pressure for PWRs and BWRs is about 1.10 to 1.25. The ratio of design pressure (150 psig) to operating pressure (about 115 psig) for the component cooling system is 1.30. The higher ratio of design pressure to operating pressure is a measure of additional safety margin for the component cooling system for general causes of pipe failure.

The component cooling system at Indian Point 2 was examined against possible specific causes of pipe crack or rupture. A piping inspection documented in Reference 1.3.8.1-2 evaluated and identified locations where the Indian Point 2 component cooling system could be rendered inoperable by impacts from heavy objects (i.e., forklift trucks, block and tackle, dropping objects, etc.). The results of this inspection are summarized in Table 1.3.8.1-1. Reference 1.3.8.1-3 evaluates the penetration loads which are required to puncture the system beyond the capability of the makeup system. Reference 1.3.8.1-4 evaluates additional causes of piping failure such as fatigue and brittle fracture. Based on these studies, it was concluded that the probability of developing a leak large enough to exceed makeup capacity is extremely small. The analytic evaluations of pipe failure presented in these references can be applied to quantify the frequency of large component cooling pipe breaks by adjusting the failure frequency for high energy systems.

Possible causes of component cooling system pipe failure are examined in Reference 1.3.8.1-4. A Licensee Event Report (LER) study (421 LERs, 1960 to 1981), cited in that reference, showed that at least one-half of the pipes developed slow leaks before failure. No "break-before-leak" LERs were reported. Some LERs had incomplete data and therefore it could not be conclusively shown that none were experienced. Another study (WASH-1400, page III-77) of nonnuclear power utility piping showed that 94% of piping failures were preceded by leakage. This 94% value is probably low since the pipe was nonnuclear power utility piping which did not receive the quality assurance, inservice inspection, and detailed design that nuclear piping receives. Even though the component cooling system pipe is of higher quality and the probability of "break-before-leak" is lower, the 94% value will be used. The component cooling system is located in the primary auxiliary building (PAB) and is accessible during plant operation. Besides personal inspection, there are many alarms (discussed in Reference 1.3.8.1-2) which would indicate a loss of inventory from the component cooling system. If the component cooling system developed a slow leak which even remotely could lead to pipe failure, the leak (in most cases) could be temporarily repaired and the plant shut down. Piping failures preceded by slow leaks should not be included in the frequency of LOCAs due to component cooling system pipe failure.

A representative list (Reference 1.3.8.1-4, Table 4) of pipe failure causes and their relative contributions (the fraction of failures by each cause) is:

Cause	Contribution
Corrosion	0.105
Fatigue	0.264
Erosion (cavitation)	0.068
Installation Error (includes faulty repair welds)	0.207
Construction Error	0.020
Design Error	0.024
Fabrication Error	0.010
Maintenance Error	0.007
Miscellaneous and Unknown	0.295
Total	1.000

The contribution to the failure frequency of the component cooling system leading to a LOCA for each cause should, conservatively, be reduced by 94% to account for the elimination of the "leak-before-break" cases. The new contribution to the failure frequency for each cause is as follows:

Cause	Contribution
Corrosion	6.30-3*
Fatigue	1.58-2
Erosion (cavitation)	4.08-3
Installation Error (includes faulty repair welds)	1.24-2
Construction Error	1.20-3
Design Error	1.44-3
Fabrication Error	6.00-4
Maintenance Error	4.20-4
Miscellaneous and Unknown	1.77-2
Total	0.060**

There remains the possibility, however remote, that a catastrophic failure could occur to the component cooling system piping. These failure categories (i.e., impacts, brittle fracture, fatigue failure) should be quantified in extending our state of knowledge beyond the generic reactor plant LER pipe study presented in Reference 1.3.8.1-4.

*6.30-3 is equivalent to 6.30×10^{-3} or 0.00630.
**0.060 due to no leak before failure + 0.940 due to leak before failure = 1.000.

Correction factors for each potential cause of failure are therefore used to quantify the frequency of pipe failure when compared to the frequency of failure of high energy piping systems. The causes, frequency correction factors based on the analyses in References 1.3.8.1-2 through 1.3.8.1-4, and the resultant percentages (final contributions) of the total failure frequency as compared to the failure frequency for high energy systems are as follows:

Cause	Contribution	Frequency Correction Factor	Final Contribution
Corrosion	6.30-3	0.10	6.30-4
Fatigue	1.58-2	0.05	7.90-4
Erosion	4.08-3	0.02	8.16-5
Installation Errors (including faulty repair welds)	1.24-2	0.01	1.24-4
Construction Error	1.20-3	0.01	1.20-5
Design Error	1.44-3	0.01	1.44-5
Fabrication Error	6.00-4	0.01	6.00-6
Maintenance Error	4.20-4	0.10	4.20-5
Miscellaneous and Unknown	1.77-2	0.10	1.77-3
Total	0.060	--	3.47-3

A short description of the basis for each reduction factor is listed below:

- Corrosion. The component cooling system is maintained under stringent chemistry control. The system is always operating and therefore not subject to specialized forms of corrosion as found in stagnant or standby systems. The reduction in failure frequency is judged to be at least 90%.

- Fatigue. The component cooling system does not experience wide temperature fluctuations and is therefore not particularly susceptible to thermal fatigue. Crack initiation and propagation due to fatigue, possibly the highest potential contributor to piping failure, is extremely remote as discussed in Reference 1.3.8.1-4. The piping is well supported and of heavy gauge and is therefore not particularly susceptible to vibration. The reduction in the failure frequency is judged to be at least 95%.

- Erosion. The component cooling system pumps have sufficient suction pressure because of the surge tank so that erosion due to pump cavitation is not expected. The maximum velocity of the water in the component cooling system main piping is comparatively low so that fluid erosion is very unlikely. The component cooling system is a closed loop system under strict chemistry control. The intrusion of foreign erosive particles (i.e., sand, marine growth, etc.) is not expected. The component cooling system water is maintained essentially free of erosive particles. The reduction in the failure frequency is judged to be at least 98%.

- Installation, Construction, Design, and Fabrication Error. The component cooling system at Indian Point 2 has been in operation at least as long as the plant has been in commercial operation (July 1974). This length of operation (currently about 9 years) should be sufficient to detect these types of causes since failure due to these causes should have already occurred. The reduction in the failure frequency is judged to be at least 99% for each of these cause categories.

- Maintenance Error. Most of the maintenance on the component cooling system is performed when the plant is shut down or during refueling since this system is required for plant operation. When maintenance is performed on a standby or installed spare component (i.e., a standby component cooling pump), that portion of the system is tested before returning the entire system to a normal or 100% operable state. The reduction in the failure frequency is judged to be at least 90%.

- Miscellaneous and Unknown. This cause category for component cooling system piping failure includes theorized catastrophic failures due to diverse failure mechanisms such as brittle fracture or impacts damaging the pipe beyond the makeup capacity of the system. The study in Reference 1.3.8.1-4 concludes that failure due to brittle fracture is extremely remote. The study in Reference 1.3.8.1-2 identifies potential locations where the component cooling system could be subjected to impacts. Because of the resiliency of the component cooling piping (discussed in Reference 1.3.8.1-3) and the low probability that an impact will occur, it is extremely unlikely that the component cooling system would fail due to a hypothesized impact. The reduction in the failure frequency is judged to be at least 90% to allow for causes that have not been identified but could contribute to the failure of the component cooling system.

1.3.8.1.3 References

1.3.8.1-1. Letter (with attachment) from J. C. Butler of Westinghouse Electric Corporation to M. Kazarians of Pickard, Lowe and Garrick, Inc., November 22, 1982.

1.3.8.1-2. Pickard, Lowe and Garrick, Inc., "Indian Point 2 Component Cooling System Piping Inspection Report," December 1983.

1.3.8.1-3. Swanson Service Corporation, "An Evaluation of Penetration Loads for Pipings," February 1983.

1.3.8.1-4. Swanson Service Corporation, "Component Cooling Water Rupture Analysis," January 1983.

TABLE 1.3.8.1-1

INDIAN POINT 2 COMPONENT COOLING SYSTEM EFFECTS OF PIPE FAILURE FROM IMPACTS

Number	Location	Pipe Section*	Diameter (inches)	Component Cooling System Failure Potential	Comments
1	Elevation 80' of PAB	53 - component cooling heat exchanger 21 discharge header and discharge isolation valve 765A.	14	Yes (if damage occurs downstream of valve 765A).	Damage may be isolated.
2	Elevation 80' of PAB	53 - component cooling pump discharge headers (upstream of each pump discharge valve, downstream of the 20-inch component cooling pump combined header).	10	Yes.	
3	Elevation 80' of PAB	89 - component cooling evaporator product cooler inlet isolation valve 1850 and outlet isolation valve 1851.	4	Possibly (if damage occurs upstream or downstream of the component cooling isolation valves).	
4	Elevation 98' of PAB	53 - component cooling pump combined discharge header.	20	Yes.	
5	Elevation 98' of PAB	53 - component cooling heat exchanger inlet piping and isolation valve 766A.	14	Yes (if damage occurs upstream of valve 766A).	Damage may be isolated.
6	Elevation 98' of PAB	42 - component cooling surge tank line.	4	Yes.	
7	Elevation 98' of PAB	148, 149 - component cooling supply and return to the nonregenerative heat exchanger.	6	Yes (if damage occurs upstream of the inlet isolation valve 810, or downstream of the outlet isolation valve 814).	
8	Elevation 80' of PAB	152 - component cooling supply and return to waste gas compressor 21 and 22.	2	No (small pipe).	Makeup capacity of 150 gpm is sufficient.

*Pipe section numbers (e.g., 53) correspond to pipe section segments in the piping and instrumentation drawings (UE&C 9321-F-2720-37).

1.3.8.2 INDIAN POINT UNIT 3 LOSS OF COMPONENT COOLING WATER DUE TO A PIPE BREAK

1.3.8.2.1 Introduction

Failure of the component cooling system will not lead to serious degradation of safety equipment unless the system is drained. Such a condition occurs only if a pipe break occurs low in the system beyond the capability of makeup systems. Such a scenario is not quantified under the reactor trip due to loss of component cooling event tree discussion (Section 1.3.6.12.2) because it is not a significant contributor. This appendix shows that the original component cooling system pipe break frequency of 1.28×10^{-4} per year used in the IPPSS should actually be reduced by multiplying by a factor of 3.47×10^{-3} to yield a revised frequency of 4.44×10^{-7} per reactor year.

The primary reason for concern about a component cooling system pipe break is that it could lead to a reactor coolant pump seal LOCA. This sequence of events could cause a core melt. Given the relatively small chance that city water would not be connected to the charging pumps in the time required to prevent the seal LOCA (from 1 to 10 hours),* the contribution of this scenario to core melt frequency or the frequency of any plant damage state is truly negligible.

*See Reference 1.3.8.2-1.

1.3.8.2.2 Discussion

The frequency of rupture for component cooling system piping, a low energy system (120°F, 115 psi), should be less than that for high energy (high temperature and pressure) cooling systems because the component cooling system piping is operated at a higher ratio of design pressure to operating pressure. The ratio of design pressure to system working pressure for PWRs and BWRs is about 1.10 to 1.25. The ratio of design pressure (150 psig) to operating pressure (about 115 psig) for component cooling system is 1.30. The higher ratio of design pressures to operating pressures is a measure of additional safety margin for the component cooling system for general causes of pipe failure.

The component cooling system at Indian Point 3 was examined against possible specific causes of pipe crack or rupture. A piping inspection documented in Reference 1.3.8.2-2 evaluated and identified locations where the Indian Point 3 component cooling system could be rendered inoperable by impacts from heavy objects (i.e., forklift trucks, block and tackle, dropping objects, etc.). The results of this inspection are summarized in Table 1.3.8.2-1. Reference 1.3.8.2-3 evaluates the penetration loads which are required to puncture the system beyond the capability of the makeup system. Reference 1.3.8.2-4 evaluates additional causes of piping failure such as fatigue and brittle fracture. Based on these studies, it was concluded that the probability of developing a leak large enough to exceed makeup capacity is extremely small. The analytic evaluations of pipe failure presented in these references can be applied to quantify the frequency of large component cooling pipe breaks by adjusting the failure frequency for high energy systems.

Possible causes of component cooling system pipe failure are examined in Reference 1.3.8.2-4. A Licensee Event Report (LER) study (421 LERs, 1960 to 1981), cited in that reference, shows that at least one-half of the pipes developed slow leaks before failure. No "break-before-leak" LERs were reported. Some LERs had incomplete data and therefore it could not be conclusively shown that none were experienced. Another study (WASH-1400, page III-77) of nonnuclear power utility piping showed that 94% of piping failures were preceded by leakage. This 94% value is probably low since the pipe was nonnuclear power utility piping which did not receive the quality assurance, inservice inspection, and detailed design that nuclear piping receives. Even though the component cooling system pipe is of higher quality and the probability of "break-before-leak" is lower, the 94% value will be used. The component cooling system is located in the primary auxiliary building (PAB) and is accessible during plant operation. Besides personal inspection, there are many alarms (discussed in Reference 1.3.8.2-2) which would indicate a loss of inventory from the component cooling system. If the component cooling system developed a slow leak, which even remotely could lead to pipe failure, the leak (in most cases) could be temporarily repaired and the plant shut down. Piping failures preceded by slow leaks should not be included in the frequency of LOCAs due to component cooling system pipe failure.

A representative list (Reference 1.3.8.2-4, Table 4) of pipe failure causes and their relative contributions (the fraction of failures by each cause) is:

Cause	Contribution
Corrosion	0.105
Fatigue	0.264
Erosion (cavitation)	0.068
Installation Error (includes faulty repair welds)	0.207
Construction Error	0.020
Design Error	0.024
Fabrication Error	0.010
Maintenance Error	0.007
Miscellaneous and Unknown	0.295
Total	1.000

The contribution to the failure frequency of the component cooling system leading to a LOCA for each cause should, conservatively, be reduced by 94% to account for the elimination of the "leak-before-break" cases. The new contribution to the failure frequency for each cause is as follows:

Cause	Contribution
Corrosion	6.30-3*
Fatigue	1.58-2
Erosion (cavitation)	4.08-3
Installation Error (includes faulty repair welds)	1.24-2
Construction Error	1.20-3
Design Error	1.44-3
Fabrication Error	6.00-4
Maintenance Error	4.20-4
Miscellaneous and Unknown	1.77-2
Total	0.060**

There remains the possibility, however remote, that a catastrophic failure could occur to the component cooling system piping. These failure categories (i.e., "impacts," brittle fracture, fatigue failure) should be quantified in extending our state of knowledge beyond the generic reactor plant LER pipe study presented in Reference 1.3.8.2-4. Correction factors for each potential cause of failure are therefore used to quantify the frequency of pipe failure when compared to the frequency

*6.30-3 is equivalent to 6.30×10^{-3} or 0.00630.
**0.060 due to no leak before failure + 0.940 due to leak before failure = 1.000.

of failure of high energy piping systems. The causes, frequency correction factors based on the analyses in Reference 1.3.8.2-2 through 1.3.8.2-4, and the resultant percentages (final contributions) of the total failure frequency as compared to the failure frequency for high energy systems are as follows:

Cause	Contribution	Frequency Correction Factor	Final Contribution
Corrosion	6.30-3	0.10	6.30-4
Fatigue	1.58-2	0.05	7.90-4
Erosion	4.08-3	0.02	8.16-5
Installation Error (including faulty repair welds)	1.24-2	0.01	1.24-4
Construction Error	1.20-3	0.01	1.20-5
Design Error	1.44-3	0.01	1.44-5
Fabrication Error	6.00-4	0.01	6.00-6
Maintenance Error	4.20-4	0.10	4.20-5
Miscellaneous and Unknown	1.77-2	0.10	1.77-3
Total	0.060	--	3.47-3

A short description of the basis for each reduction factor is listed below:

- Corrosion. The component cooling system is maintained under stringent chemistry control. The system is always operating and therefore not subject to specialized forms of corrosion as found in stagnant or standby systems. The reduction in failure frequency is judged to be at least 90%.

- Fatigue. The component cooling system does not experience wide temperature fluctuations and is therefore not particularly susceptible to thermal fatigue. Crack initiation and propagation due to fatigue, possibly the highest potential contributor to piping failure, is extremely remote as discussed in Reference 1.3.8.2-4. The piping is well supported and of heavy gauge and is therefore not particularly susceptible to vibration. The reduction in the failure frequency is judged to be at least 95%.

- Erosion. The component cooling system pumps have sufficient suction pressure because of the surge tank so that erosion due to pump cavitation is not expected. The maximum velocity of the water in component cooling system main piping is comparatively low so that fluid erosion is very unlikely. The component cooling system is a closed loop system under strict chemistry control. The intrusion of foreign erosive particles (i.e., sand, marine growth, etc.) is not expected. The component cooling system water is maintained essentially free of erosive particles. The reduction in the failure frequency is judged to be at least 98%.

- Installation, Construction, Design, and Fabrication Error. The component cooling system at Indian Point 3 has been in operation at least as long as the plant has been in commercial operation (August 1976). This length of operation (currently about 7 years) should be sufficient to detect these types of causes since failure due to these causes should have already occurred. The reduction in the failure frequency is judged to be at least 99% for each of these cause categories.

- Maintenance Error. Most of the maintenance on the component cooling system is performed when the plant is shut down or during refueling since this system is required for plant operation. When maintenance is performed on a standby or installed spare component (i.e., a standby component cooling pump), that portion of the system is tested before returning the entire system to a normal or 100% operable state. The reduction in the failure frequency is judged to be at least 90%.

- Miscellaneous and Unknown. This cause category for component cooling system piping failure includes theorized catastrophic failures due to diverse failure mechanisms such as brittle fracture or "impacts" damaging the pipe beyond the makeup capacity of the system. The study in Reference 1.3.8.2-4 concludes that failure due to brittle fracture is extremely remote. The study in Reference 1.3.8.2-2 identifies potential locations where the component cooling system could be subjected to impacts. Because of the resiliency of the component cooling piping (discussed in Reference 1.3.8.2-3) and because of the low probability that an impact will occur, it is extremely unlikely that the component cooling system would fail due to a hypothesized impact. The reduction in the failure frequency is judged to be at least 90% to allow for causes that have not been identified but could contribute to the failure of the component cooling system.

1.3.8.2.3 References

1.3.8.2-1 Letter (with attachment) from J. C. Butler of Westinghouse Electric Corporation to M. Kazarians of Pickard, Lowe and Garrick, Inc., November 22, 1982.

1.3.8.2-2 Pickard, Lowe and Garrick, Inc., "Indian Point 3 Component Cooling System Piping Inspection Report," December 1983.

1.3.8.2-3 Swanson Service Corporation, "An Evaluation of Penetration Loads for Pipings," February 1983.

1.3.8.2-4 Swanson Service Corporation, "Component Cooling Water Rupture Analysis," January 1983.

TABLE 1.3.8.2-1

INDIAN POINT 3 COMPONENT COOLING SYSTEM EFFECTS OF PIPE FAILURE FROM IMPACTS

Number	Location	Pipe Section*	Diameter (inches)	Component Cooling System Failure Potential	Comments
1	Elevation 73' of PAB	209 - component cooling heat discharge crosstie header in the vicinity of valves 759C and 759D.	14	Yes (one or both headers).	May split the system and recover on-half system (operator action required).
2	Elevation 73' of PAB	199 - component cooling pump discharge header 31 to component cooling heat exchanger 31 in the vicinity of valve 759A.	14	Yes.	Same as above.
3	Elevation 73' of PAB	515 - component cooling heat exchanger 32 discharge header to the seal water heat exchanger and boric evaporators.	8	Yes.	Same as above.
4	Elevation 73' of PAB	515 - from the seal water heat exchanger and boric acid evaporators to the suction of component cooling pump 33.	8	Yes.	Same as above.
5	Elevation 73' of PAB	148 - component cooling heat exchanger 32 discharge header to the nonregenerative heat exchanger in the vicinity of valve 810.	6	Yes (if damage occurs upstream of valve 810).	Same as above.
6	Elevation 73' of PAB	149 - from the nonregenerative heat exchanger in the vicinity of valve 814 to the suction of component cooling pump 33.	6	Yes (if damage occurs down-stream of valve 814).	Same as above.
7	Elevation 55' of PAB	Component cooling heat exchanger 31 outlet isolation valve 765A and discharge pipe.	14	Yes.	Same as above.
8	Elevation 55' of PAB	Component cooling pump discharge pipe to component cooling pump discharge crosstie header. 199 - component cooling pump 31 209 - component cooling pump 32 211 - component cooling pump 33	10	Yes (one or both headers).	Same as above.

*Pipe section numbers (e.g., 53) correspond to pipe section segments in the piping and instrumentation drawings (UE&C 9321-F-27203-12) and 9321-F-27513-16.

TABLE 1.3.8.2-1 (continued)

Number	Location	Pipe Section*	Diameter (inches)	Component Cooling System Failure Potential	Comments
9	Elevation 41' of PAB	53 - component cooling heat exchanger 32 discharge header in the vicinity of valve A502.	16	Yes.	Same as above.
10	Elevation 41' of PAB	53 - component cooling heat exchanger discharge crosstie and valves 766C and 766D.	12	Yes (one or both headers).	Same as above.

*Pipe section numbers (e.g., 53) correspond to pipe section segments in the piping and instrumentation drawings (UE&C 9321-F-27203-12 and 9321-F-27513-16).

1.4 ACCIDENT SEQUENCE ANALYSIS RESULTS

This section summarizes the results of the plant analysis. Recall that the objective of the plant analysis is to quantify internal event sequences. External events are treated separately in Section 7 using the plant models developed here. Plant event sequences map initiating events into the plant event sequence categories or plant states. These categories group the core melt sequences according to the ex-vessel containment conditions expected at vessel melt-through. This grouping provides the definition of plant conditions necessary to permit meaningful analysis of containment response.

The plant analysis was performed in the five basic phases displayed in Figure 1.0-1:

- Phase A: Establish initiating event categories
- Phase B: Develop event trees
- Phase C: Develop a state of knowlege data base
- Phase D: Analyze key systems
- Phase E: Quantify plant analysis

Phases A, C, and E are combined to develop the initiating event vector, ϕ^I. All five phases are combined to develop the plant matrix M. The results for ϕ^I and M are presented below. Detailed reports on phases C and D, the data bases and systems analyses, are presented in the appendices (Sections 1.5.1 and 1.5.2 for Indian Point 2 and Sections 1.6.1 and 1.6.2 for Indian Point 3). Finally, the combined results for core melt frequency, $\phi^I M$, and public health risk, $\phi^I MCS$, including uncertainty are assembled in Section 8.

1.4.1 INDIAN POINT 2 RESULTS

1.4.1.1 The Indian Point 2 Internal Initiating Event Vector, ϕ^I

The internal initiating event frequencies are assembled into the row vector, ϕ^I, in Table 1.4.1-1. The uncertainties in the initiating event frequencies are displayed in Figure 1.4.1-1. Notice the obvious groupings:

- Frequent Transients with Narrow Uncertainties - Loss of Main Feedwater (LMFW), Turbine Trip (TT), and Reactor Trip (RT).

- Infrequent Transients with Broad Uncertainties - Small LOCA (SLOCA), Steam Generator Tube Rupture (SG), Trip of One MSIV (MSIV), Loss of RCS Flow (LFLOW), Core Power Excursion ($\Delta\rho$), and Turbine Trip - Loss of Offsite Power (LOP).

- Rare Events with Very Broad Uncertainties - Large LOCA (LLOCA), Medium LOCA (MLOCA), Steam Breaks Inside Containment (STMBRKS), Steam Breaks Outside Containment (STMBRKS), Turbine Trip - Loss of Service Water (LSW), and Reactor Trip - Loss of Component Cooling (LCC).

- Extremely Rare Events with Extremely Broad Uncertainties - Interfacing System LOCA (V).

Generic prior and Indian Point 2 posterior distributions are compared in Figures 1.4.1-2 through 1.4.1-16.

1.4.1.2 The Indian Point 2 Internal Event Plant Matrix, M

The results of all mean value event tree quantifications are assembled into the plant matrix, M, in Table 1.4.1-2. The m_{ij} are the conditional split fractions of leaving the plant event trees in plant event sequence category j, given that initiating event i has occurred.

To better understand the significance of the elements of M, return to the large LOCA event tree (ET-1) of Figure 1.3.4.1-1. The tree begins with the large LOCA, ϕ_1^I. It maps the progress of each sequence to eventual success or to a specific plant event sequence category. The results of the large LOCA event tree calculations can be summarized by combining (adding would be appropriate if the sequences were independent) the frequencies of all sequences within each category. For example, sequences 4 and 8 go to category ALC. Row 1 of the M matrix is the result of this summation. Each element in the row is the conditional frequency of ending in the associated plant event sequence category, given that a large LOCA has occurred. Therefore, if a large LOCA occurs, the chance of reaching ALFC is 5.4×10^{-3}.

1.4.1.3 Dominant Contributors at Indian Point 2

The dominant sequences for each plant event sequence category are described in the individual event tree analyses which present the conditional frequency of going to a specific plant exit state, given that a particular initiating event has occurred. In Section 8 the results, including uncertainty,

$$\phi_X = \phi^I MCS$$

and all partial products of ϕ^I, M, C, and S are calculated. Dominant sequences are given for each result.

1.4.2 INDIAN POINT 3 RESULTS

1.4.2.1 The Indian Point 3 Internal Initiating Event Vector, ϕ^I

The internal initiating event frequencies are assembled into the row vector, ϕ^I, in Table 1.4.2-1. The uncertainties in the initiating event frequencies are displayed in Figure 1.4.2-1. Notice the obvious groupings:

- Frequent Transients with Narrow Uncertainties - Loss of Main Feedwater (LMFW), Turbine Trip (TT), and Reactor Trip (RT).

- Infrequent Transients with Broad Uncertainties - Small LOCA (SLOCA), Steam Generator Tube Rupture (SG), Trip of One MSIV (MSIV), Loss of RCS Flow (LFLOW), Core Power Excursion ($\Delta\rho$), and Turbine Trip - Loss of Offsite Power (LOP).

- Rare Events with Very Broad Uncertainties - Large LOCA (LLOCA), Medium LOCA (MLOCA), Steam Breaks Inside Containment (STMBRKS), Steam Breaks Outside Containment (STMBRKS), Turbine Trip - Loss of Service Water (LSW), and Reactor Trip - Loss of Component Cooling (LCC).

- Extremely Rare Events with Extremely Broad Uncertainties - Interfacing System LOCA (V).

Generic prior and Indian Point 3 posterior distributions are compared in Figures 1.4.2-2 through 1.4.2-16.

1.4.2.2 The Indian Point 3 Internal Event Plant Matrix, M

The results of all mean value event tree quantifications are assembled into the plant matrix, M, in Table 1.4.2-2. The m_{ij} are the conditional split fractions of leaving the plant event trees in plant event sequence category j, given that initiating event i has occurred.

1.4.2.3 Dominant Contributors at Indian Point 3

The dominant sequences for each plant event sequence category are described in the individual event tree analyses which present the conditional frequency of going to a specific plant exit state, given that a particular initiating event has occurred. In Section 8 the results, including uncertainty,

$$\phi_X = \phi^I MCS$$

and all partial products of ϕ^I, M, C, and S are calculated. Dominant sequences are given for each result.

TABLE 1.4.1-1

INDIAN POINT 2 ROW VECTOR ϕ^I OF INTERNAL INITIATING EVENT FREQUENCIES (MEAN VALUE)
(Frequencies in Events Per Reactor Year

	1 Large LOCA	2 Medium LOCA	3 Small LOCA	4 Steam Generator Tube Rupture	5 Steam Break Inside Containment	6 Steam Break Outside Containment	7 Loss of Main Feedwater	8 Trip of One MSIV	9 Loss of RCS Flow	10 Core Power Excursion	11a Turbine Trip	11b Turbine Trip, Loss of Offsite Power	11c Turbine Trip, Loss of Service Water	12a Reactor Trip	12b Reactor Trip, Loss of Component Cooling	V Interfacing System LOCA
ϕ^I =	[1.95-3	1.95-3	1.85-2	2.74-2	1.95-3	1.95-3	6.70-0	1.25-0	1.36-1	2.21-2	7.32-0	1.82-1	1.95-3	6.84-0	1.95-3	4.58-7]

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11 x 10^{-5}.

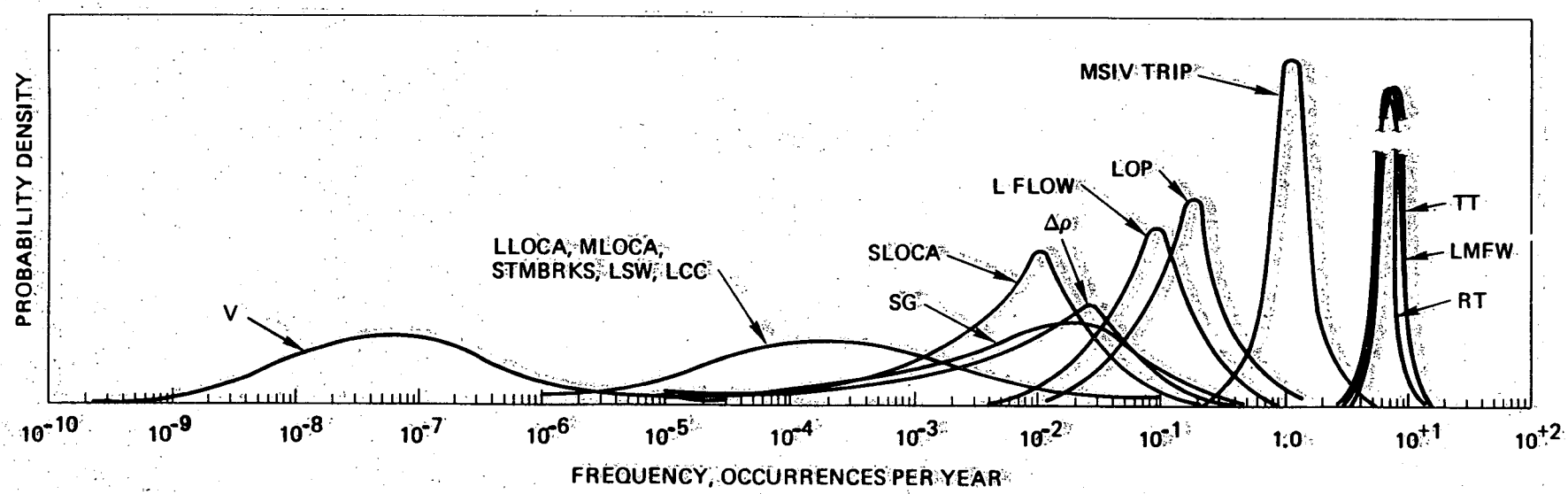

Figure 1.4.1-1. Probability of Frequency of Indian Point 2 Initiating Events

TABLE 1.4.1-2

INDIAN POINT 2 PLANT MATRIX M FOR INTERNAL INITIATING EVENTS (MEAN VALUE)[1]

Initiating Event	Plant Event Sequence Category[2]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	VE
1 Large LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	2.80-03	2.54-07	6.76-06	8.16-07	5.39-03	4.53-07	1.18-07	3.84-10	0
2 Medium LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	1.28-03	1.35-07	7.30-06	8.21-07	5.40-03	4.54-07	9.68-08	1.77-10	0
3 Small LOCA:	1.90-04	3.95-08	7.25-06	8.21-07	6.97-04	2.26-07	4.84-09	3.01-11	3.95-10	4.89-14	1.64-13	8.04-14	0	0	0	0	0	0	0	0	0
4 Steam Generator Tube Rupture:	1.65-11	1.35-15	2.71-13	2.88-12	6.62-13	5.64-17	1.04-11	5.48-12	3.31 06	1.65-09	1.05-06	8.21-07	0	0	0	0	0	0	0	0	0
5 Steam Break Inside Containment:	1.23-07	1.01-11	1.62-12	6.34-13	7.46-06	6.05-10	8.56-11	5.39-12	9.41-05	1.26-08	3.43-08	1.63-08	0	0	0	0	0	0	0	0	0
6 Steam Break Outside Containment:	1.23-07	1.01-11	1.62-12	6.34-13	7.46-06	6.05-10	8.56-11	5.39-12	9.41-05	1.26-08	3.43-08	1.63-08	0	0	0	0	0	0	0	0	0
7 Loss of Main Feedwater:	1.23-07	1.01-11	1.62-12	6.34-13	1.44-08	1.18-12	1.07-11	5.38-12	1.19-07	3.93-11	7.48-09	3.94-09	0	0	0	0	0	0	0	0	0
8 Trip of One MSIV:	0	0	0	0	9.47-09	7.67-13	4.49-13	3.64-17	1.19-07	3.93-11	7.48-09	3.94-09	0	0	0	0	0	0	0	0	0
9 Loss of RCS Flow:	1.11-07	9.09-12	1.45-12	5.69-13	1.29-08	1.06-12	9.67-12	4.84-12	1.07-07	3.54-11	6.74-09	3.55-09	0	0	0	0	0	0	0	0	0
10 Core Power Excursion	4.33-14	3.53-18	5.67-19	2.21-19	5.04-15	4.13-19	3.76-18	1.88-18	4.17-14	1.38-17	2.62-15	1.38-15	0	0	0	0	0	0	0	0	0
11a Turbine Trip:	1.23-07	1.01-11	1.62-12	2.81-12	1.44-08	1.18-12	1.07-11	5.38-12	1.19-07	3.93-11	7.48-09	3.94-09	0	0	0	0	0	0	0	0	0
11b Turbine Trip, Loss of Offsite Power:	1.79-04	1.61-08	2.18-05	5.56-06	8.57-07	3.70-10	3.77-10	1.32-12	9.56-07	2.27-09	8.12-09	1.97-09	0	0	0	0	0	0	0	0	0
11c Turbine Trip, Loss of Service Water:	0	0	1.24-7	2.57-10	0	0	2.88-5	2.33-9	0	0	1.16-7	1.82-6	0	0	0	0	0	0	0	0	0
12a Reactor Trip:	0	0	0	0	9.47-09	7.67-13	4.49-13	3.64-17	1.19-07	3.93-11	7.49-09	3.94-09	0	0	0	0	0	0	0	0	0
12b Reactor Trip, Loss of Component Cooling Water:	0	0	0	0	1.89-5	1.53-9	3.29-10	2.66-14	1.19-7	3.89-11	7.44-9	3.94-9	0	0	0	0	0	0	0	0	0
V Interfacing Systems LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.0

NOTES: 1. Mean values for conditional frequency of entering each plant event sequence category given that a specific initiating event has occurred

2. The plant event sequence categories are defined in Section 1.3.4.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior E - Early Melt F - Fan Coolers are operating
T - Transient behavior L - Late Melt C - Containment Sprays are operating

3. Values are presented in abbreviated scientific notation, e.g., 1.11-5 - 1.11 x 10^{-5}.

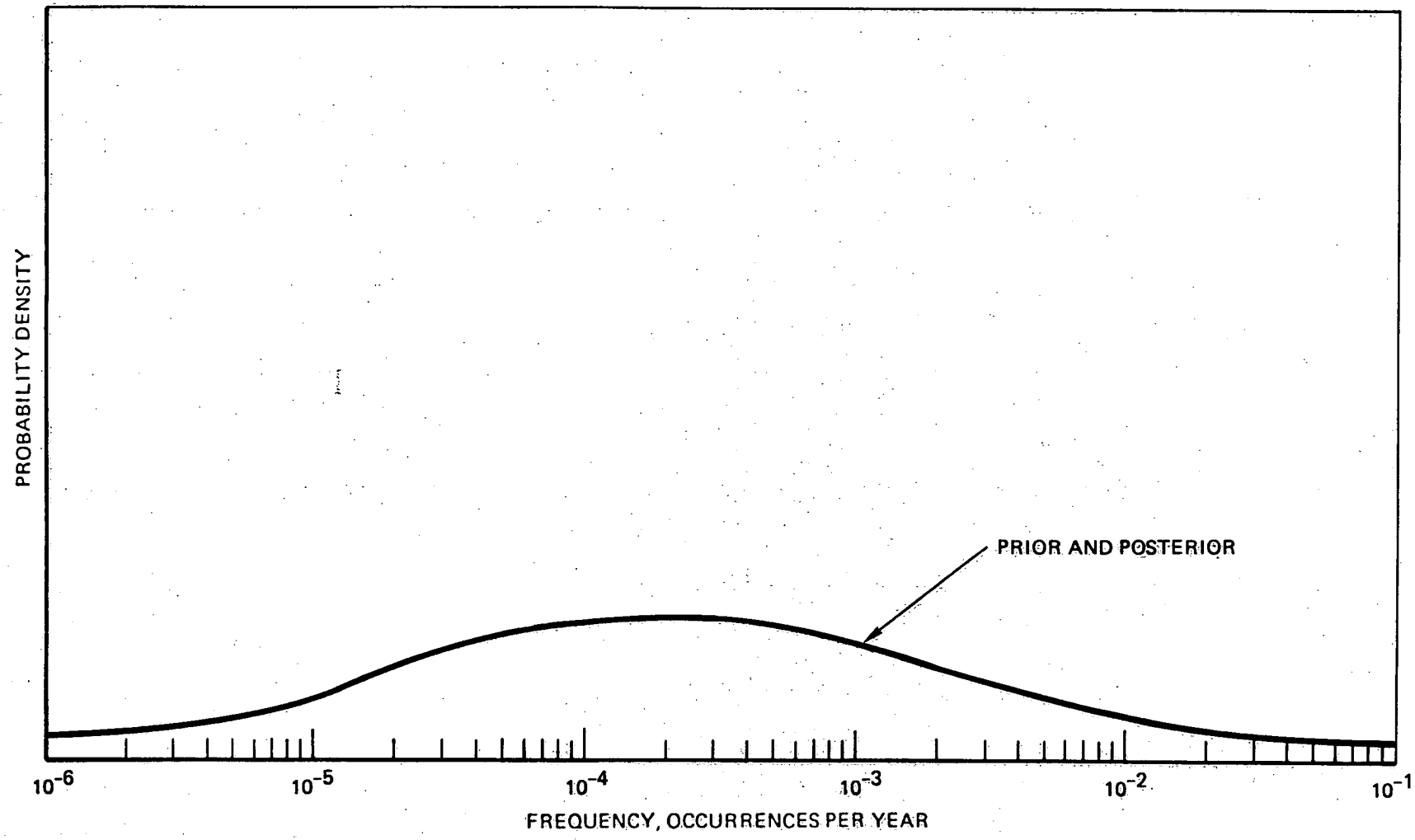

Figure 1.4.1-2. Probability Distribution for Frequency of Initiating Event 1 (Large LOCA)

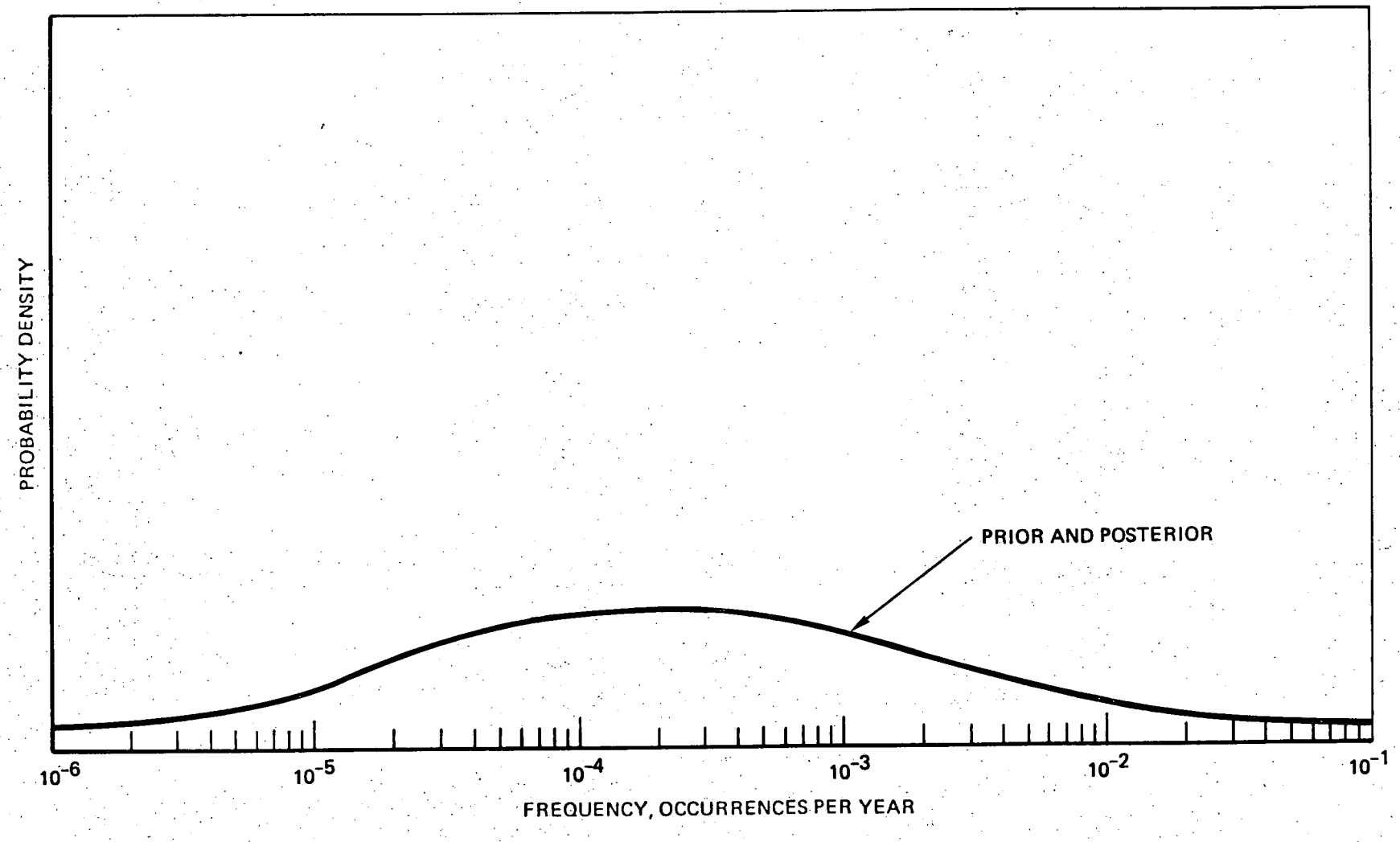

Figure 1.4.1-3. Probability Distribution for Frequency of Initiating Event 2 (Medium LOCA)

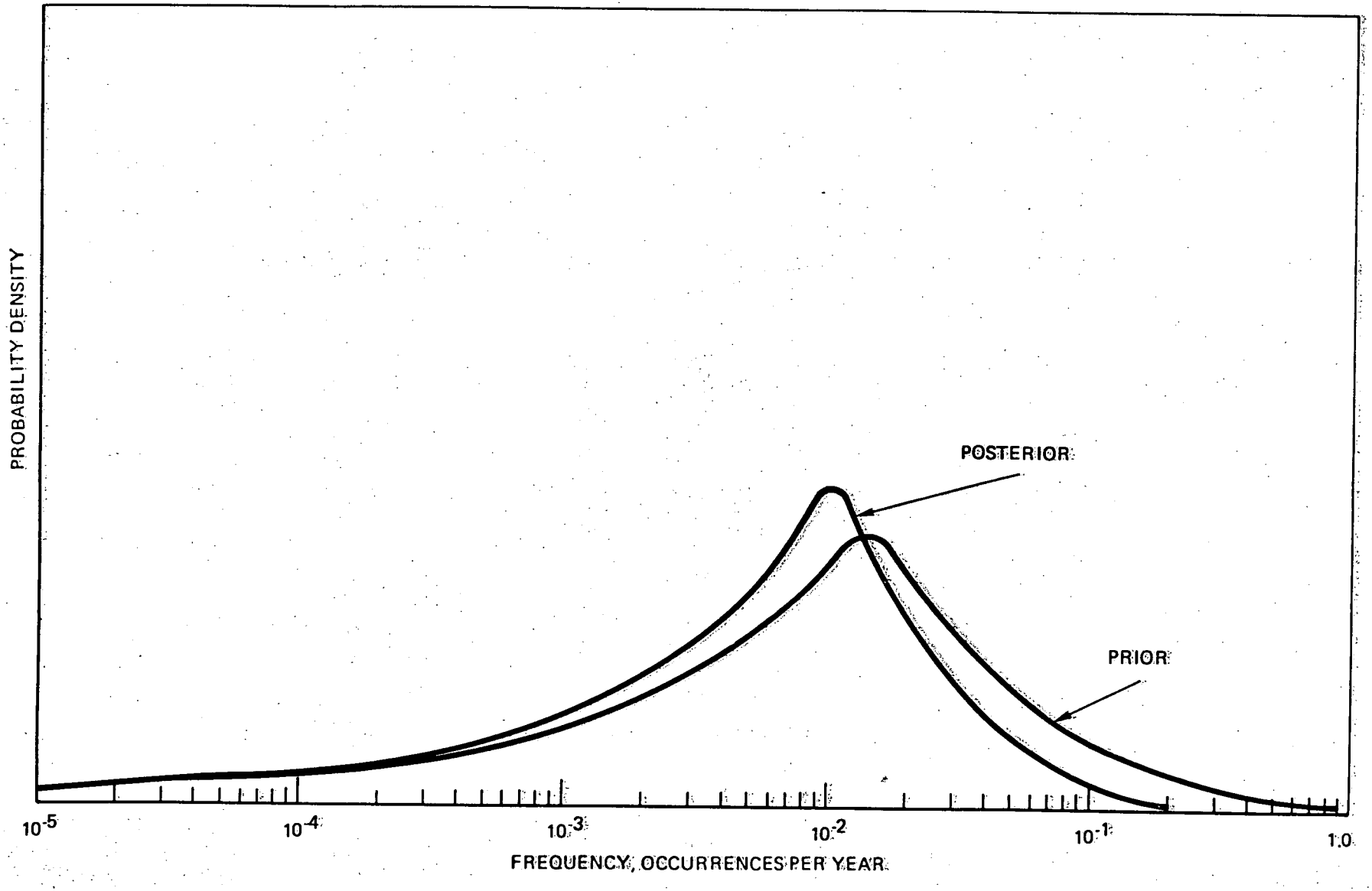

Figure 1.4.1-4. Probability Distribution for Frequency of Initiating Event 3 (Small LOCA)

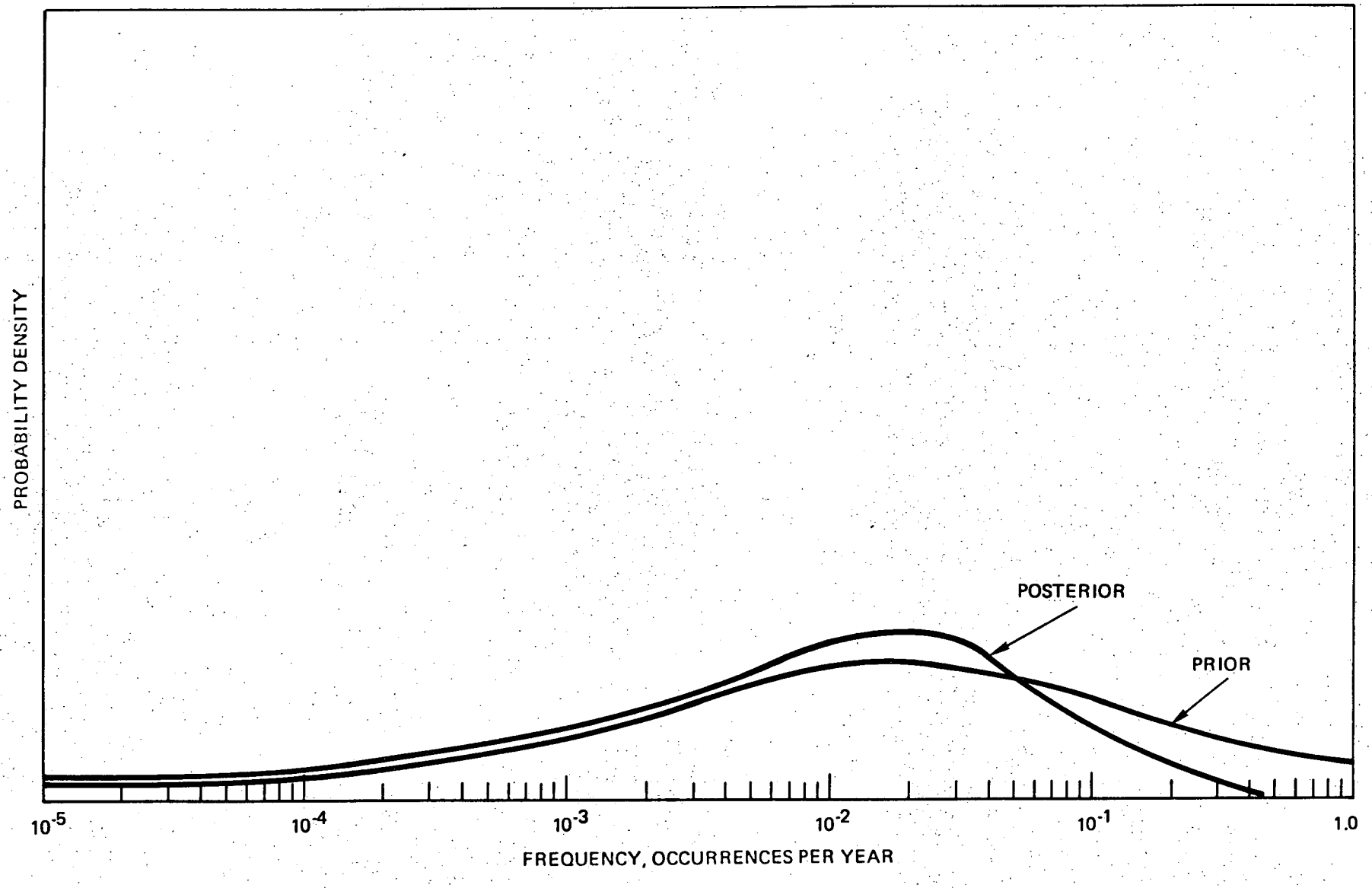

Figure 1.4.1-5. Probability Distribution for Frequency of Initiating Event 4 (Steam Generator Tube Rupture)

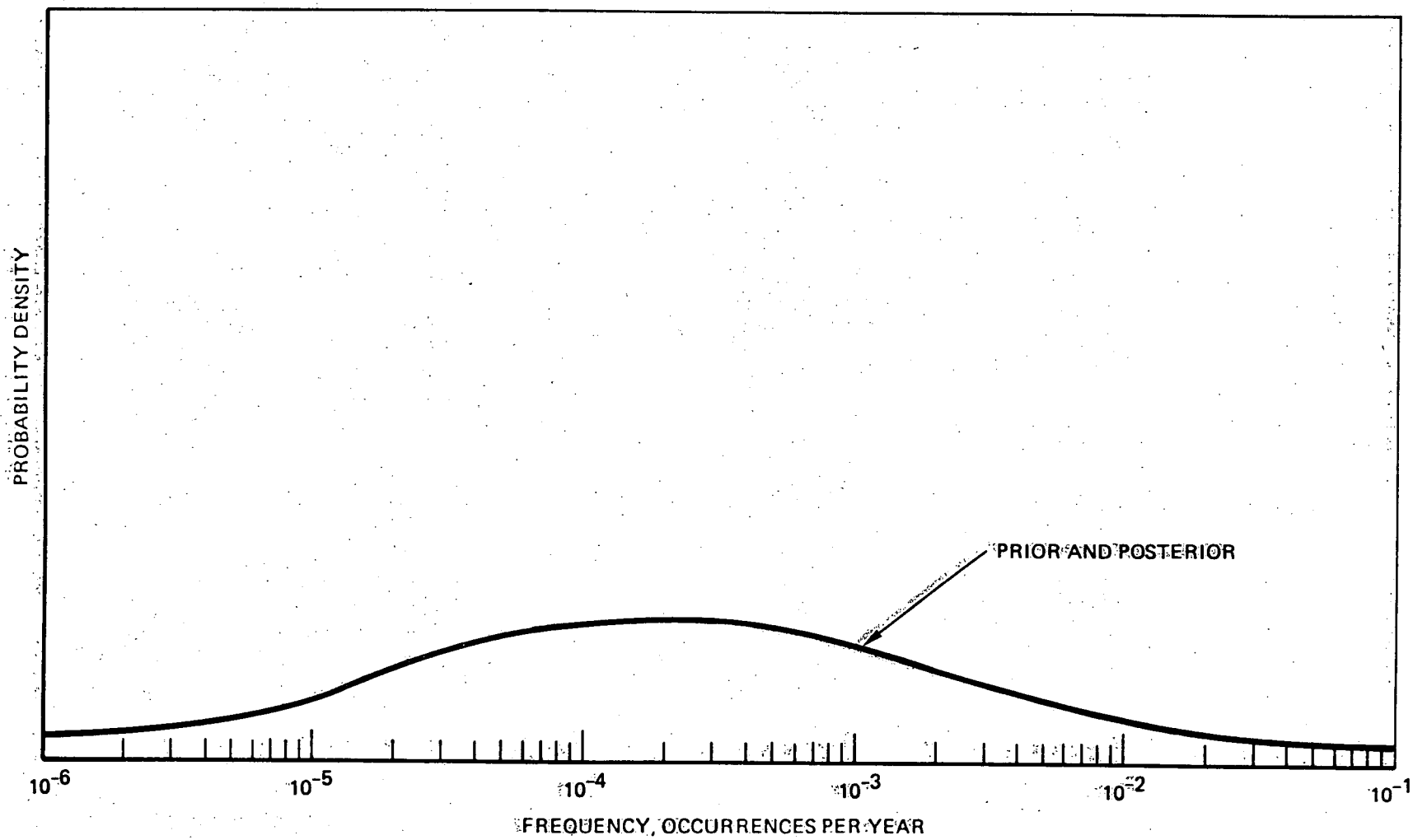

Figure 1.4.1-6. Probability Distribution for Frequency of Initiating Event 5 (Steam Break Inside Containment)

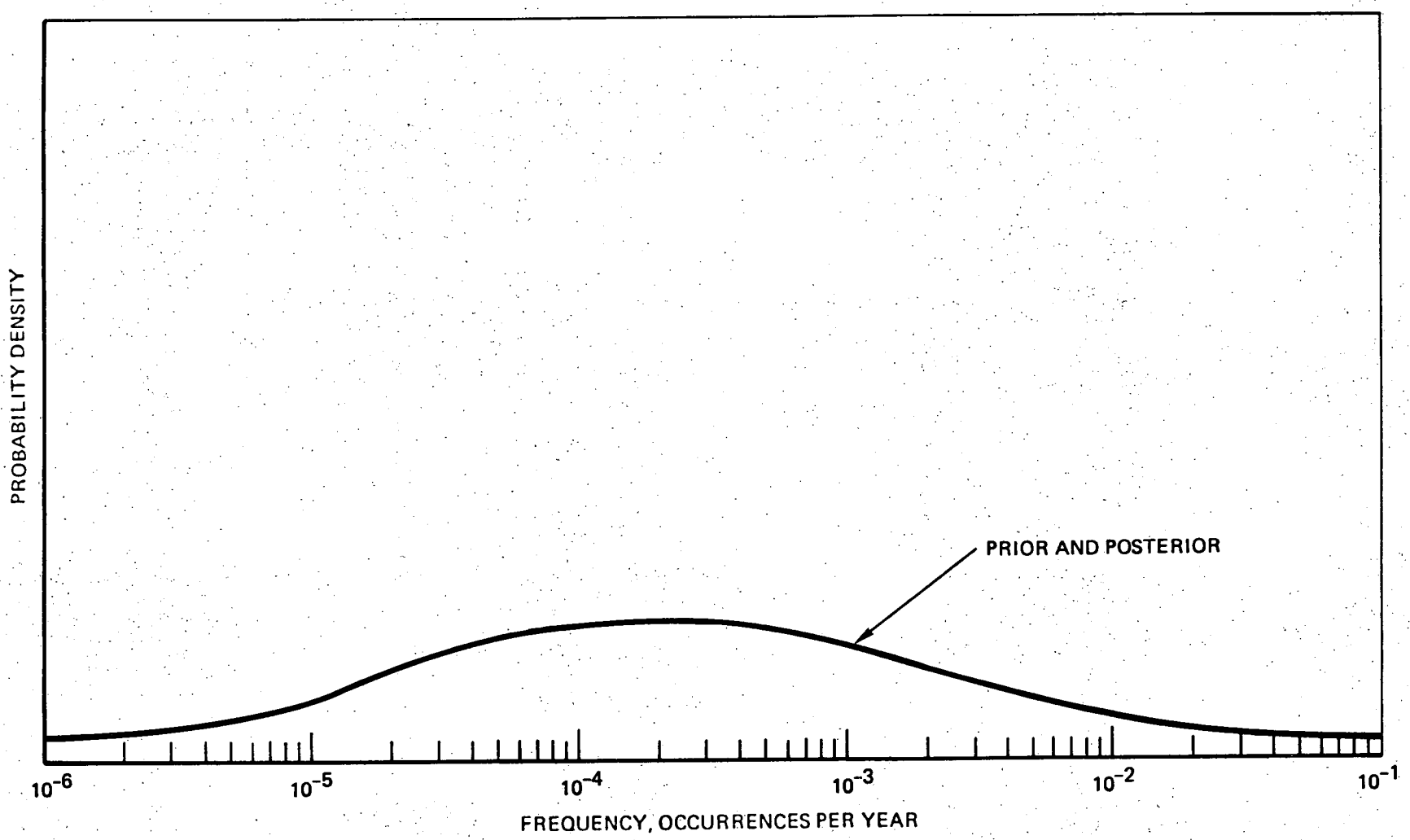

Figure 1.4.1-7. Probability Distribution for Frequency of Initiating Event 6 (Steam Break Outside Containment)

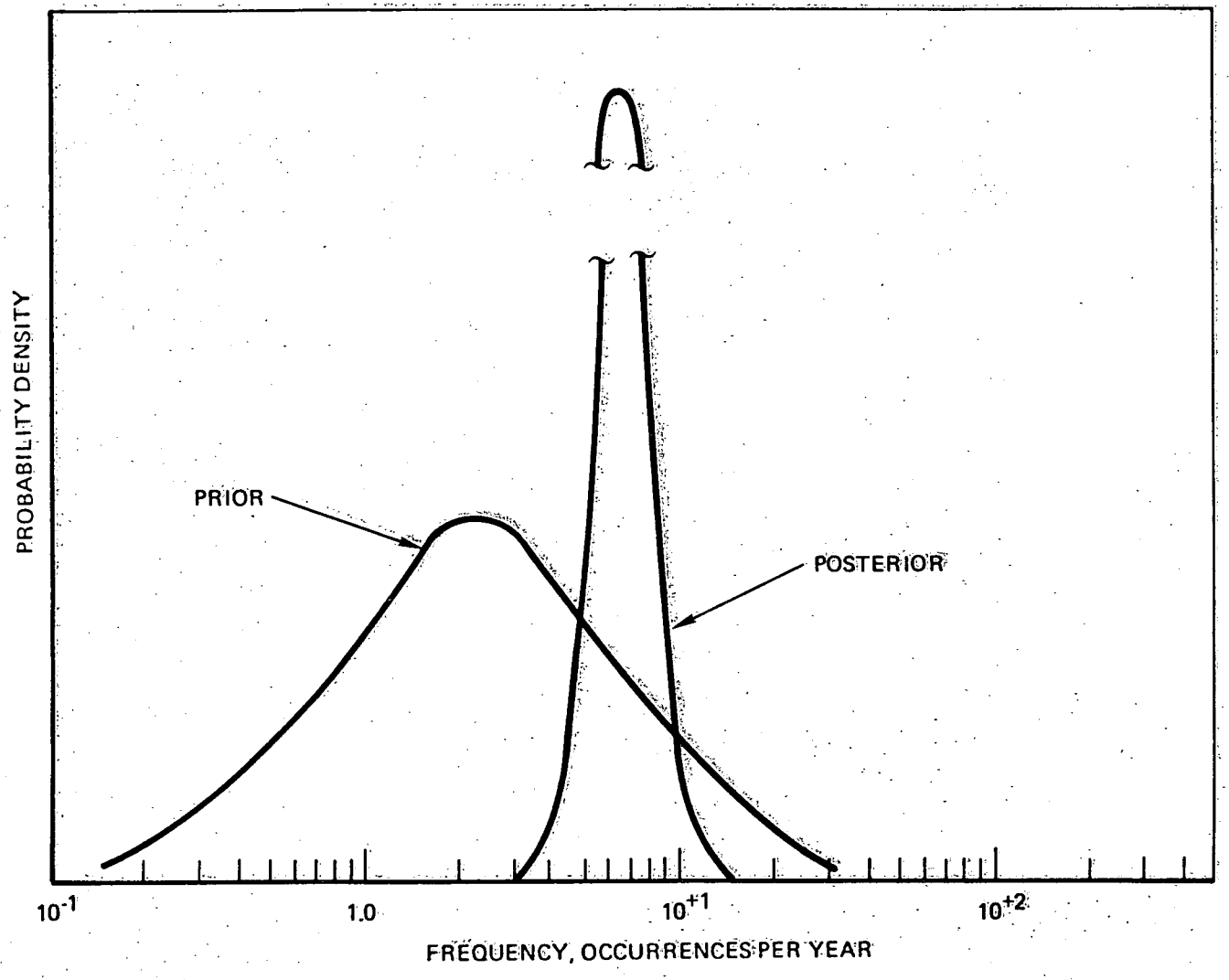

Figure 1.4.1-8. Probability Distribution for Frequency of Initiating Event 7 (Loss of Main Feedwater)

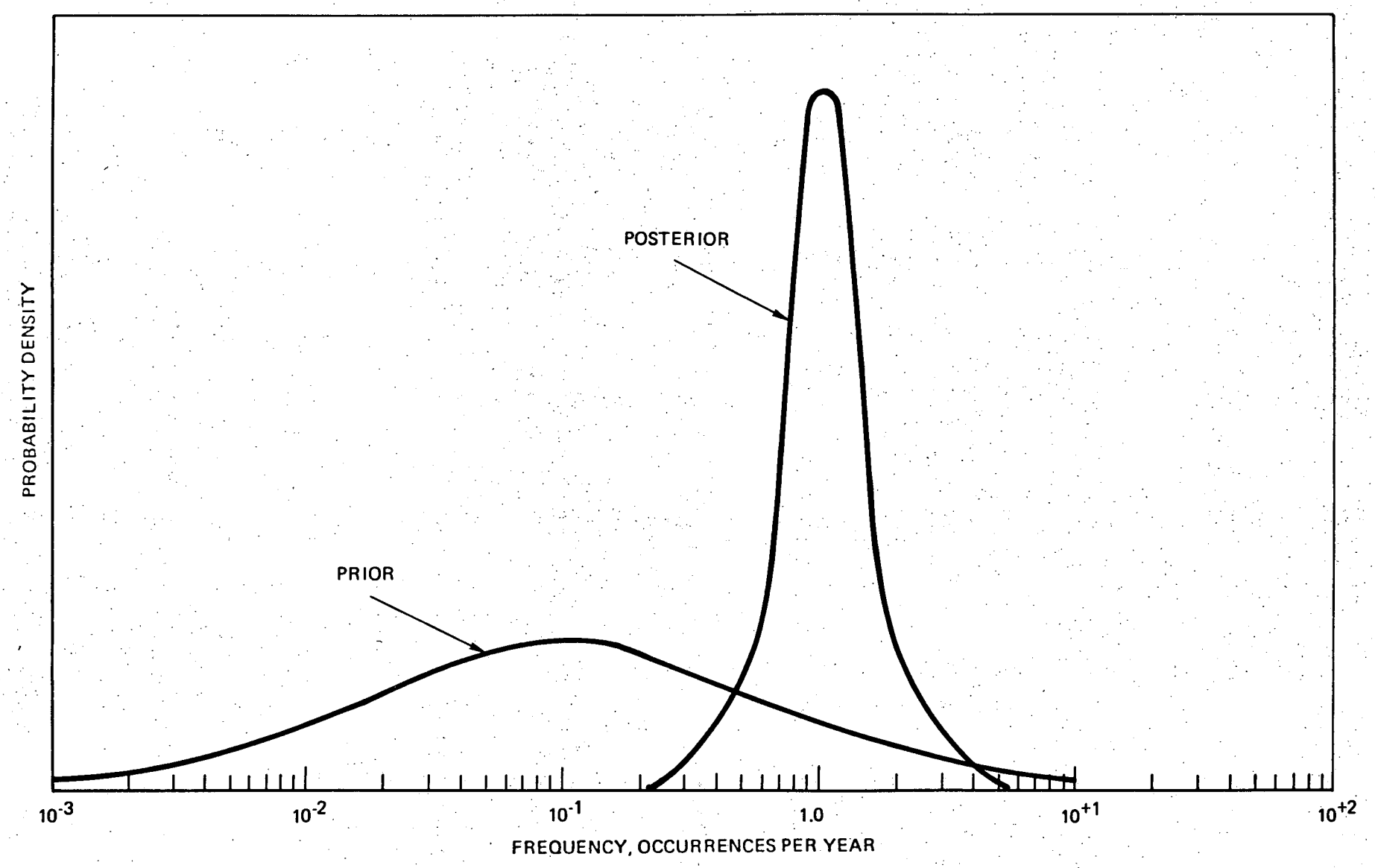

Figure 1.4.1-9. Probability Distribution for Frequency of Initiating Event 8 (Trip of One MSIV)

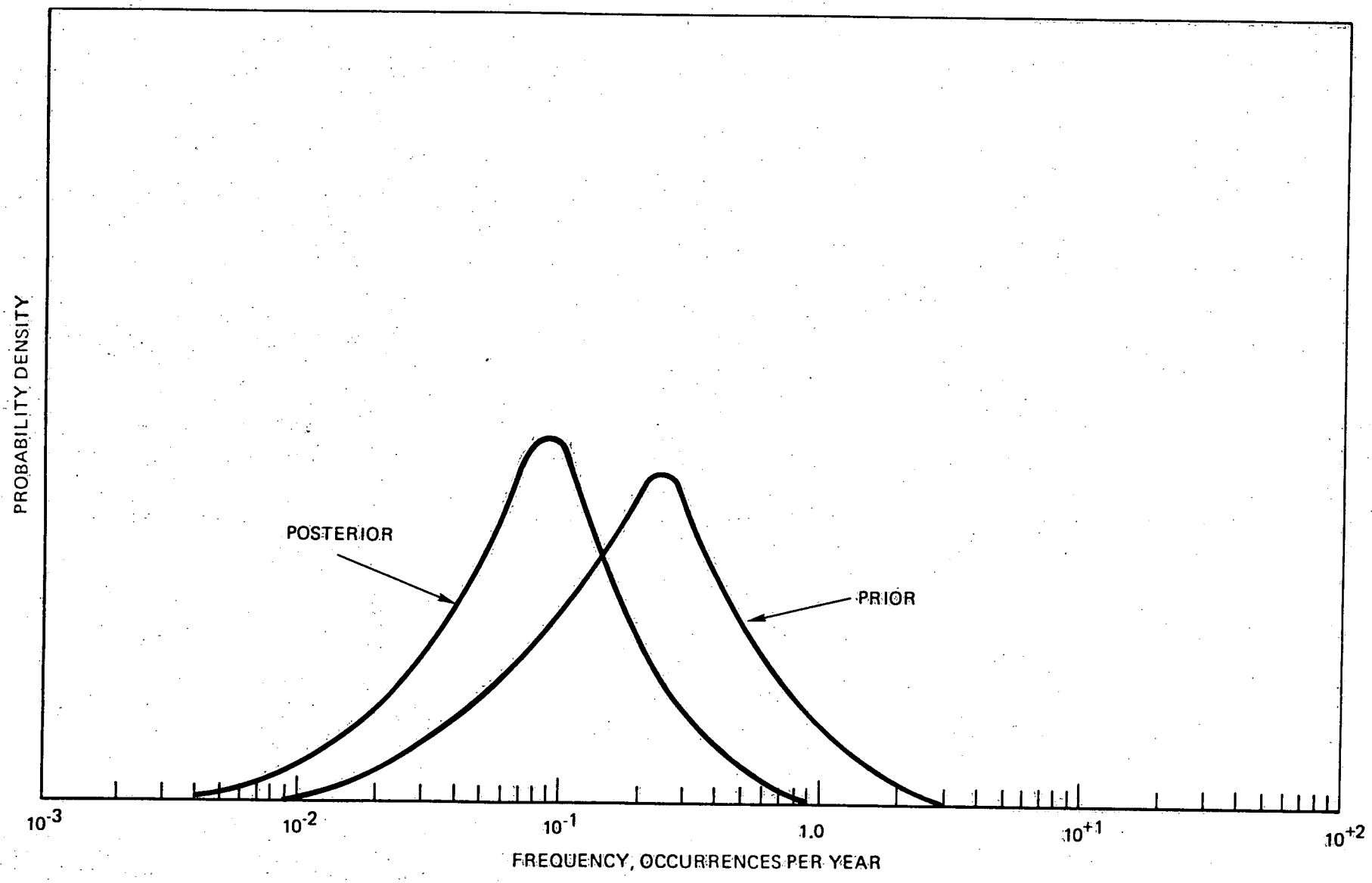

Figure 1.4.1-10. Probability Distribution for Frequency of Initiating Event 9 (Loss of RCS Flow)

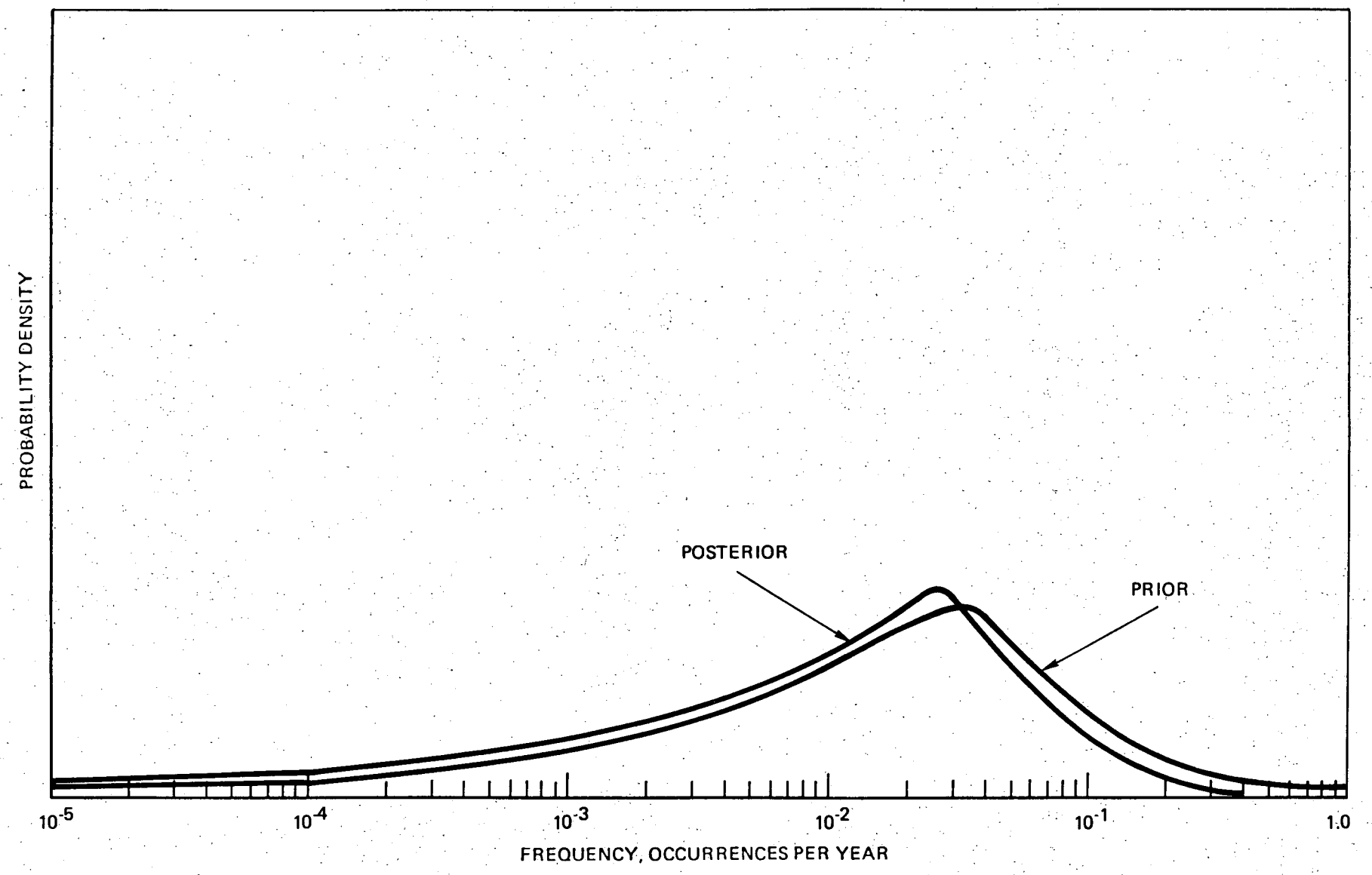

Figure 1.4.1-11. Probability Distribution for Frequency of Initiating Event 10 (Core Power Excursion)

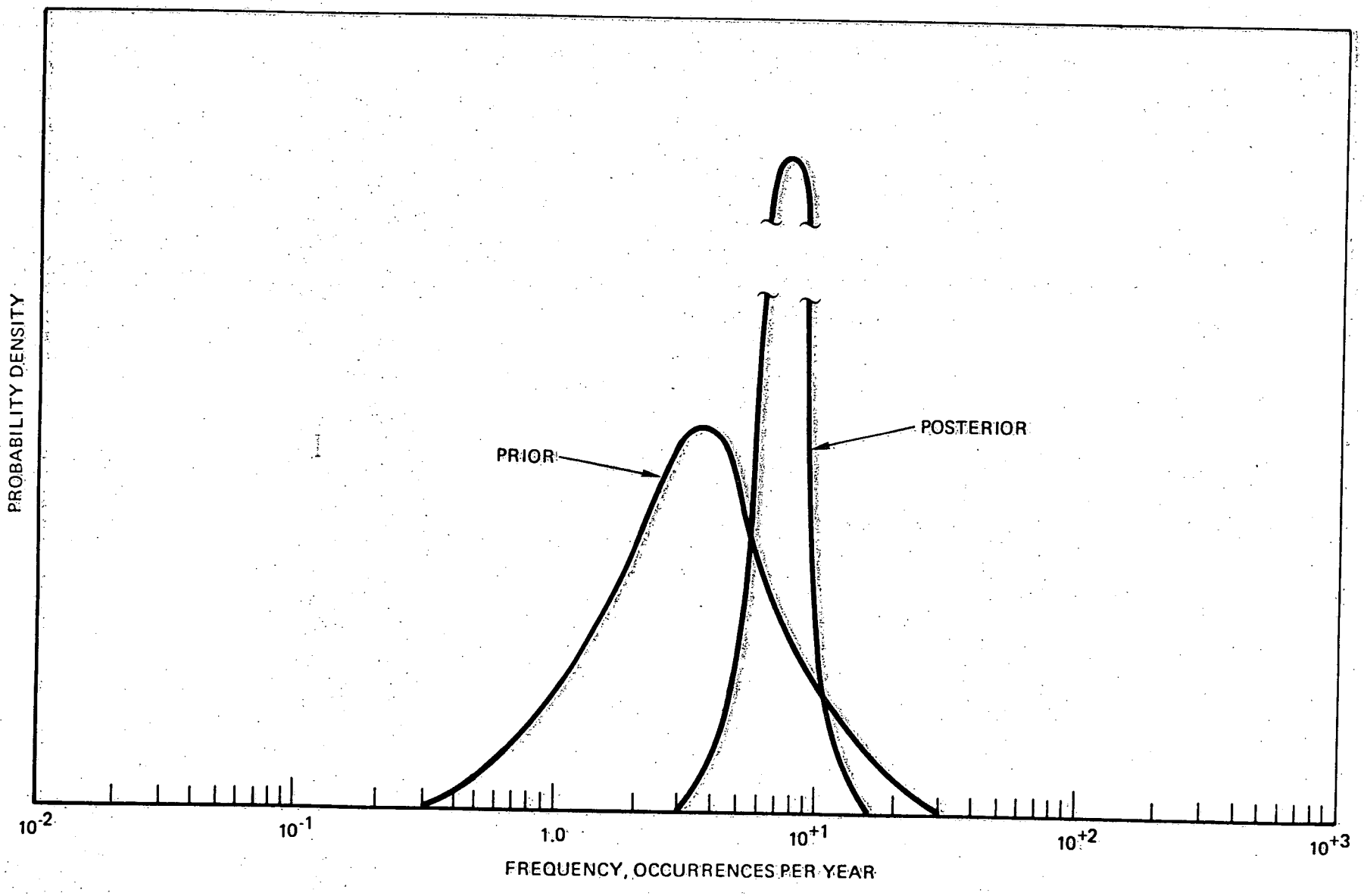

Figure 1.4.1-12. Probability Distribution for Frequency of Initiating Event 11a (Turbine Trip)

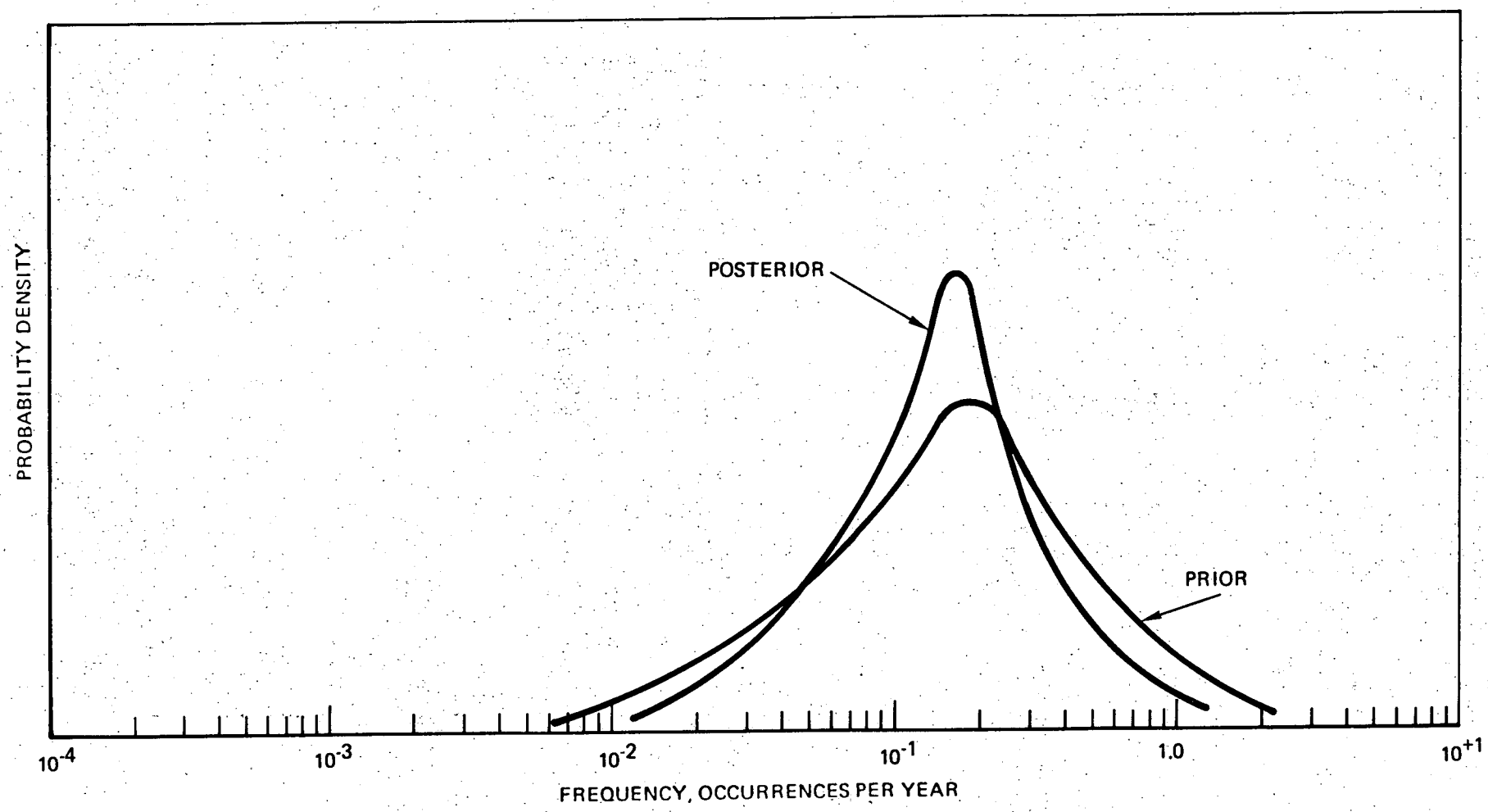

Figure 1.4.1-13. Probability Distribution for Frequency of Initiating Event 11b (Turbine Trip, Loss of Offsite Power)

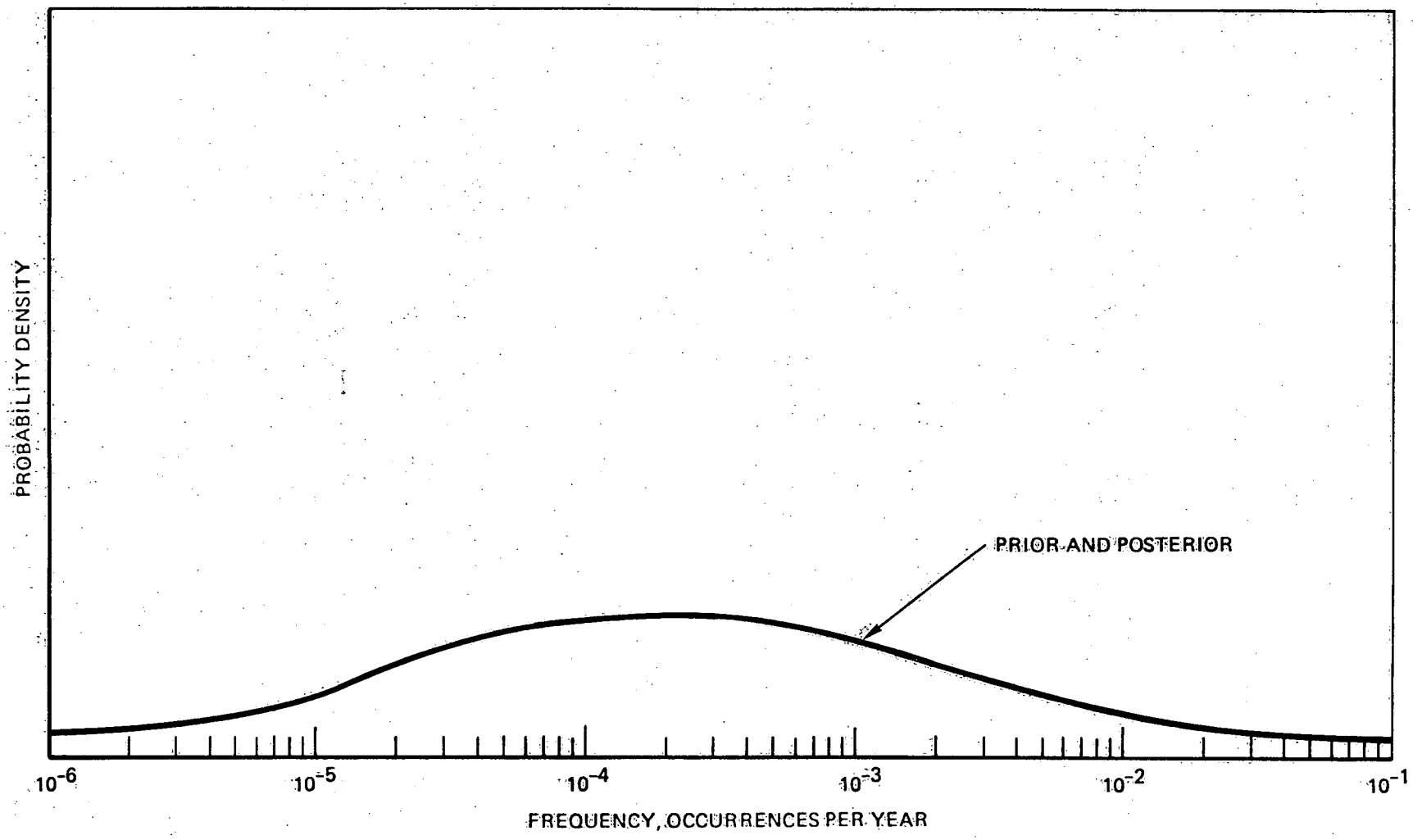

Figure 1.4.1-14. Probability Distribution for Frequency of Initiating Event 11c (Turbine Trip, Loss of Service Water)

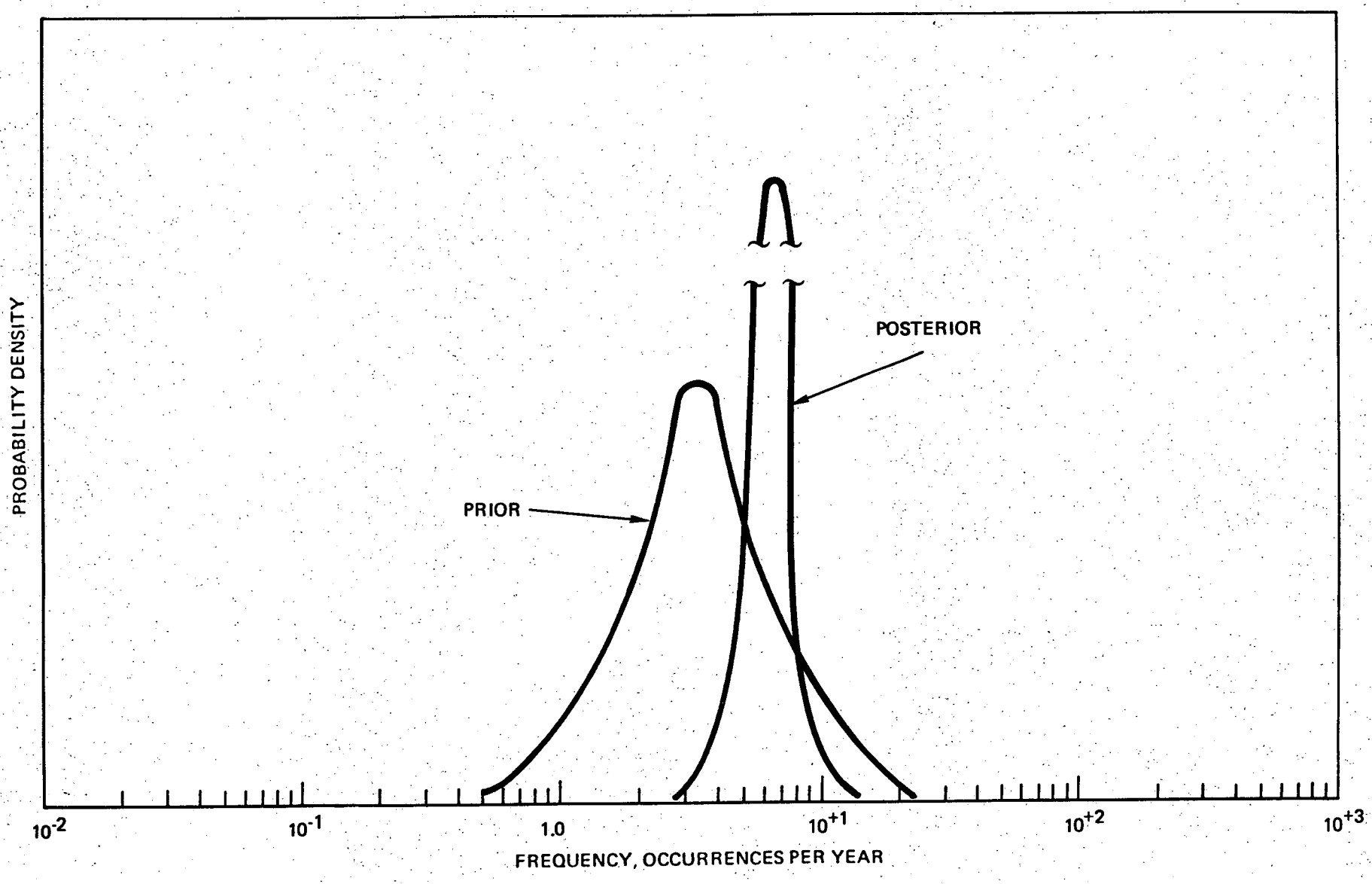

Figure 1.4.1-15. Probability Distribution for Frequency of Initiating Event 12a (Reactor Trip)

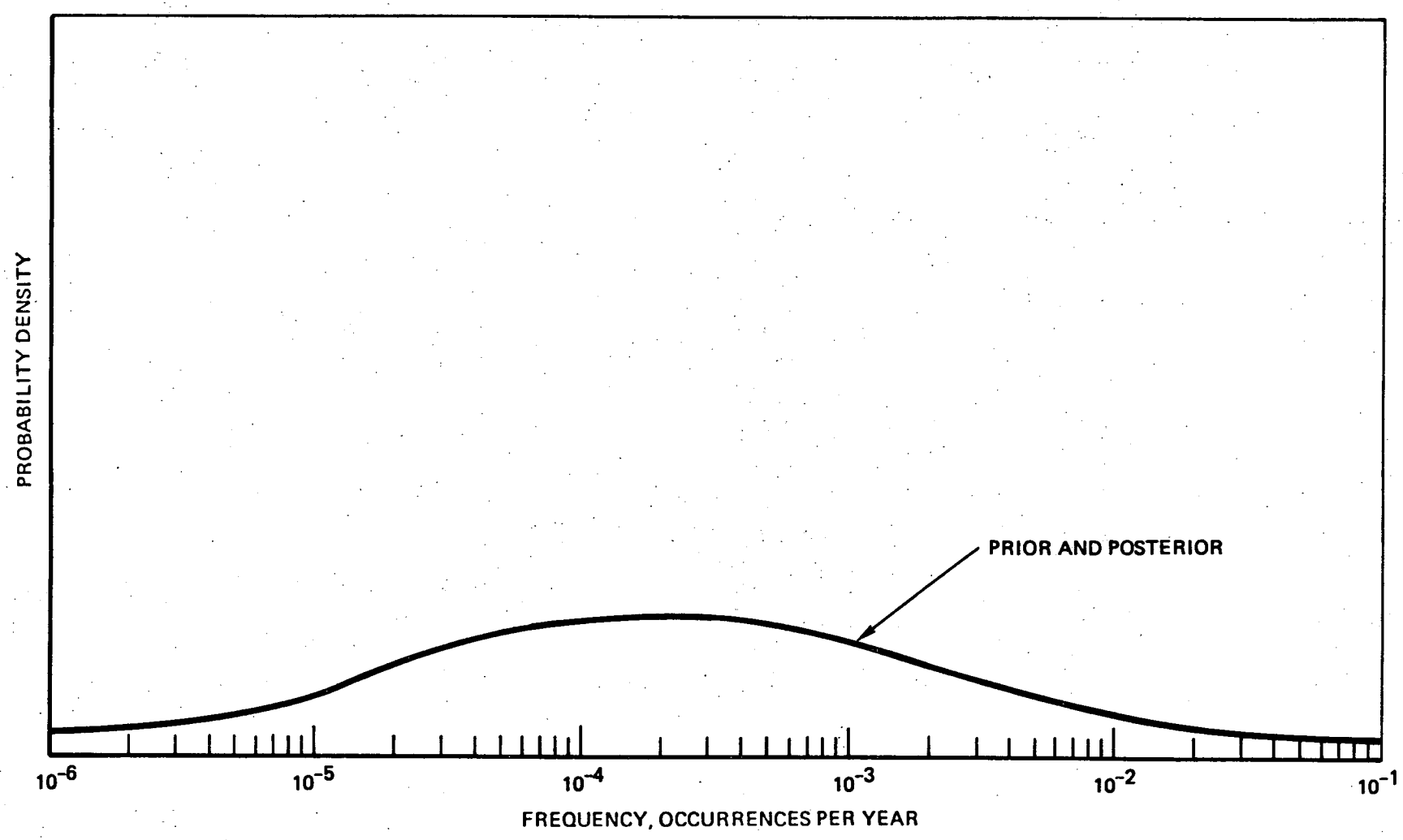

Figure 1.4.1-16. Probability Distribution for Frequency of Initiating Event 12b (Reactor Trip, Loss of Component Cooling)

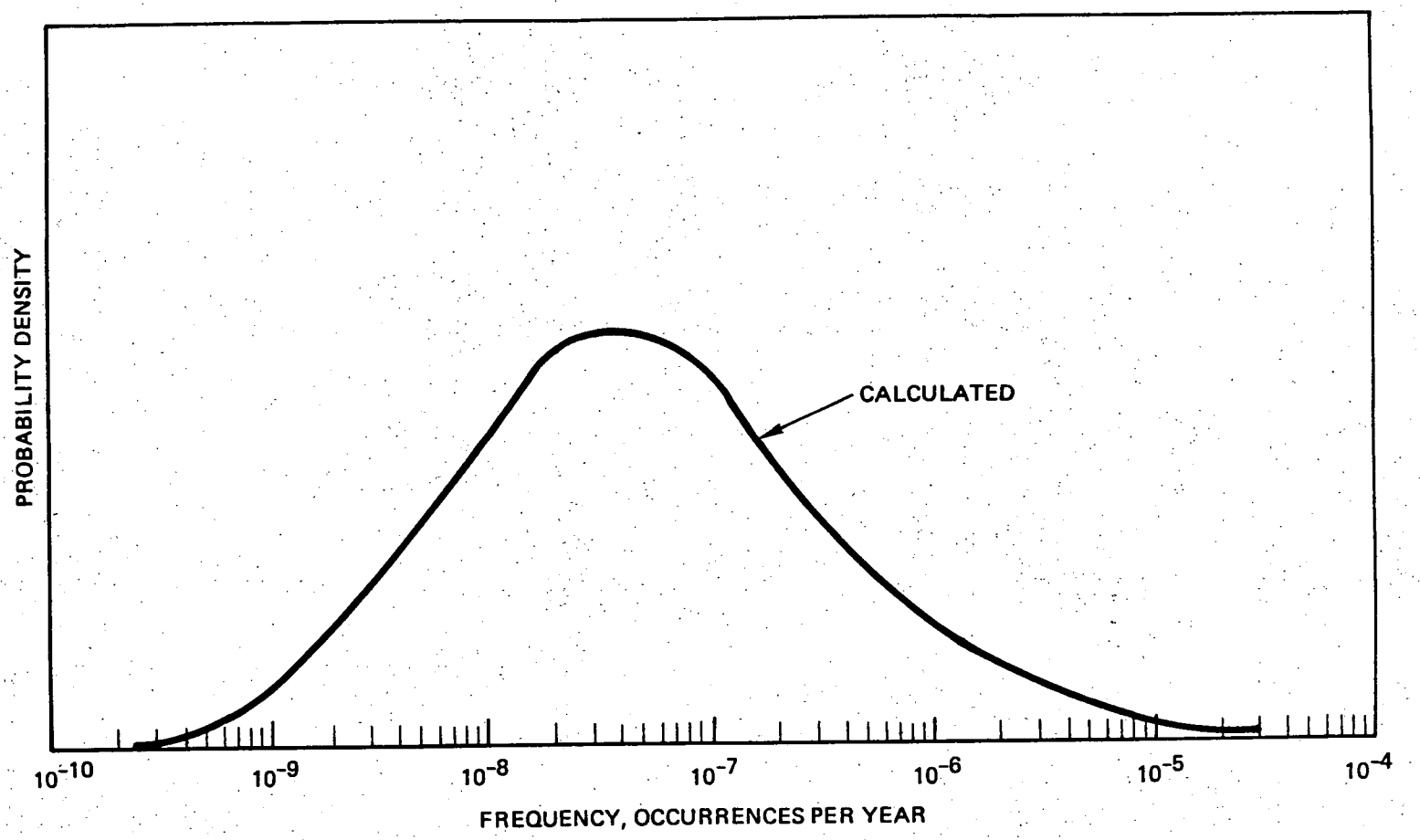

Figure 1.4.1-17. Probability Distribution for Frequency of Initiating Event V (Interfacing System LOCA)

TABLE 1.4.2-1

INDIAN POINT 3 ROW VECTOR ϕ^I OF INTERNAL INITIATING EVENT FREQUENCIES (MEAN VALUE)
(Frequencies in Events Per Reactor Year)

	1 Large LOCA	2 Medium LOCA	3 Small LOCA	4 Steam Generator Tube Rupture	5 Steam Break Inside Contain-ment	6 Steam Break Outside Contain-ment	7 Loss of Main Feedwater	8 Trip of One MSIV	9 Loss of RCS Flow	10 Core Power Excursion	11a Turbine Trip	11b Turbine Trip, Loss of Offsite Power	11c Turbine Trip, Loss of Service Water	12a Reactor Trip	12b Reactor Trip, Loss of Component Cooling	V Inter-facing System LOCA
ϕ^I =	[2.16-3	2.16-3	2.01-2	3.37-2	2.16-3	2.16-3	3.80-0	8.98-2	1.71-1	2.57-2	2.72-0	2.66-1	2.16-3	2.86-0	2.16-3	4.64-7]

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11 x 10^{-5}.

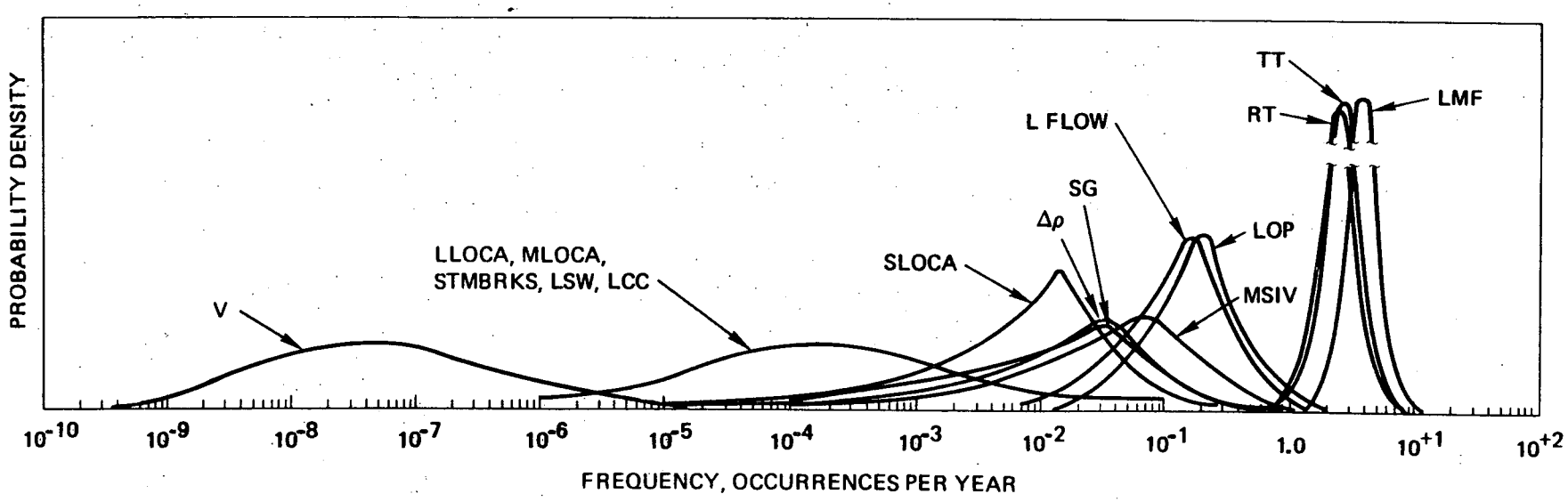

Figure 1.4.2-1. Probability of Frequency of Indian Point 3 Initiating Events

TABLE 1.4.2-2

INDIAN POINT 3 MATRIX M FOR INTERNAL INTIATING EVENTS (MEAN VALUE)[1]

Initiating Event	Plant Event Sequence Category[2]																				
	SEFC	SEF	SEC	SE	SLFC	SLF	SLC	SL	TEFC	TEF	TEC	TE	AEFC	AEF	AEC	AE	ALFC	ALF	ALC	AL	VE
1 Large LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	3.01-03	1.33-07	7.19-06	1.26-07	5.34-03	1.97-07	1.87-07	3.78-07	0
2 Medium LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	1.00-03	6.10-08	7.62-06	5.06-07	5.35-03	1.97-07	1.68-07	1.23-11	0
3 Small LOCA:	1.40-04	2.91-08	6.22-06	4.77-09	4.11-03	1.49-07	3.73-08	1.22-11	8.70-10	4.13-13	5.00-13	8.75-14	0	0	0	0	0	0	0	0	0
4 Steam Generator Tube Rupture:	4.39-11	1.58-15	6.58-13	6.05-14	1.20-11	4.37-16	2.66-11	2.42-12	1.88-05	1.38-09	1.39-06	5.06-07	0	0	0	0	0	0	0	0	0
5 Steam Break Inside Containment:	2.88-07	1.04-11	9.82-12	1.90-13	6.17-06	2.22-09	2.94-09	7.97-12	6.88-05	4.00-09	4.48-08	9.61-09	0	0	0	0	0	0	0	0	0
6 Steam Break Outside Containment:	2.88-07	1.04-11	9.82-12	1.90-13	6.17-05	2.22-09	2.94-09	7.97-12	6.88-05	4.00-09	4.48-08	9.61-09	0	0	0	0	0	0	0	0	0
7 Loss of Main Feedwater:	2.88-07	1.04-11	9.82-12	2.34-13	1.42-07	5.14-12	5.02-11	9.65-12	7.18-08	9.01-12	1.57-10	1.86-11	0	0	0	0	0	0	0	0	0
8 Trip of One MSIV:	0	0	0	0	6.30-08	2.27-12	2.02-11	7.27-16	7.00-08	8.94-12	1.54-08	2.02-09	0	0	0	0	0	0	0	0	0
9 Loss of RCS Flow:	2.59-07	9.39-12	8.85-12	1.71-13	1.28-07	4.62-12	4.53-11	7.07-12	6.38-08	8.08-12	1.38-08	1.82-09	0	0	0	0	0	0	0	0	0
10 Core Power Excursion:	1.01-13	3.66-18	3.44-18	6.67-20	4.98-14	1.80-18	1.76-17	2.75-18	2.47-14	3.13-18	5.37-15	7.08-16	0	0	0	0	0	0	0	0	0
11a Turbine Trip:	2.88-07	1.04-11	9.82-12	2.34-13	1.42-07	5.13-12	5.02-11	9.65-12	7.16-08	9.00-12	1.57-10	1.86-11	0	0	0	0	0	0	0	0	0
11b Turbine Trip, Loss of Offsite Power:	1.17-05	1.36-09	3.51-08	2.36-06	4.28-07	3.40-11	3.77-11	2.75-14	1.21-06	1.09-09	8.50-09	4.05-09	0	0	0	0	0	0	0	0	0
11c Turbine Trip, Loss of Service Water:	0	0	2.88-7	1.79-10	0	0	3.42-5	7.97-9	0	0	6.83-8	2.40-5	0	0	0	0	0	0	0	0	0
12a Reactor Trip:	0	0	0	0	6.64-08	2.27-12	2.02-11	7.27-16	7.09-08	8.97-12	1.56-10	1.86-11	0	0	0	0	0	0	0	0	0
12b Reactor Trip - Loss of Component Cooling Water:	0	0	0	0	1.51-5	5.45-10	2.89-9	1.04-13	7.00-8	8.96-12	1.54-8	2.02-9	0	0	0	0	0	0	0	0	0
V Interfacing Systems LOCA:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1

NOTES: 1. Mean values for conditional frequency of entering each Plant Event Sequence Category given that a specific initiating event has occurred

2. The Plant Event Sequence Categories are defined in Section 1.3.6.0, briefly:

A - Large LOCA behavior
S - Small LOCA behavior E - Early Melt F - Fan Coolers are operating
T - Transient behavior L - Late Melt C - Containment Sprays are operating

3. Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

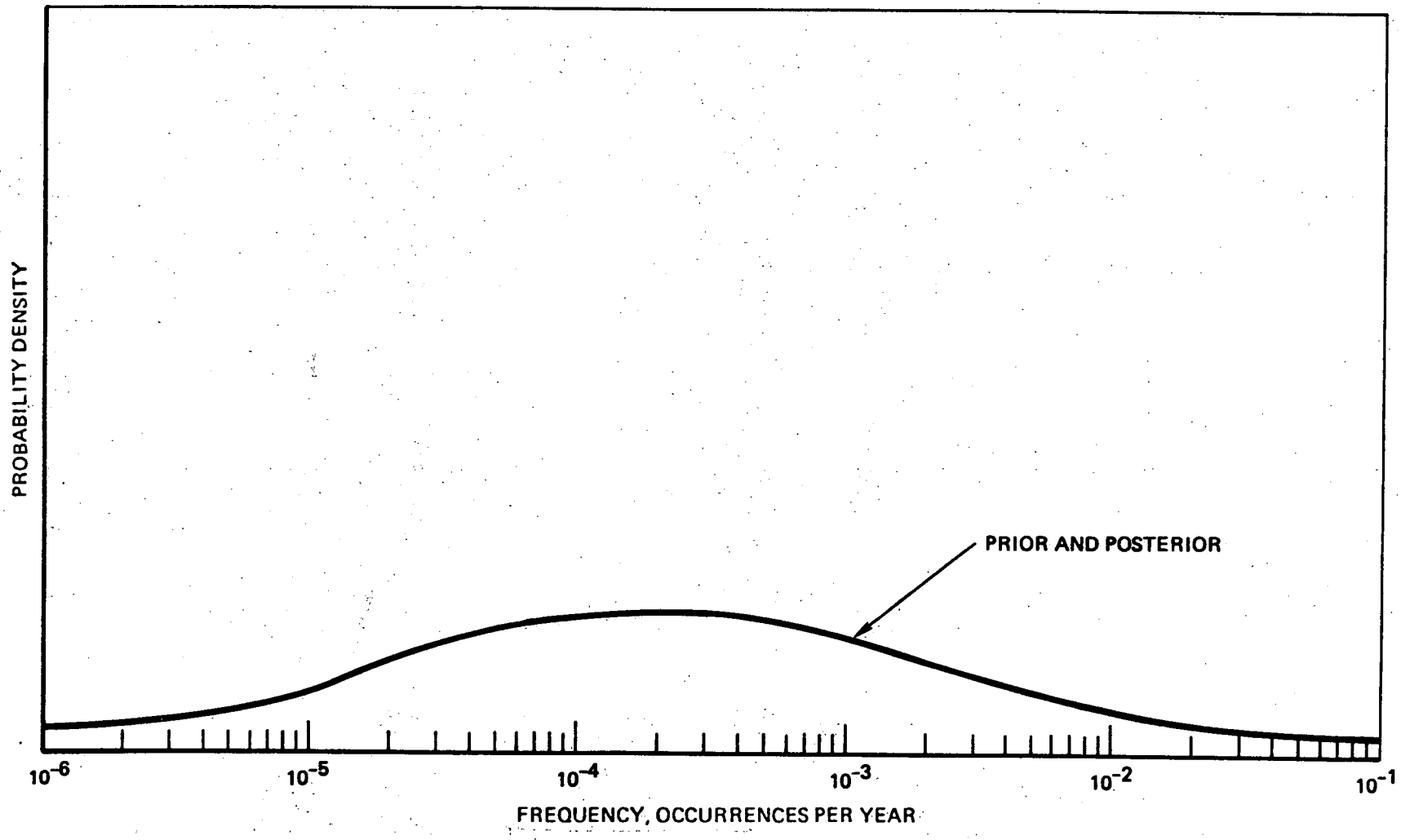

Figure 1.4.2-2. Probability Distribution for Frequency of Initiating Event 1 (Large LOCA)

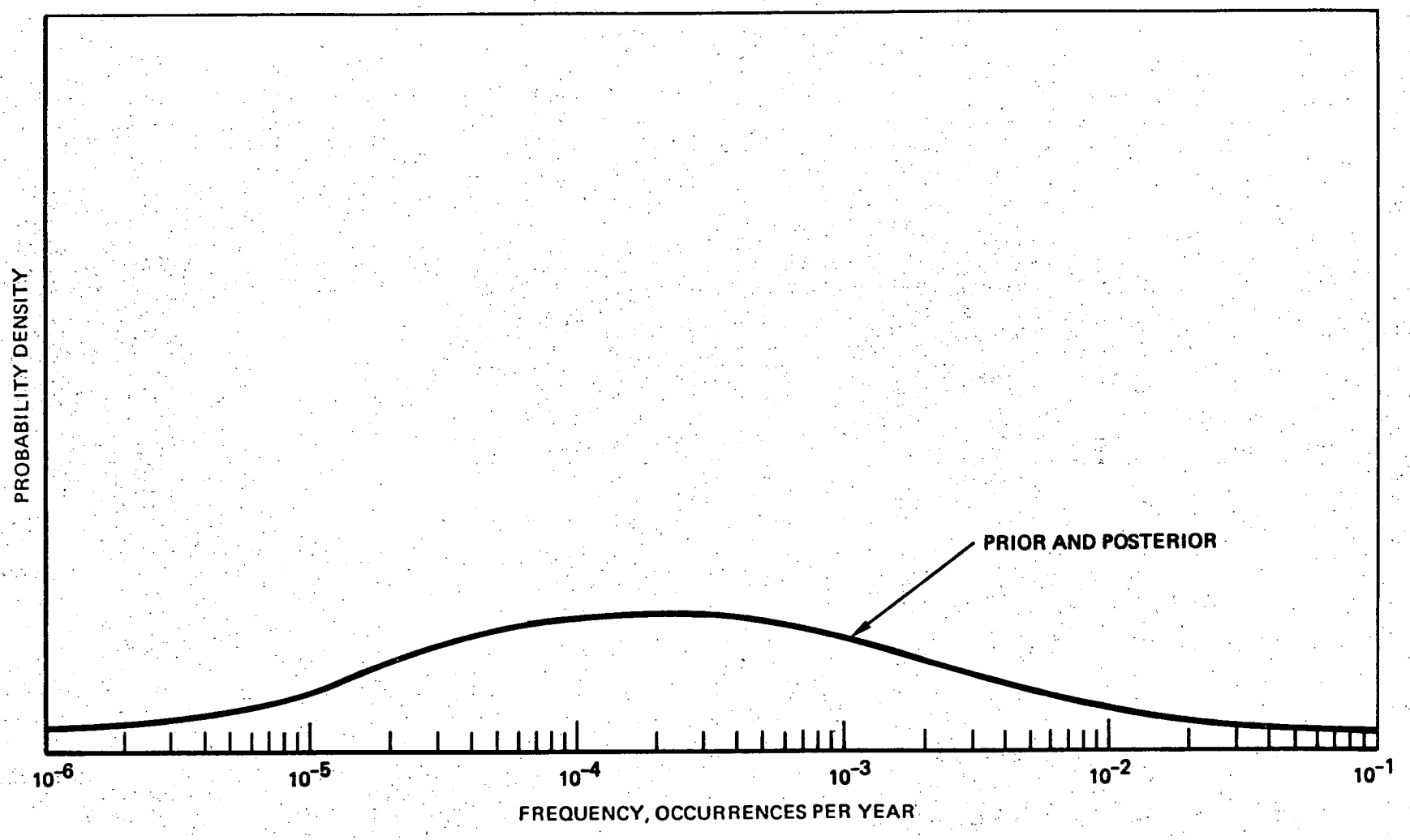

Figure 1.4.2-3. Probability Distribution for Frequency of Initiating Event 2 (Medium LOCA)

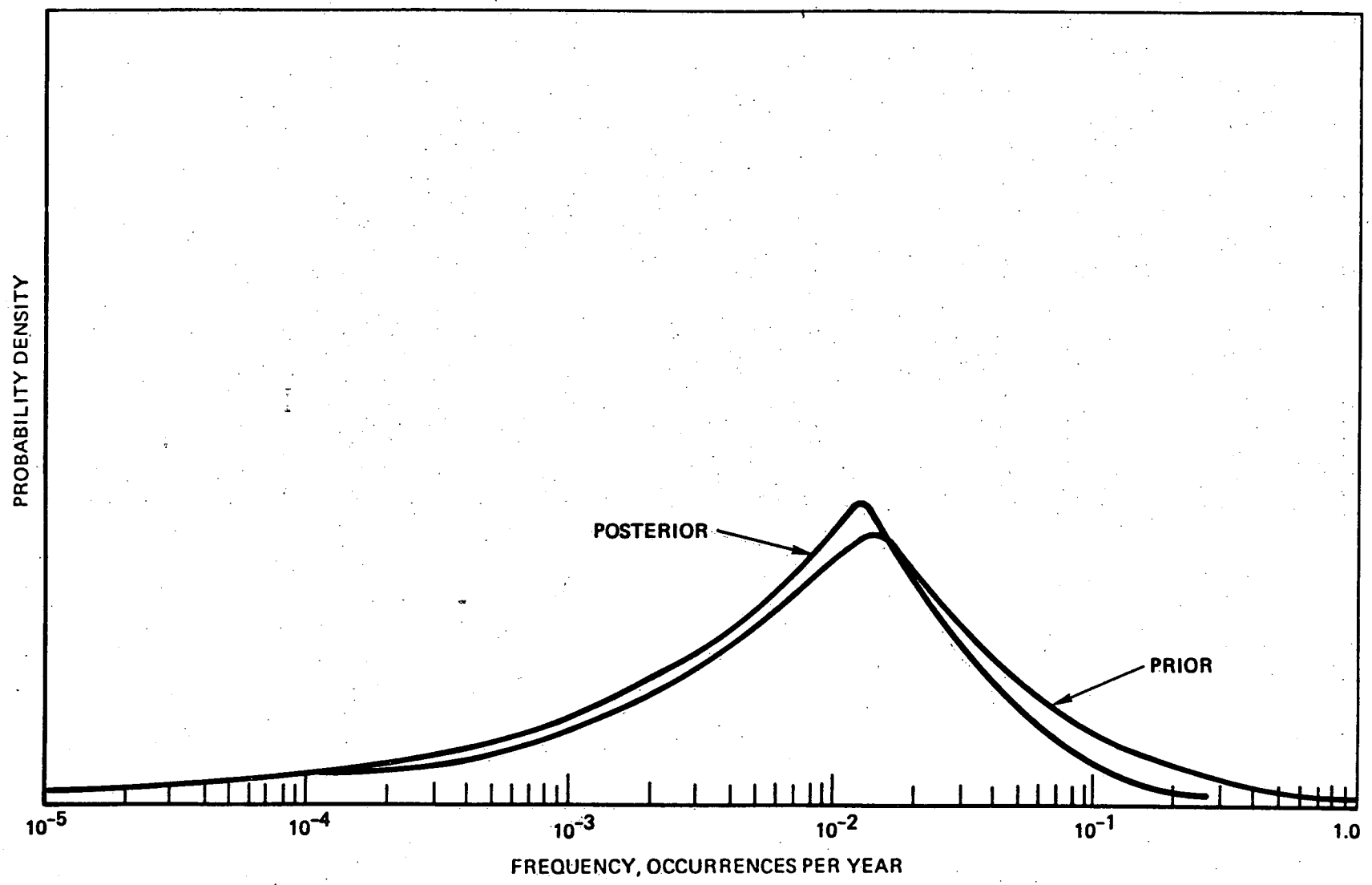

Figure 1.4.2-4. Probability Distribution for Frequency of Initiating Event 3 (Small LOCA)

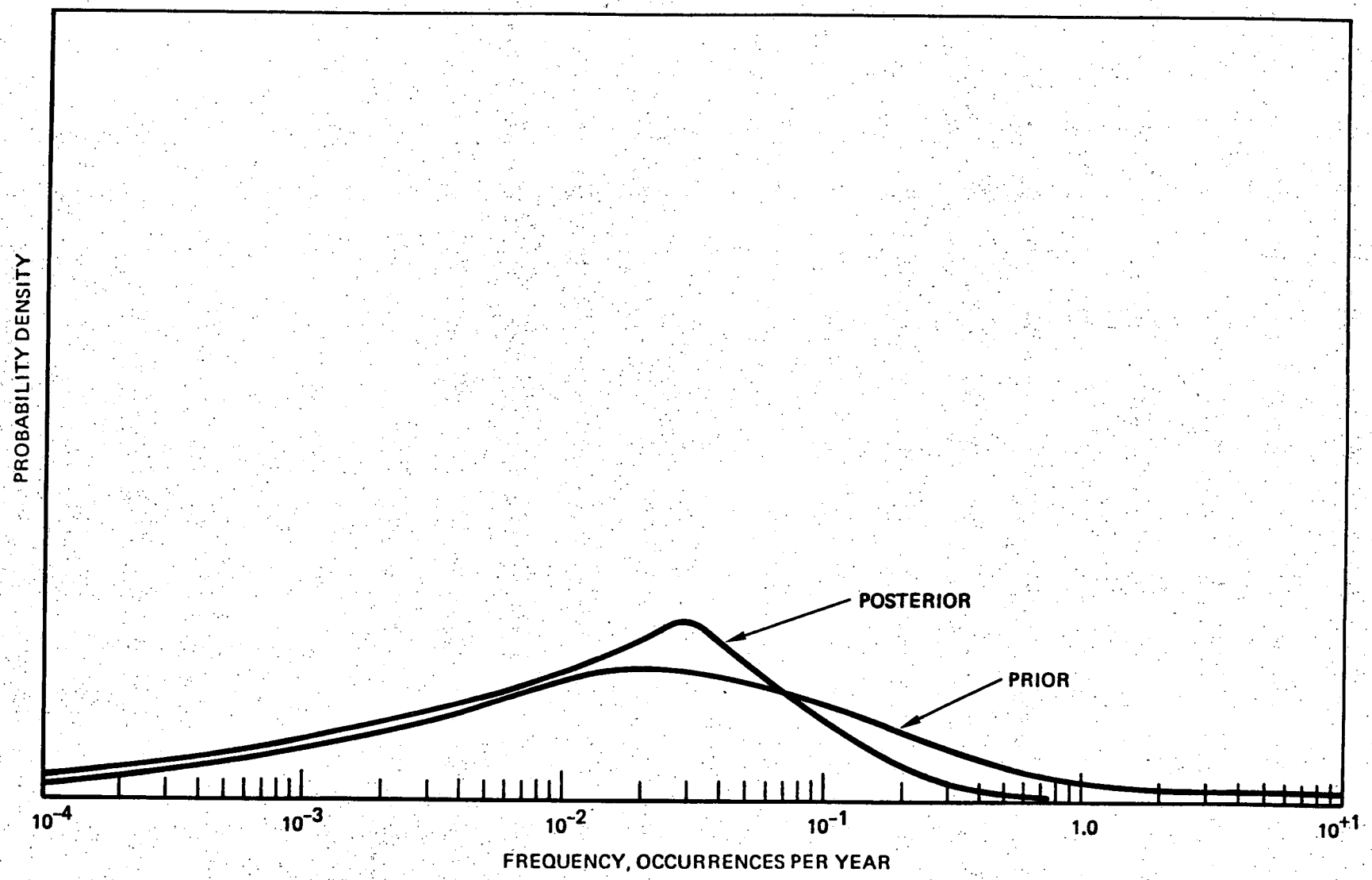

Figure 1.4.2-5. Probability Distribution for Frequency of Initiating Event 4 (Steam Generator Tube Rupture)

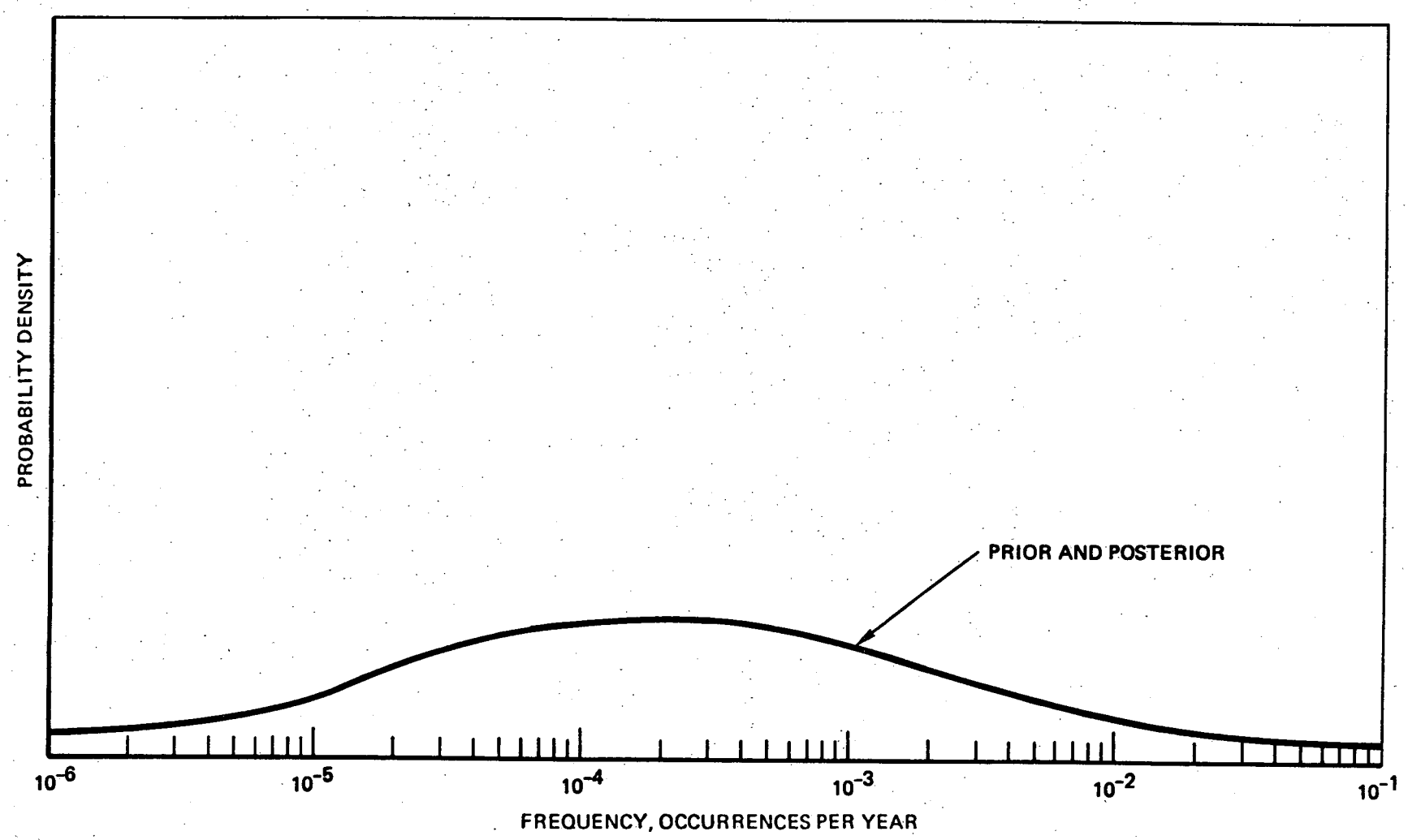

Figure 1.4.2-6. Probability Distribution for Frequency of Initiating Event 5 (Steam Break Inside Containment)

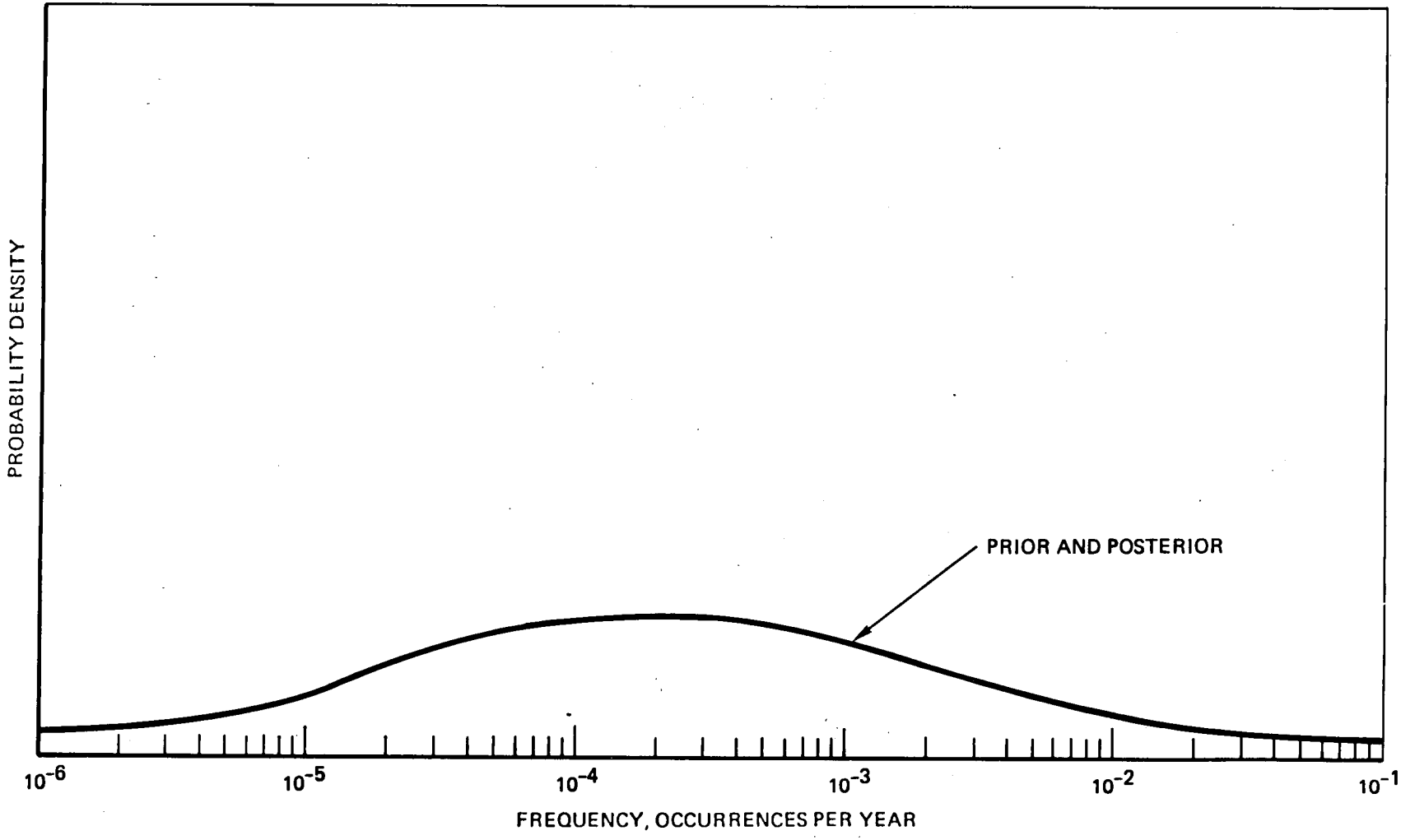

Figure 1.4.2-7. Probability Distribution for Frequency of Initiating Event 6 (Steam Break Outside Containment)

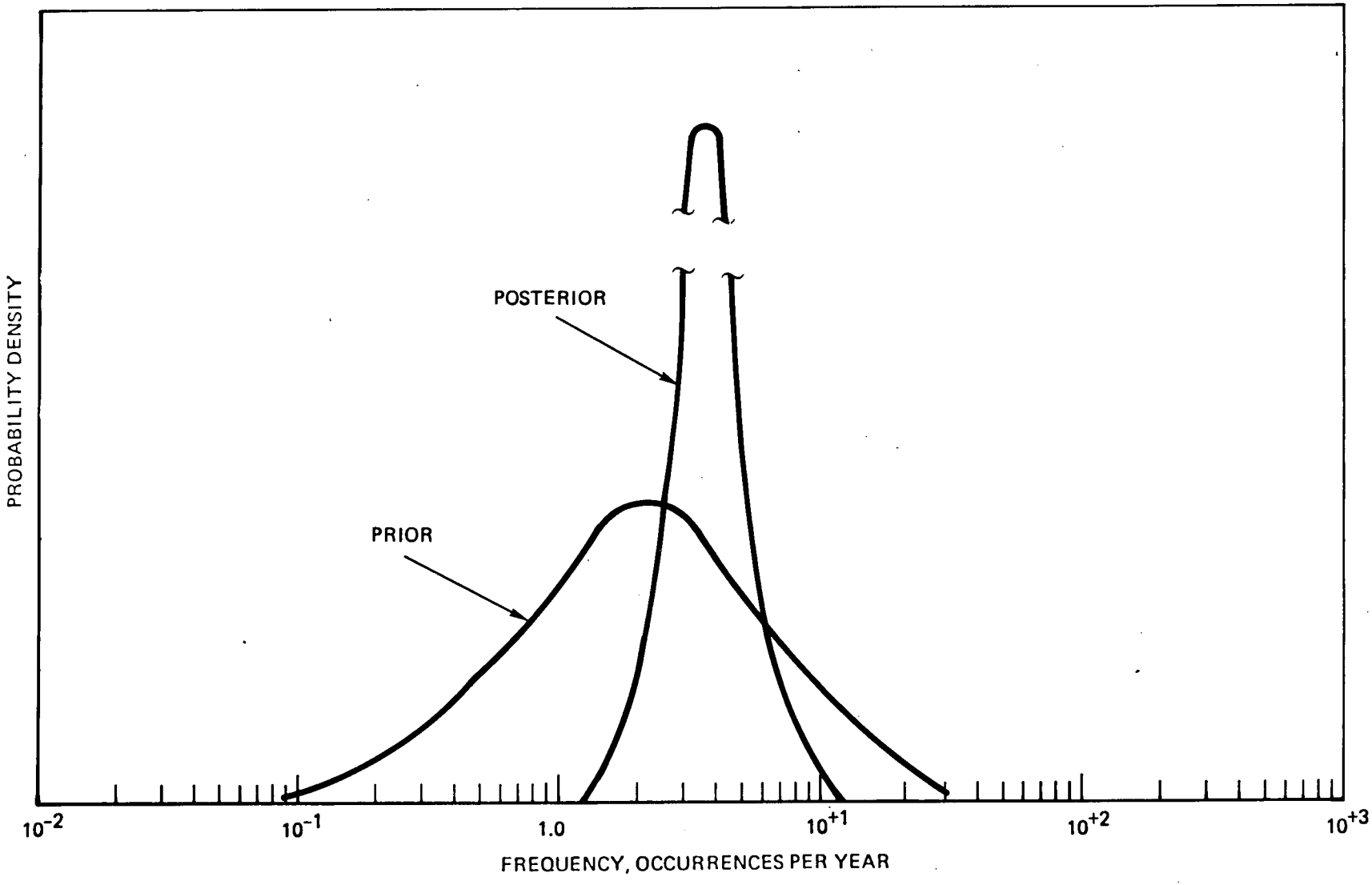

Figure 1.4.2-8. Probability Distribution for Frequency of Initiating Event 7 (Loss of Main Feedwater)

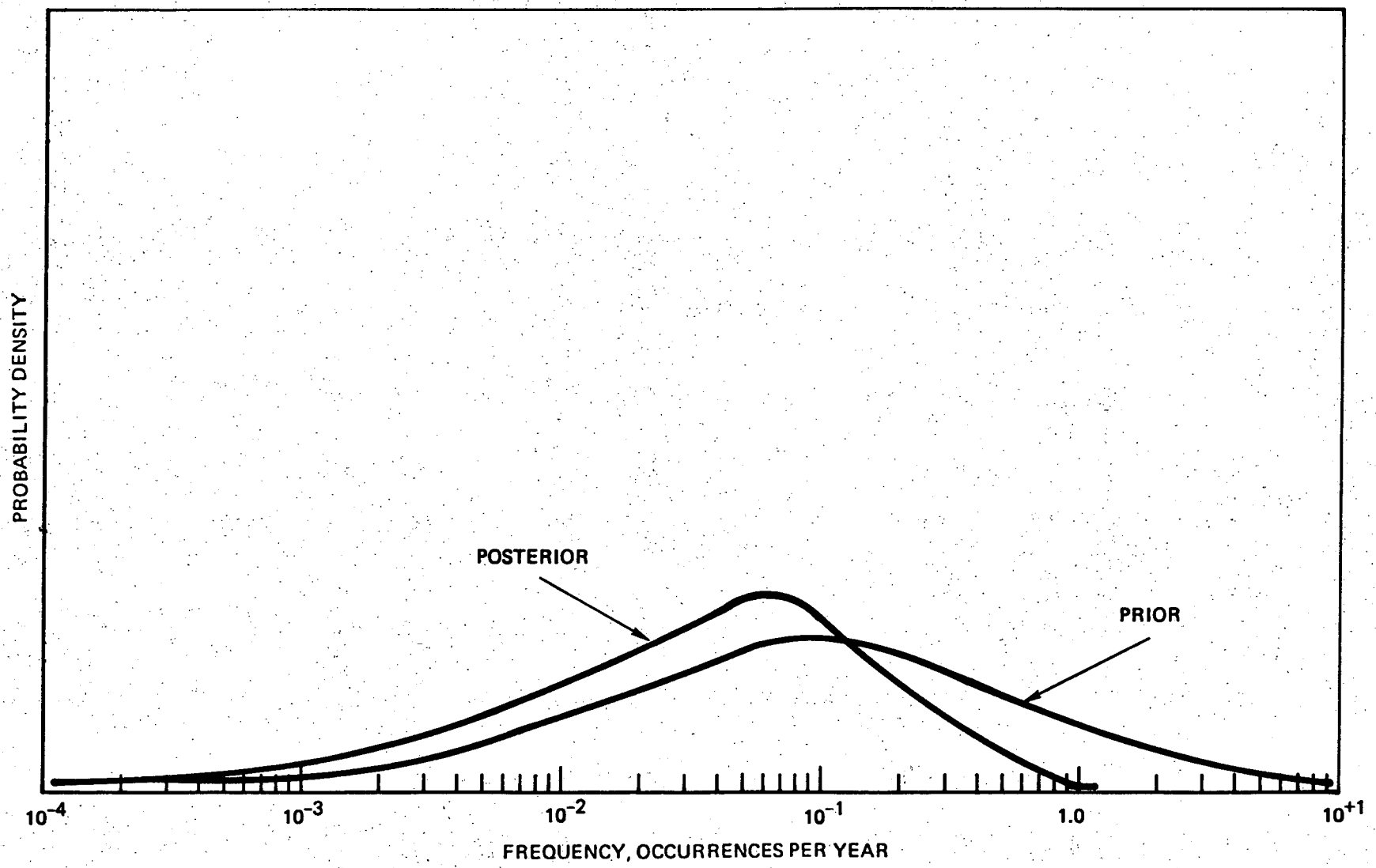

Figure 1.4.2-9. Probability Distribution for Frequency of Initiating Event 8 (Trip of One MSIV)

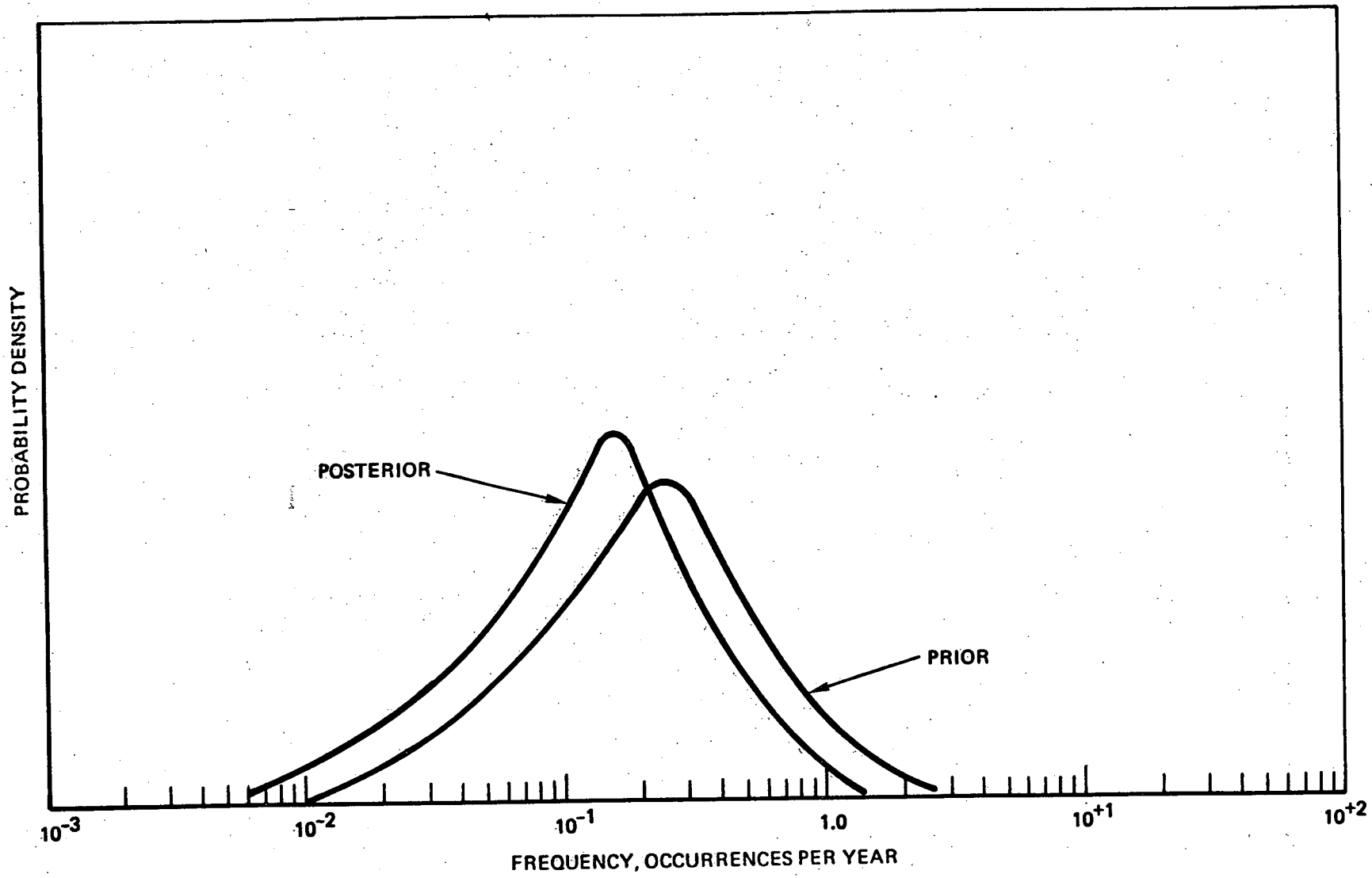

Figure 1.4.2-10. Probability Distribution for Frequency of Initiating Event 9 (Loss of RCS Flow)

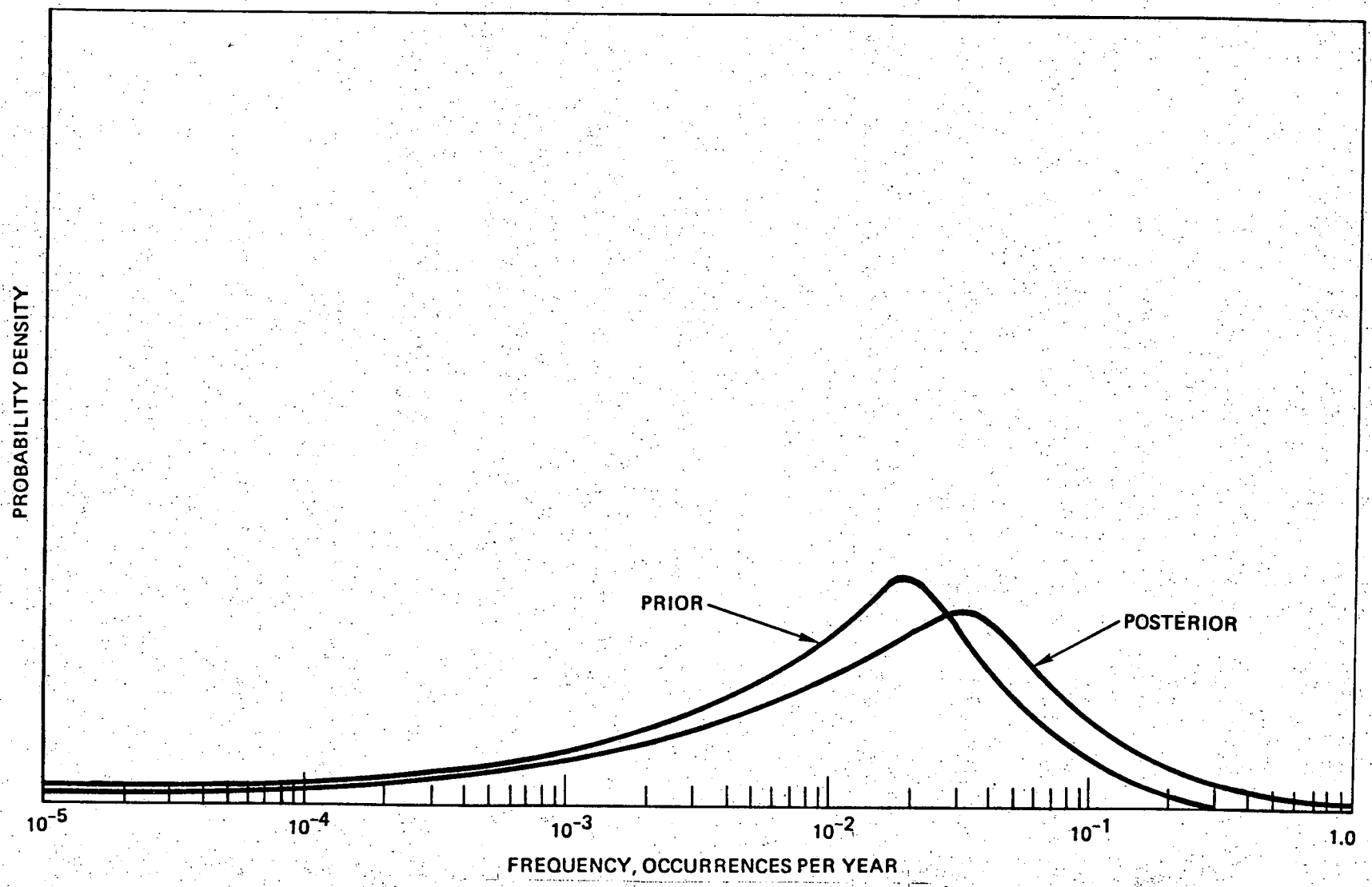

Figure 1.4.2-11. Probability Distribution for Frequency of Initiating Event 10 (Core Power Excursion)

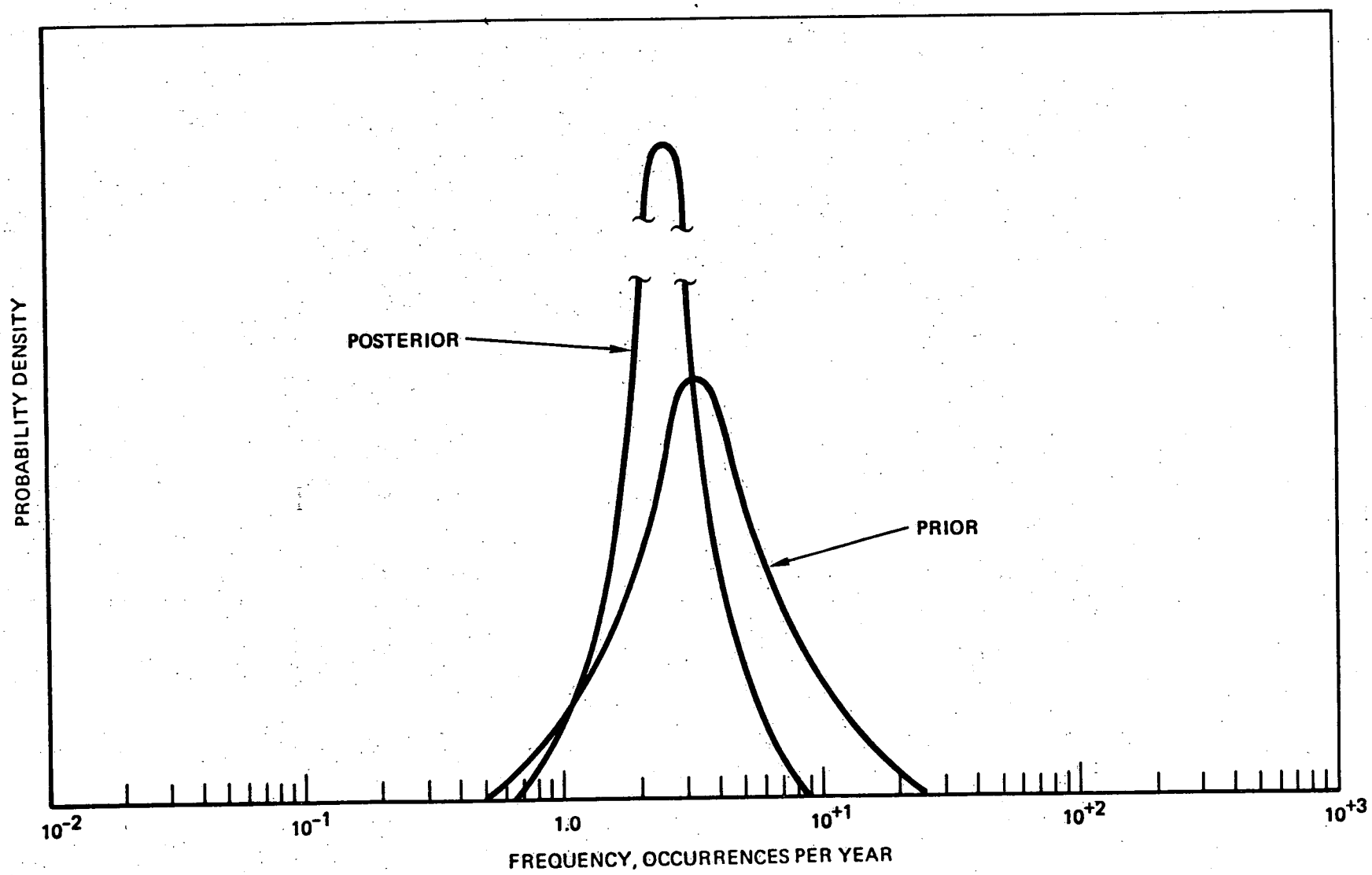

Figure 1.4.2-12. Probability Distribution for Frequency of Initiating Event 11a (Turbine Trip)

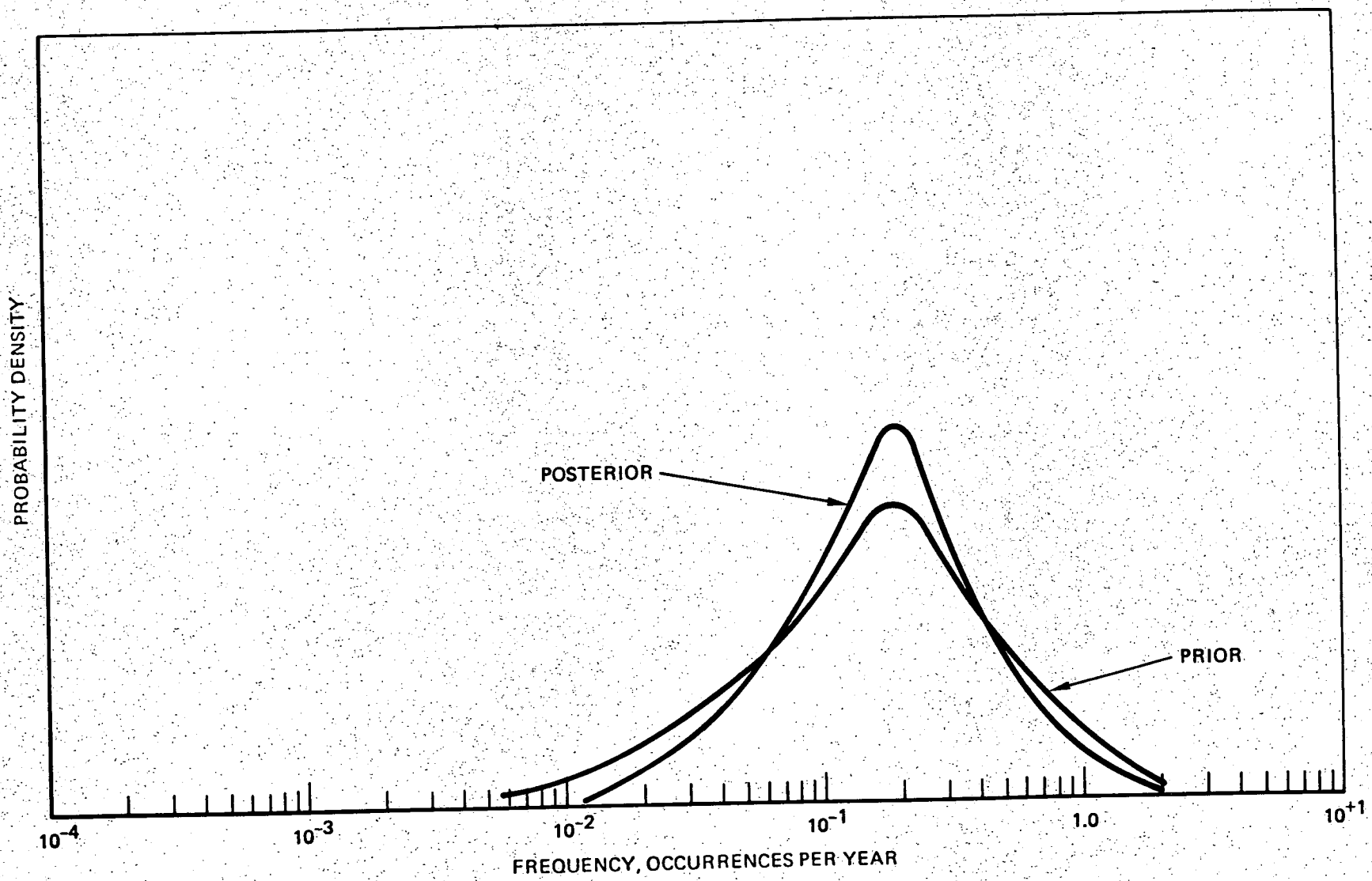

Figure 1.4.2-13. Probability Distribution for Frequency of Initiating Event 11b (Turbine Trip, Loss of Offsite Power)

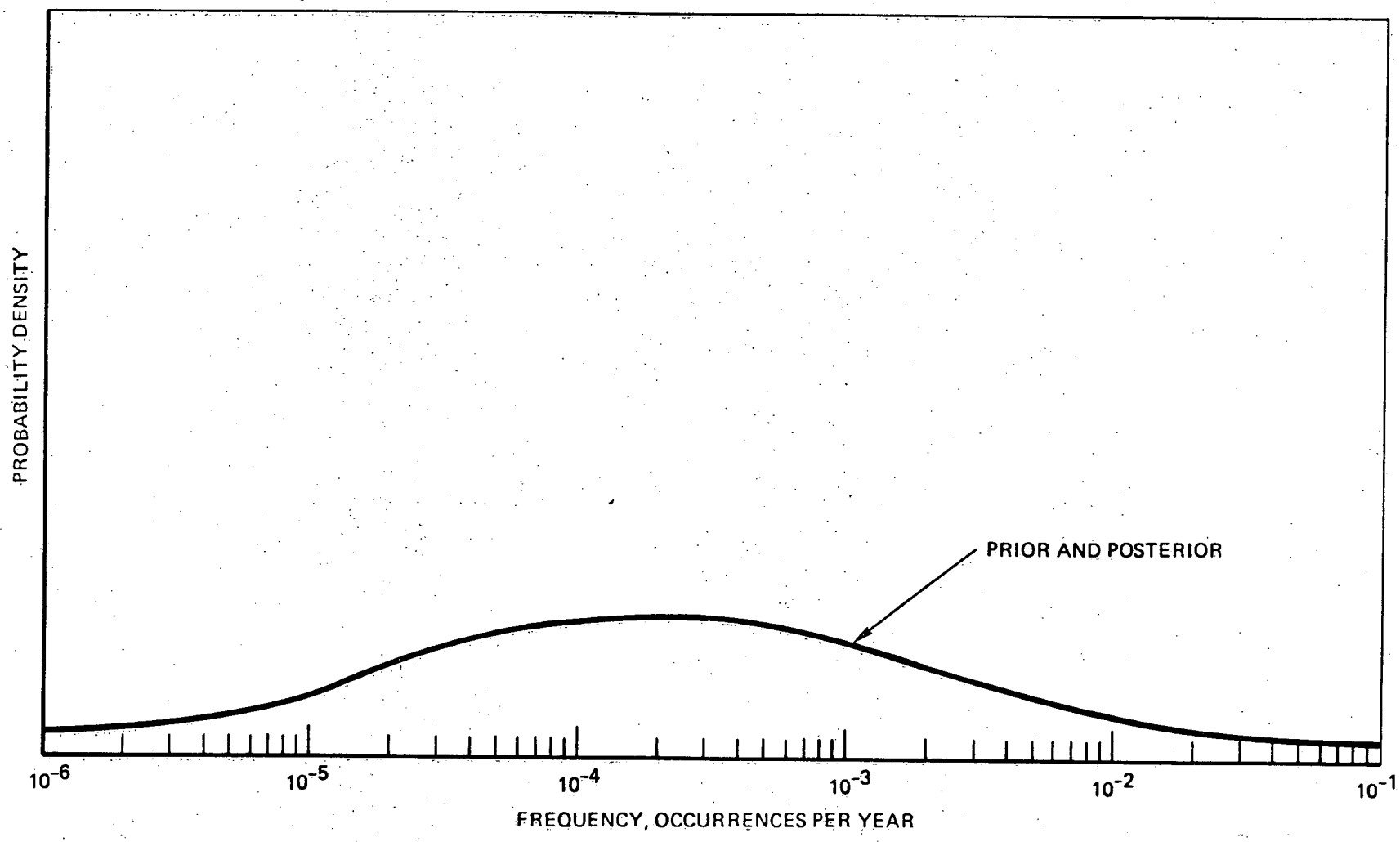

Figure 1.4.2-14. Probability Distribution for Frequency of Initiating Event 11c (Turbine Trip, Loss of Service Water)

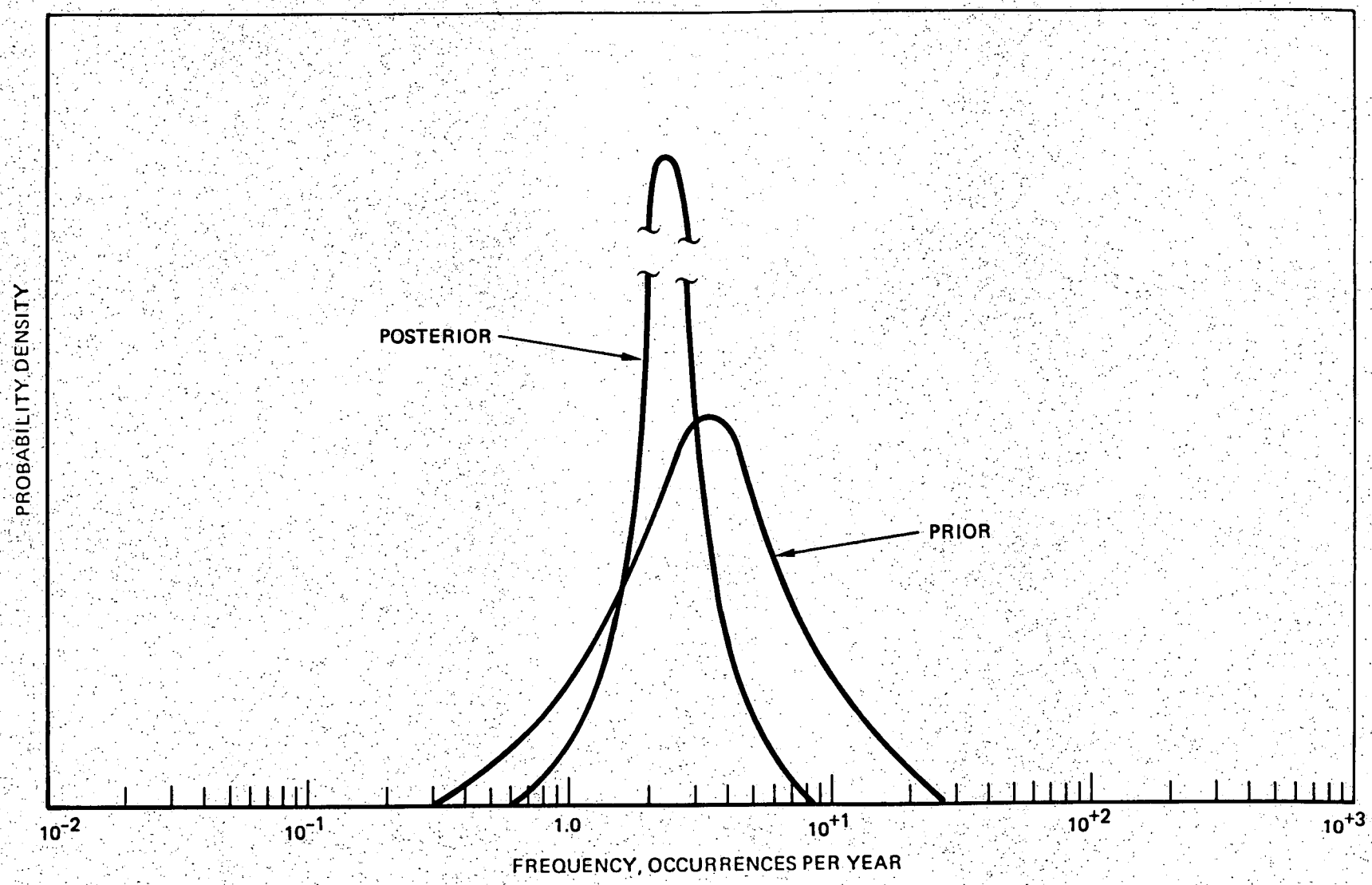

Figure 1.4.2-15. Probability Distribution for Frequency of Initiating Event 12a (Reactor Trip)

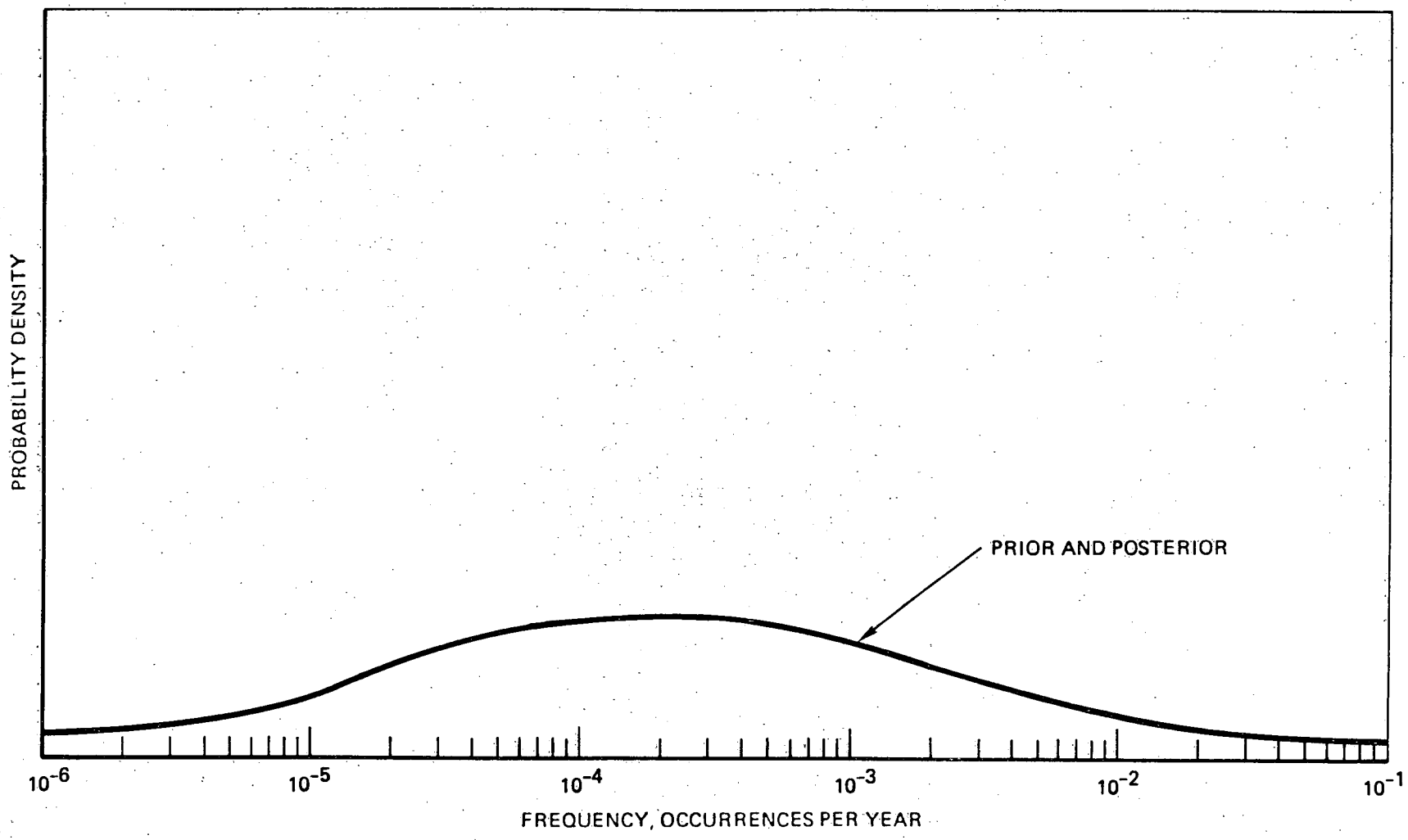

Figure 1.4.2-16. Probability Distribution for Frequency of Initiating Event 12b (Reactor Trip, Loss of Component Cooling)

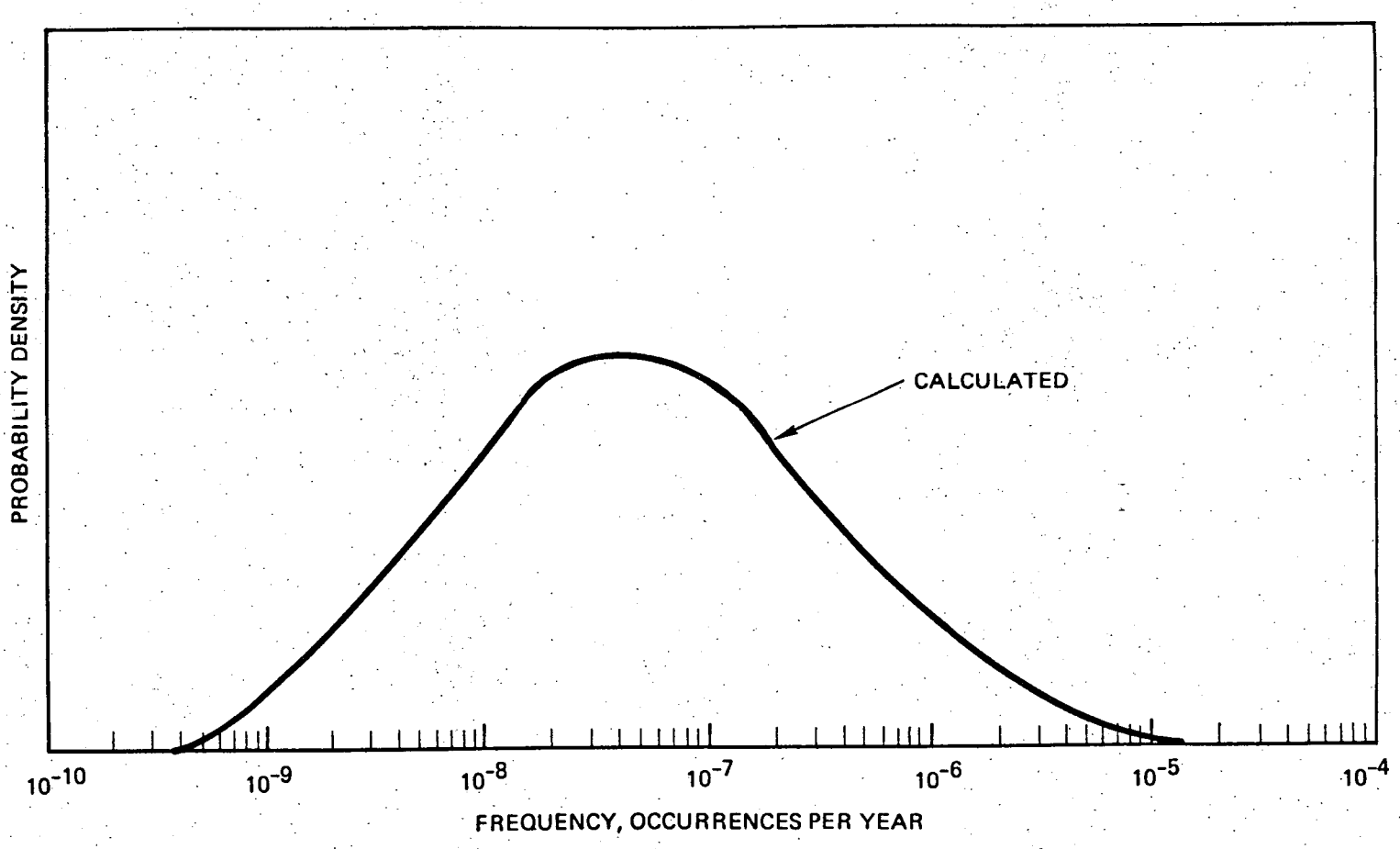

Figure 1.4.2-17. Probability Distribution for Frequency of Initiating Event V (Interfacing System LOCA)

1.5 INDIAN POINT 2 APPENDICES: DATA AND SYSTEMS ANALYSES

1.5.1 INDIAN POINT UNIT 2 DATA ANALYSIS

The methods for the analysis of data within the probability of frequency framework are described in Section 0, Probabilistic Risk Assessment Methodology. This section contains the implementation of the methodology for the derivation of generic and site specific distributions for the rates of occurrence of elemental events.

1.5.1.1 Site Specific Failure Data Base Development

1.5.1.1.1 Component Failure Data

1.5.1.1.1.1 Failure Definition The site specific component failure information developed in this data base is used as a basic input to the Bayesian specialization of available generic component failure distributions. These specialized distributions are applied to the corresponding components in each of the system fault trees during the quantification of hardware failure contributions to system unavailability. In this context, the definition of component failures used for this data base includes only those hardware failures which can be identified as attributable to an intrinsic property or state of the component or subsystem being analyzed. Specifically excluded from this data base are failures attributable to:

- Personnel errors and procedural errors. These failures are included in the analysis of human interactions with components and systems during operation, testing and maintenance activities.

- Causes generated by systems or components external to the component being analyzed. These failures are identified and included in the analysis of interfacing components and systems, and their effects are quantified through the analysis of system interdependencies and common cause initiators.

- Design, fabrication, and installation errors (for which documented corrections have been implemented and sufficient operating experience has been accumulated to demonstrate the efficacy of such corrections). Corrected errors are not considered as contributors to failure. Consideration and quantification of unidentified or latent uncorrected design, fabrication and installation errors are included in each system analysis, independent of hardware failures.

Descriptions of the specific failures included and, if appropriate, excluded from this data base are provided with the individual component failure mode data summaries presented in Section 1.5.1.1.5.

1.5.1.1.1.2 Failure Data Sources The primary source of basic component failure data used in this study was the Licensee Event Reports (LERs). The technical specifications and plant operating license reporting criteria require that LERs be submitted to the NRC as documentation of

all significant events that directly affect plant safety or affect those systems designed to maintain the plant in a safe condition. A compilation of all LERs submitted by Indian Point Unit 2 from prestartup construction in 1969 through December 1979 provided the basic event descriptions from which the corresponding failure items were drawn and evaluated for inclusion in the data base.

The information included in any source document cannot be directly used to construct a specific failure data base without first identifying, documenting, and understanding the constraints and implications associated with that information. Those constraints are discussed herein. Meanwhile, the LERs have significant advantages over other primary failure data sources for use in probabilistic risk assessment (PRA).

- The reporting criteria specify that all events affecting safety systems accident mitigation capabilities must be reported. Because this study is specifically concerned with the analysis of these capabilities, all LER items should be directly relevant to the development of this data base.

- Failures are generally reported for the plant operating modes that are of primary concern in this study: power operation and, in some cases, hot shutdown.

- The LERs are a source of relatively consistent, reviewed, and generally complete event descriptions. Because each observed event must be evaluated relative to common reporting criteria, the items reported in the LERs provide a relatively consistent information base that can be applied across different systems in any given plant. To a much lesser extent, due to the inherent subjectivity of intent interpretation and due to subtle differences in the criteria applied and technical specifications limitations imposed at different plants, these general reporting criteria also provide a basis for broad consistency in the types and applicability of events reported from several plants. However, direct comparisons of these reports cannot be made without full evaluation of the bases for and application of the specific reporting criteria at each individual station.

- The LERs provide a fully verifiable source of primary component failure data. Because all the other available sources of failure information are subject to many of the same limitations that apply to the LERs, a principal advantage in using the LERs in this study is that they are a uniquely verifiable source of data and are readily available to all potential users and review personnel.

A number of additional sources of primary component failure data were also used if more detailed information on specific items was needed than was available in the LER summaries. These sources included control room equipment operating logs, component maintenance records, testing records, and station internal event reporting documents [Significant

Occurrence Reports (SORs)]. The SORs are a large volume of raw data covering a wide range of events documented during all phases of plant operation. They provide a complete record of all component failures observed at the station. (The SORs are the preliminary documents for all failures that are ultimately reported as LERs.) However, because of the volume, variability, and lack of detail in the SORs, they were primarily used as reference documents for this study. No detailed effort was made to reduce their information content to a form directly applicable to this data base.

The primary concerns in the development of this site specific data base were that it must be: (1) internally consistent, and (2) fully verifiable. Because of these concerns, any modifications, additions or deletions made to the failure data reported in the LERs have been applied only when specific documentation was available to fully justify such modifications. In all such cases, this documentation or a direct reference to its source is provided with the affected component failure mode data summary.

It is important to make a few observations about the limitations of existing data sources, including LERs, with respect to probabilistic risk assessment work. First, a comprehensive data collection system designed specifically to support PRA does not exist. The existing data systems have all evolved from either licensing-related criteria or plant performance analysis requirements. For example, PRA does not draw boundaries around systems according to safety system classifications or technical specifications. Rather, the scenarios and event sequences define the systems and, therefore, the data of interest. The result is that some failures and failure modes useful for PRA analysis may not be reported if the plant sticks only to safety criteria. The same applies to plant operating conditions.

Additionally, regardless of the data system, judgment is always involved. All failures require some interpretation by the plant staff--was it a failure, is it a reportable event, what is the mode, the apparent cause, etc.

Recognizing the limitations of LERs as a data source for PRA, an effort was made to review detailed station records at Indian Point Unit 2 to ensure that the LERs provided a representative data base for Indian Point. The data base used is believed to be sound. Where uncertainties exist, the probabilistic framework accommodates quantification of such uncertainties.

1.5.1.1.2 Component Operability Tests and Service Hours Data

1.5.1.1.2.1 <u>Data Base Definition</u>

1.5.1.1.2.1.1 Operating Modes. The distinction between cold and noncold shutdown (i.e., hot shutdown, or power operation) conditions in plant operating modes is important for the development of a site specific failure data base that uses the LERs as the primary source of

component failure information. The principal reasons for distinguishing between these two modes (as opposed to modes such as power operation versus shutdown, or critical versus noncritical) are:

- LER reporting criteria are significantly different when the plant enters the cold shutdown condition (very few events which occur during cold shutdown are reportable).

- The technical specifications operability criteria for safety systems and components generally specify that operability restrictions do not apply during cold shutdown.

- Operating, maintenance, and system testing procedures and practices are modified significantly when the plant enters the cold shutdown condition.

- The plant operating modes of primary concern in this study are power operation and, in some cases, hot shutdown.

Table 1.5.1-1 summarizes the periods since initial reactor criticality during which Indian Point Unit 2 was in the cold shutdown mode of operation. Only operating times between May 23, 1973, (initial criticality) and December 31, 1979, were included in this failure data base. This time span was based on the availability of failure event information from the LERs, and the operability, testing, and reporting criteria specifically applied following initial criticality.

1.5.1.1.2.1.2 Testing Frequencies. Periodic testing that is required by the plant technical specifications is generally performed monthly (during power operation), quarterly (during any calendar quarter for which the unit was not in continuous cold shutdown), annually, or during regular refueling outages. Variable frequency testing that is not required by the technical specifications is performed as specified in the individual test procedures and as plant operating conditions allow. The operating periods summarized in Table 1.5.1-1 and the general testing frequency criteria outlined were used to develop of the periodic testing data shown in Table 1.5.1-2. As an example of the use of this frequency data, consider component "X", which, according to the station's periodic testing procedures, is tested monthly during power operation. The total number of tests performed on component "X" between initial criticality and the end of 1979 is 65. If component "Y" is tested quarterly, then the total number of component tests for "X" and "Y" together is 90.

1.5.1.1.2.2 Component Test Data Synthesis. Specific details of the number of component tests performed at each of the periodic testing intervals are provided with the individual component failure mode data summaries in Section 1.5.1.1.5. The number of tests listed for each interval is the total number of component tests performed at that interval. The total number of component tests in the period is the

product of this periodic test data and the testing frequency data presented in Table 1.5.1-2. For example, consider the following:

- Test 1 is performed monthly and verifies the operability of three motor-operated valves.
- Tests 2 and 3 are each performed quarterly and verify the operability of one and 18 motor-operated valves, respectively.
- No other tests are performed to verify motor-operated valve operability.
- The total number of valve tests per month is three.
- The total number of valve tests per quarter is 19.
- The total number of valve tests for the data base period is: 3(65) + 19(25) = 670 valve tests (from 1973 through 1979.)

All the station's periodic test procedures were reviewed to identify the specific components tested and the failure modes verified by each of these procedures. For many of the failure modes presented in the data base (e.g., motor-driven pump failure to start on demand), specific operations performed during the testing process provided direct evidence of component operability (e.g., start pump "X"). For a large number of failure modes, however, no analogous specific operations were provided to directly verify component successes. The number of corresponding actual component tests was determined by noting the success criteria and parameters monitored in each testing procedure. This information was combined with the applicable system piping and instrumentation diagrams, with flow path configurations altered, if necessary, as they are affected by the testing procedure. Successful component tests were counted only if: (1) the testing procedure provided direct evidence of successful operation or an unfailed state of the component, and (2) a failure of the component would have resulted in an unsuccessful test requiring an LER. For example, consider the component failure mode "manual valve transfers closed". Referring to the example piping diagram shown in Figure 1.5.1-1, a system flow test is performed to verify the operability of pump X by closing motor-operated valve A and running the pump on recirculation flow. Successful performance of the test requires that the pump start and that adequate flow be observed at flow gauge F. This test, in addition to verifying pump X operability to start and run, provides the following test data information:

- The piping from the suction source through the recirculation line is not plugged.
- Check valve C opens successfully.
- Manual valves M1, M2, and M3 are open.

The test does not provide any information about the status of motor-operated valve A or manual valve M4, because they are not included in the test flow path. (Excessive leakage through A could be detected if a flow path was available downstream from A, if valve M4 had not failed closed, and if the leakage was sufficient to degrade the flow through F. However, this failure of A would not be detected if valve M4 had also failed. Because this test cannot detect this failure of M4, these valves are not included in the success data.) This general process was applied to all the systems analyzed in this study for periodic testing and normal operating configurations to develop the successful testing data to be combined with these (generally passive) component failure modes. In all such cases, the application of this methodology is specifically referenced in the data summaries for the applicable component failure modes.

1.5.1.1.2.3 Component Service Hours Data Synthesis. The service hours data reported in the component failure mode data summaries was developed by analyzing the following three general states of operability verification:

1. Components whose operability is monitored continuously during normal plant operating conditions.

2. Components whose operability is verified during periodic testing and whose state does not change between tests.

3. Components whose operability is verified only during the periodic tests.

For those components that are in continuous service during normal plant operation, the only times included in the service hours are those when failure of the component would be reportable as an LER. (For example, if pump "X" is normally running during all modes of unit operation, and the technical specifications require that its failure be reported only during noncold shutdown periods, the cold shutdown running hours are excluded from the pump service hours data.) For those components whose state remains unchanged between periodic tests, the service hours include only the periods between such tests during which the component failure would be reportable as an LER. (For example, valve "Y" is verified open during a quarterly system flow test, as described in Section 1.5.1.1.2.2, and a failure of the subsystem of which "Y" is a portion is required to be reported only during noncold shutdown periods. If the unit is placed in cold shutdown for 1 month between quarterly tests, the total service period applied to "Y" during that quarter is only 2 months because a failure occurring during the cold shutdown month would not be reported, and a system operability verification test required to be performed prior to leaving cold shutdown would establish Y's operability for the remainder of the period.) For those components whose operability is verifiable only during the periodic tests, the service hours include only the applicable test operating times. (For example, if pump "Z" is operated only during a monthly flow test, the service hours applied to the pump failure mode

"fails during operation" include only the pump's actual monthly operating hours.) In all cases, the criteria used to establish the component service hours data for the specific failure mode reported are documented with the failure mode data summaries in Section 1.5.1.1.6.

1.5.1.1.3 Component Failure Mode Definition

In most cases, the specific component failure mode of interest in this study has been defined by the type of component and its function within the system being analyzed (e.g., "check valve fails to open"). In some cases, however, the reported failure modes have been defined by a combination of influences including the level of detail to which the systems are modeled in the fault tree analyses and the level of detail available in the generic failure data distributions.

In principle, the site specific failure data should be traceable not only to a specific component, but also to a subcomponent and a "subfailure" level (e.g., check valve "X" failed to open because 3/4-inch bolt "A" became corroded due to interaction with caustic solution "Q," etc.). However, the system fault trees are not developed to this level of detail. This is because microscopic analysis generally reduces understanding of the relevant system failure modes and of the dominant failure contributors, and instead focuses attention on a narrowly defined analysis of aggregates of individual subcomponents. In addition, in most cases, the actual data is not as well defined at this microscopic level of detail as it is at the macroscopic component level. (For example, the check valve may have failed to open because of bolt corrosion or because of hinge pin swelling, but it did fail to open.) Therefore, the actual state of knowledge about component failures is often clearest only for a combination of subcomponent failure modes which are manifested in a single observable, verifiable, and simply documentable effect. In addition, as a practical consideration, the generic data distributions to be specialized with the site specific failure data are usually not available in the literature at the level of detail which can be generated from the site specific failure data sources. In most of these cases, similar component types and failure modes have been combined in the site specific data base to provide consistency and compatibility between these two data sources.

Specific examples of items for which the site specific component failure mode definition has been strongly influenced by the available level of generic data include:

- Motor-Operated Valves Failure to Operate on Demand. The generic data distribution for motor-operated valve active failures is best defined for the failure mode "fail to operate" which includes the failure modes "fail to open" and "fail to close." Because the precise contributions of each of these modes to the generic data cannot be discerned and both of these failure modes actually define a failure of the valve to change states on demand, the more detailed site specific data have also been combined into the single "fail to operate" mode. (In this case, a test which fully cycles a valve

open-closed-open strictly constitutes one test each of the failure modes "fail to close" and "fail to open." Either of these failures would be reported as a "failure to operate" and only one failure would be reported for the test. Therefore, the entire cyclic test is conservatively counted as a single test of the valve failure mode "fail to operate.")

- Motor-Operated Valves and Manual Valves Transfer Closed (or transfer open). Because the failure causes are physically similar for motor-operated and manual valves (no evidence is available from the site specific data to indicate that spurious operation of the motor operator contributes significantly to differences between the two valve types), and because only a single generic distribution is available for each of these failure modes, motor-operated and manual valves are combined into a single component category for each of these failure modes. (Air-operated valves are documented separately, however, because their identifiable failure causes are physically different from those of manual and motor-operated valves.)

- Definition of "Pump" Failure. Power supply circuit breakers, electrical and mechanical controls, motors, pump shafts, and other pump mechanical components are combined into a single component defined as a pump because the generic failure data does not differentiate among failures of these subcomponent categories. Therefore, a pump failure to start could be due to a circuit breaker failure, low oil pressure, or a ruptured shaft, but each of these failures would be categorized as a failure of the pump to start.

The component failure mode data reported for motor-driven pumps deserves special attention because these pumps are combined for one type of failure mode, but are retained as independent components for another failure mode. All similarly sized motor-driven centrifugal pumps analyzed in this study are combined in the development of a single "failure to start" failure mode. This is because only a single, well defined generic distribution is available for this failure mode, and because the observed causes for a wide variety of pumps failing to start are physically identical (e.g., circuit breaker failures, control circuit failures, contact failures, etc.). Therefore, the macroscopic data base for this specific failure mode does not differentiate between motor-driven pumps in different systems because all the motor-driven pumps considered in this study exhibit the same failure characteristics on starting. However, even though only a single generic distribution is available for the failure of motor-driven pumps during operation, the motor-driven pumps in each of the systems analyzed in this study exhibit unique operating characteristics attributable to such factors as design, orientation, physical location, and normal operating duty. Therefore, the failure data base has been defined independently for each of these pump types during pump operating periods to take full account of these physical differences. (For example, a large vertical shaft pump under continuous service will exhibit significantly different operating failures from a horizontal pump located in an adverse environment and subjected to only intermittent starts.) By specializing the single

generic distribution for pump failure data (which indicates a relatively diffuse prior state of knowledge about differences between the pumps) with the individual pump site specific failure rate information, these physically observable differences are thus retained as uniquely identifiable contributors to each pump's availability during operation.

1.5.1.1.4 Uncertainty in Site Specific Data

A significant problem with many of the existing generic component failure data bases is their inconsistency in evaluating the numerator and denominator in the failure rate expression (i.e., the number of failures and the corresponding number of tests, operating hours, or demands). The development of a consistent site specific component failure data base for this study included a conscientious effort to ensure that the population success data (the denominator) obtained from the Indian Point 2 records was compatible with the failure data obtained from the LERs.

The basic sources of information used to develop this population success data included plant testing and operating procedures, normal and nonroutine system alignments, and general plant failure and maintenance data records. Each of these sources was evaluated in the context of the Indian Point 2 failure data reporting criteria to determine the applicability of the information. The system flow paths and alignments established by each test and operating procedure were examined to identify the component types and failure modes verified during the applicable period. The plant operating procedures and periodic test schedules provided the necessary input to determine the frequency and duration of the majority of these operations. Plant maintenance records and the technical specifications were used to determine the frequency of nonroutine tests required when equipment was removed from service. For each system configuration, the following questions were asked for each component:

- What failure mode is tested by this configuration?
- Would this failure be detected through either indications during normal system operation or through the acceptance criteria for the test?
- If detected, would the failure be reportable as an LER under the Indian Point 2 technical specifications?

The success data was included only if all of these questions could be answered affirmatively.

Although a few component failures may have been omitted from the data base because of the nature and availability of the LERs, it is believed that it is equally likely that a corresponding percentage of the tests and operating hours may not have been included because they could not be easily extracted from plant records or because they could not be verified as being compatible with the failure data. Therefore, it is

believed that additional data, if it were available, would not change the reported site specific failure rates by more than 10%. Because of the strict criteria applied to the population success data to ensure compatibility with the reported failures, it is also believed that the reported failure rates are likely to be slightly conservative (i.e., additional data would most probably result in a slight reduction of the failure rates).

1.5.1.1.5 Data Base Applicability

In general, the site specific data presented in this data base is strictly defined only in the context of this study. Because of the limitations inherent in the use of component failure data from the LERs, the data base development methodology used in this study has applied specific criteria to the synthesis of failure and success data to produce a consistent, realistic, conservative presentation of the available state of knowledge of component hardware failure rates at Indian Point Unit 2. Although the consistent application of this methodology provides a basis for comparing this data with data from the other plants analyzed in this study, such a comparison is possible only in the specific framework of this analysis and is not directly adaptable to other applications.

1.5.1.1.6 Plant Specific Component Failure Mode Data Summaries

Component Type	Failure Mode	Page
Manual Valves	Transfer closed	1.5-12
	Transfer open	1.5-13
Check Valves	Fail to open	1.5-14
	Fail to seat	1.5-15
Relief/Safety Valves	Premature opening	1.5-16
Motor-Operated Valves	Failure to operate	1.5-17
	Transfer closed	1.5-18
	Tranfser open	1.5-19
Air-Operated Valves	Failure to operate	1.5-20
	Transfer closed	1.5-21
	Transfer open	1.5-22
Motor-Driven Pumps	Failure to start	1.5-23
Turbine-Driven Auxiliary Feedwater Pumps	Failure to start	1.5-24
Safety Injection Pumps	Fail during operation	1.5-25
Residual Heat Removal Pumps	Fail during operation	1.5-26

Component Type	Failure Mode	Page
Component Cooling Pumps	Fail during operation	1.5-27
Auxiliary Component Cooling Pumps	Fail during operation	1.5-28
Service Water Pumps	Fail during operation	1.5-29
Recirculation Pumps	Fail during operation	1.5-30
Containment Spray Pumps	Fail during operation	1.5-31
Motor-Driven Auxiliary Feedwater Pumps	Fail during operation	1.5-32
Turbine-Driven Auxiliary Feedwater Pump	Fail during operation	1.5-33
Containment Fan Coolers	Failure to start	1.5-34
	Fail during operation	1.5-35
Heat Exchangers	Rupture	1.5-36
	Plugged - tube side	1.5-37
	Plugged - shell side	1.5-38
Diesel Generators	Failure to start	1.5-39
	Fail during operation	1.5-40
Bus Feed Circuit Breakers	Fail to close	1.5-41
	Fail to open	1.5-42
	Transfer open	1.5-43
AC Power Transformers	Fail during operation	1.5-44
Static Inverters	Fail during operation	1.5-45
DC Power Batteries	Fail during operation	1.5-46
Battery Chargers	Fail during operation	1.5-47
DC Control Power Transfer Devices	Fail to transfer	1.5-48
DC Control Power Transfer Devices	Transfer open/fail open	1.5-49
Buswork	Catastrophic failure during operation	1.5-50

Component Type: MANUAL VALVES

Failure Mode: Transfer Closed

- Total Component Service Hours in Period: 5.2×10^6

  Basis: Data base includes service hours for valves verified to be open by actual fluid flow through valve during periodic test or normal operation. Standby system valves remaining open between flow tests are included for the duration of the periods between tests since performance of the test would detect failure. Service hours exclude periods during which failure would not be reportable or during which actual flow verification was not required (e.g., cold shutdown periods for several systems).

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: MANUAL VALVES

Failure Mode: Transfer Open/Excessive Leakage Through Valve

- Total Component Service Hours in Period: 703

  Basis: Data base includes service hours during which valves are verified to remain closed through periodic system flow testing or normal operation, and includes only those periods during which the valves are subjected to pressure or flow conditions (e.g., valves closed for a flow test and reopened after the test is completed are included only for the duration of the flow test). Valves whose failure during normal operation would not result in reportable system degradation are excluded from the data base.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: CHECK VALVES

Failure Mode: Failure to Open on Demand

- Test Data:

  - Number of Tests Per Month: 18
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 25
  - Number of Tests Per Refueling: 33
  - Total Number of Tests in Period: 1,444

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: CHECK VALVES

Failure Mode: Failure to Seat/Excessive Reverse Leakage

- Total Component Service Hours in Period: 4.44×10^5

  Basis: Data Base includes service hours during which valves are verified to remain closed through perodic system flow testing or normal operation and includes only those periods during which the valves are subjected to pressure or flow conditions. Valves whose failure during normal operation would not result in reportable system degradation are excluded from the data base.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
05/23/78	Safety Injection Pump 22 Discharge Check Valve	Broken Hanger Brackets

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: RELIEF/SAFETY VALVES

Failure Mode: Premature Opening or Leakage

- Total Component Service Hours in Period: 3.01×10^5

  Basis: Data base includes service hours for valves of similar type to those in systems analyzed in this study and whose failures would be reportable under normal system operating conditions. Valve service hours during periods for which failure would not result in reportable system degradation or reportable corrective actions are excluded from the data base. The specific valves included in the data base are:

  - Accumulator Relief Valves
  - Letdown Relief Valve
  - RHR to Letdown Relief Valve
  - Boron Injection Tank Relief Valve

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
12/2/79	Letdown Relief Valve 203	Degraded Valve Seat

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: MOTOR-OPERATED VALVES

Failure Mode: Failure to Operate on Demand

- Test Data:

  - Number of Tests Per Month: 4
  - Number of Tests Per Quarter: 38
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 17
  - Total Number of Tests in Period: 1,261

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
03/18/75	Cold Leg Injection Valve MOV 856A	Limitorque Operator Cracked
03/25/75	Component Cooling to RHR Heat Exchanger MOV 822A	Stripped Teeth in Valve Operator
05/07/77	Component Cooling to RHR Heat Exchanger MOV 822B	Torque Switch Malfunction

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: MOTOR-OPERATED VALVES

Failure Mode: Transfer Closed

- Total Component Service Hours in Period: 7.97×10^5

  Basis: Data base includes service hours for valves verified to be open by actual fluid flow through valve during periodic test or normal operation. Standby system valves remaining open between flow tests are included for the duration of the intertest periods, since performance of the test would detect failure. Service hours exclude periods during which failure would not be reportable or during which actual flow verification was not required (e.g., cold shutdown periods for several systems).

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: MOTOR-OPERATED VALVES

Failure Mode: Transfer Open/Excessive Leakage Through Valve

- Total Component Service Hours in Period: 818

  Basis: Data base includes service hours during which valves are verified to remain closed through periodic system flow testing or normal operation, and includes only those periods during which the valves are subjected to pressure or flow conditions (e.g., valves closed for a flow test and reopened after the test is completed are included only for the duration of the flow test). Valves whose failure during normal operation would not result in reportable system degradation are excluded from the data base.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and operating status summary

- Failure Data Source: LERs

Component Type: AIR-OPERATED VALVES

Failure Mode: Failure to Operate on Demand

- Test Data:

-	Number of Tests Per Month:	3
-	Number of Tests Per Quarter:	29
-	Number of Tests Per Year:	18
-	Number of Tests Per Refueling:	2
-	Total Number of Tests in Period:	1,052

- Failure Data for Given Failure Mode:*

Date	Reported Failure	Cause
05/02/78	Diesel Generator Cooling Water Regulating Valve FCV 1276A	Unspecified

- Test Data Source: Test review

- Failure Data Source: LERs

*Data base excludes two valve failures reported on 5/7/77, since the affected valves have been replaced with a new design which is not susceptible to the reported failure mode (internal binding).

Component Type: AIR-OPERATED VALVES

Failure Mode: Transfer Closed (mechanical failures other than those due to air pressure variations)

- Total Component Service Hours in Period: 4.44×10^5

  Basis: Data base includes service hours for valves verified to be open by actual fluid flow through valve during periodic test or normal operation. Standby system valves remaining open between flow tests are included for the duration of the intertest periods, since performance of the test would detect failure. Service hours exclude periods during which failure would not be reportable or during which actual flow verification was not required (e.g., cold shutdown periods for several systems).

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: AIR-OPERATED VALVES

Failure Mode: Transfer Open/Excessive Leakage Through Valve (mechanical failures other than those due to air pressure variations)

- Total Component Service Hours in Period: 3.7×10^4

  Basis: Data base includes service hours during which valves are verified to remain closed through periodic system flow testing or normal operation, and includes only those periods during which the valves are subjected to pressure or flow conditions (e.g., valves closed for a flow test and reopened after the test is completed are included only for the duration of the flow test). Valves whose failure during normal operation would not result in reportable system degradation are excluded from the data base.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: MOTOR-DRIVEN PUMPS

Failure Mode: Failure to Start on Demand

- Test Data:

  - Number of Tests Per Month: 11
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 9
  - Number of Tests Per Refueling: 5
  - Total Number of Tests in Period: 793

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
05/07/77	Service Water Pump 24	Breaker Malfunction
01/04/78	Service Water Pump 21	Breaker Failure
03/15/74	Service Water Pump 21	Unspecified
05/07/77	Auxiliary Component Cooling Pump 22	Dirty Auxiliary Contacts
05/02/78	Auxiliary Component Cooling Pump 22	Unspecified
05/22/74	Auxiliary Feedwater Pump 21	Dirty Auxiliary Contacts
06/02/78	Safety Injection Pump 22	Thrust Bearing Failure

- Test Data Source: Test Review

- Failure Data Source: LERs

Component Type: TURBINE-DRIVEN AUXILIARY FEEDWATER PUMP

Failure Mode: Failure to Start on Demand

- Test Data:

  - Number of Tests Per Month: 0
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 2
  - Number of Tests Per Refueling: 1
  - Total Number of Tests in Period: 17

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: SAFETY INJECTION PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 84

  Basis: Since the operation of these pumps is formally documented only during periodic operability verification tests, the pump service hours include only pump operating times during these tests. The pumps may be operated sporadically for the performance of auxiliary functions during normal plant operation, but these operating times are documented only in control room logs, and were not included in this study.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: RESIDUAL HEAT REMOVAL PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 65

  Basis: Although one residual heat removal pump is normally operating during cold shutdown periods, failures of these pumps are not reportable during cold shutdown, and these operating hours have been excluded from the data base. The pump service hours include only pump operating times during periodic operability verification tests.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: COMPONENT COOLING PUMP

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 7.4×10^4

  Basis: Although the component cooling system is normally in service under all plant operating conditions, the service hours for these pumps include two pumps operating continuously during noncold shutdown periods only, since failures of these pumps would be reported only during these periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: AUXILIARY COMPONENT COOLING PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 43

  Basis: Since the operation of these pumps is formally documented only during periodic operability verification tests, the pump service hours include only pump operating times during these tests.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: SERVICE WATER PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 7.40×10^4

  Basis: Since the technical specifications apply operability criteria to only the service water pumps aligned to the nuclear service header, the service hours for these pumps include the normal condition of two pumps operating on this header during noncold shutdown periods only, since failures would be reported only during these periods of operation.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
02/14/77	Service Water Pump 22	Bearing Failure
12/05/78	Service Water Pump 25	Bearing Failure

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: RECIRCULATION PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 3

  Basis: Since the operation of these pumps is formally documented only during periodic operability verification tests, the pump service hours include only pump operating times during these tests.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: CONTAINMENT SPRAY PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 54

  Basis: Since the operation of these pumps is formally documented only during periodic operability verification tests, the pump service hours include only pump operating times during these tests.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: MOTOR-DRIVEN AUXILIARY FEEDWATER PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 5,120

  Basis: Since the Auxiliary Feedwater system is normally in service during all periods of hot shutdown, the service hours for these pumps include both motor-driven pumps operating during approximately 80% of the total hot shutdown period hours (due to the allocation of one pump to two steam generators). The number of hours in hot shutdown was estimated from a review of the station power history summaries.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
12/15/77	Auxiliary Feedwater Pump 23	Motor Sparking

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: TURBINE-DRIVEN AUXILIARY FEEDWATER PUMP

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 640

  Basis: Since the turbine-driven auxiliary feedwater pump is generally operated only during startup and shutdown transient modes (due to its steam demand), the service hours for this pump include approximately 20% of the total hot shutdown period hours. The number of hours in hot shutdown was estimated from a review of the station power history summaries.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: CONTAINMENT FAN COOLERS

Failure Mode: Failure to Start on Demand

- Test Data:

  - Number of Tests Per Month: 0
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 5
  - Number of Tests Per Refueling: 0
  - Total Number of Tests in Period: 35

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test Review

- Failure Data Source: LERs

Component Type: CONTAINMENT FAN COOLERS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 7.4×10^4

  Basis: Although the fan cooler units are normally in service under all plant conditions, the service hours for these units conservatively include two fan coolers operating continuously during noncold shutdown periods only, since failures of these units would be reported only during these periods.

- Failure Data for Given Failure Mode*:

Date	Reported Failure	Cause
09/12/75	Fan Cooler Unit 22	Circuit Breaker Failure
02/08/79	Fan Cooler Unit 24	Defective Fan Bearing

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

*Failures do not include four items from 1/5/75, 7/30/75, 10/23/75, and 5/22/76 reporting the technical inoperability of seven fan cooler units due to their demister ΔP's exceeding acceptance criteria. Flow was maintained through these units in each of these instances, with only minimal degradation being noted. Replacement of the filter units upstream of the demisters has precluded recurrence of this problem.

Component Type: HEAT EXCHANGERS

Failure Mode: Rupture/Excessive Leakage

- Total Component Service Hours in Period: 1.48×10^5

  Basis: Data base includes service hours for the component cooling heat exchangers and both residual heat removal heat exchangers during noncold shutdown periods since leakage or rupture of these heat exchangers would be detectable and reportable during these operating periods.

- Failure Data for Given Failure Mode: No failures reported*

- Test Data Source: Unit operating status summary

- Failure Data Source: LERs

*The leaking of two tubes in component cooling heat exchanger 21 reported on 8/25/78 was excluded from the data base due to its inapplicability to this failure mode classification. Only failures resulting in significant inventory loss or degradation of heat exchanger cooling capabilities are included.

Component Type: HEAT EXCHANGERS

Failure Mode: Plugged - Tube Side

- Total Component Service Hours in Period: 7.4×10^4

  Basis: Data base includes service hours for the Component Cooling heat exchangers during noncold shutdown periods and one Residual Heat Removal heat exchanger during periodic testing periods, since plugging of these heat exchangers would be detectable and reportable during these operating periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Unit operating status summary

- Failure Data Source: LERs

Component Type: HEAT EXCHANGERS

Failure Mode: Plugged - Shell Side

- Total Component Service Hours in Period: 7.4×10^4

  Basis: Data base includes service hours for the component cooling heat exchangers during noncold shutdown periods and one residual heat removal heat exchanger during periodic testing periods, since plugging of these heat exchangers would be detectable and reportable during these operating periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Unit operating status summary

- Failure Data Source: LERs

Component Type: DIESEL GENERATORS

Failure Mode: Failure to Start on Demand

- Test Data:

  - Number of Tests Per Month: 3
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 3
  - Total Number of Tests in Period: 424*

- Failure Data for Given Failure Mode:**

Date	Reported Failure	Cause
08/08/74	Diesel Generator 21	Overcrank Without Starting
03/15/74	Diesel Generator 22	Unspecified
08/22/74	Diesel Generator 22	Output Voltage Relay Failure
10/24/74	Diesel Generator 22	Loose Wire on Output Voltage Relay

- Test Data Source: Test review and maintenance history summary

- Failure Data Source: LERs

*Since the technical specifications require immediate and daily operability verification for the redundant diesel generators whenever one diesel generator is removed from service for maintenance, station maintenance records were reviewed to determine the number of additional diesel generator starts for these verifications through the end of 1979. Only maintenance performed during noncold shutdown periods was included in this review. Of the 424 reported tests, 204 were performed as routine periodic operability tests and 220 were performed for operability verification during or following maintenance. Although the tests performed during maintenance are documented only in the control room operating logs and do not test the ability of the diesel generator to accept or run under load, the starting capabilities of the diesel engines are tested, and failures would be reported due to the technical specifications requirements for unit shutdown if more than one diesel generator is inoperable.

**Since the data base is developed for hardware failures attributable only to intrinsic diesel generator components or subsystems, data base excludes failure of diesel generator 22 reported on 4/7/74 due to failure cause from external support system (DC power) and failure of diesel generator 23 reported on 8/22/74 due to failure caused by human error. Although the only items included in the data base were reported during a 7-month period in 1974, the reported failures are representative of routinely observed independent component failures and, as such, must be included. Since the only failures reported are those which would have prevented a diesel generator from starting or operating under safeguards actuation conditions, any failures which may have been observed in addition to those reported should not have contributed to diesel generator failure for the event categories analyzed in this study.

Component Type: DIESEL GENERATORS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 204

  Basis: Since the diesel generators are normally operated under load only during the routine periodic operability verification tests, the service hours include only operating time during these testing periods. Tests performed for redundant diesel generator operability verification during maintenance periods do not include operation of the diesel generators under load and are, therefore, excluded from this data base. Routine operation of the diesel generators during unit startup and shutdown is similarly performed in an unloaded state, and is also excluded from these service hours.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: BUS FEED CIRCUIT BREAKERS

Failure Mode: Failure to Close on Demand

- Test Data:

  - Number of Tests Per Month: 4
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 12
  - Total Number of Tests in Period: 296*

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

*Data base includes only the operations of the diesel generator bus feed circuit breakers verified during routine periodic tests. Circuit breakers supplying power to individual components (e.g., 480V pumps) are not included in this data base, since the failures of these breakers are included in the specific component failure data bases. Operations of circuit breakers associated with routine unit startup and shutdown operations are not included.

Component Type: BUS FEED CIRCUIT BREAKERS

Failure Mode: Failure to Open on Demand

- Test Data:

  - Number of Tests Per Month: 4
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 12
  - Total Number of Tests in Period: 296*

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

*Data base includes only the operations of the diesel generator bus feed circuit breakers verified during routine periodic tests. Circuit breakers supplying power to individual components (e.g., 480V pumps) are not included in this data base, since the failures of these breakers are included in the specific component failure data bases. Operations of circuit breakers associated with routine unit startup and shutdown operations are not included.

Component Type: BUS FEED CIRCUIT BREAKERS

Failure Mode: Transfer Open

- Total Component Service Hours in Period: 4.44×10^5

  Basis: Data base includes service hours for the bus feed breakers during noncold shutdown periods only, since failures of these breakers would affect offsite power supply to the 480V essential power buses and would be reported under these operating conditions. Circuit breakers supplying power to individual components (e.g., 480V pumps) are not included in this data base, since the failures of these breakers are included in the specific component failure data bases. The breakers included in this data base are: 6.9 kV breakers ST5, ST6, (UT2 and UT2/ST5)*, (UT3 and UT3/ST6)*; and 480V breakers SS5, SS2, SS3, SS6, 5A, 2A, 3A, and 6A.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

*One of these breakers must be closed during all modes of unit operation

Component Type: AC POWER TRANSFORMERS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 1.85×10^5

  Basis: Data base includes service hours for the following transformers during noncold shutdown periods only, since failures of these transformers would affect offsite power supply to the 480V essential power buses and would be reported under these operating conditions. The transformers included in this data base are the station auxiliary transformer and the 6.9 kV/480V station service transformers SST5, SST2, SST3, and SST6.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: STATIC INVERTERS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 9.58×10^4

  Basis: Data base includes instrument bus inverter service hours during noncold shutdown operating periods only, since failures of these components would be reported only during these periods. Inverters 21 and 22 were included during the full period from 1973-1979; inverters 23 and 24 were installed in June 1978 and the service hours include these components after that date.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
10/22/78	One Inverter (Not Identified)	Unspecified

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: DC POWER BATTERIES

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 9.58×10^4

  Basis: Data base includes battery service hours during noncold shutdown operating periods only, since failures would be reported only during these periods. Batteries 21 and 22 were included during the full period from 1973-1979; batteries 23 and 24 were installed in June 1978 and the service hours include these components after that date.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: BATTERY CHARGERS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 9.58×10^4

  Basis: Data base includes battery charger service hours during noncold shutdown operating periods only, since failures would be reported only during these periods. Battery chargers 21 and 22 were included during the full period from 1973-1979; battery chargers 23 and 24 were installed in June 1978 and the service hours include these components after that date.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: DC CONTROL POWER TRANSFER DEVICES

Failure Mode: Failure to Transfer on Demand

- Test Data:

  - Number of Tests Per Month: 0
  - Number of Tests Per Quarter: 3
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 0
  - Total Number of Tests in Period: 75

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
04/07/74	Transfer Device for Diesel Generator 22	Unspecified

- Test Data Source: Test Review

- Failure Data Source: LERs

Component Type: DC CONTROL POWER TRANSFER DEVICES

Failure Mode: Transfer Open/Fail Open

- Total Component Service Hours in Period: 2.59×10^5

  Basis: Data base includes service hours for the seven devices supplying control power to buses 5A, 2A, 3A, and 6A, and diesel generators 21, 22, and 23 during noncold shutdown periods only, since failures would be reported only during these periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: BUSWORK

Failure Mode: Catastrophic Failure During Operation

- Total Component Service Hours in Period: 1.03×10^6

  Basis: The failure mode considered in this data base would result in complete failure of an electric power supply bus (i.e., failures more violent than transient short circuits or individual circuits failing open) and, as such, should be reported during all unit operating modes. Using this criterion, the data base includes service hours for the following buses under all unit operating conditions: 6.9 kV buses 5, 2, 3, and 6; 480 V buses 5A, 2A, 3A, and 6A; motor control centers 26A and 26B; instrument buses 21, 22, 23, and 24; DC power panels 21, 22, 23, and 24 (DC power panels 23 and 24 were installed in June 1978 and the service hours include these components after that date).

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

TABLE 1.5.1-1

INDIAN POINT 2 COLD SHUTDOWN PERIODS (1973-1979)

Date		Reason for Shutdown
1973:	01/01 - 05/22	Prior to Initial Criticality
	07/02 - 07/10	Service Water Valves
	09/07 - 09/21	Snubber Inspection
	09/28 - 10/01	Trip Testing
	10/12 - 12/31	Feedwater Line Break
1974:	01/01 - 01/25	Feedwater Line Break
	01/29 - 03/22	Feedwater Ring Modifications
	04/18 - 04/29	Maintenance Outage
	05/13 - 05/21	PRT Rupture Disc
	07/26 - 08/06	Maintenance Outage
	09/06 - 09/10	Maintenance Outage
	09/30 - 10/11	Maintenance Outage
	11/09 - 11/11	Maintenance Outage
	12/06 - 12/08	Maintenance Outage
1975:	01/01 - 01/05	Snubber Inspection
	01/31 - 02/02	Snubber Inspection
	02/28 - 04/04	Steam Generator Tube Leak and AVT Chemistry Modifications
	05/02 - 05/04	Feedwater Line Repair
	07/28 - 08/11	Reactor Coolant Pump Seals
	10/16 - 10/31	Generator Fault
	11/14 - 11/17	Control Rod Drive Fan Motors
1976:	01/04 - 01/06	RHR Suction Valve 731 Leak
	01/29 - 02/05	Incore System Repair
	03/30 - 09/27	Refueling Outage
	09/27 - 09/29	RHR Suction Valve 731 Leak
	10/29 - 12/11	Steam Generator Inspection
1977:	02/01 - 02/06	Seal Injection Weld Leak
	03/11 - 03/15	Seal Injection Weld Leak
	04/10 - 05/14	Steam Generator Inspection
	07/02 - 08/06	Reactor Coolant Pump Replaced
1978:	02/13 - 05/23	Refueling Outage
	09/15 - 10/06	Reactor Coolant Pump Seal Repair
	11/23 - 12/03	Seal Injection Weld Leak
1979:	06/16 - 09/11	Refueling Outage
	12/02 - 12/8	Letdown Line Relief Valve Leak

TABLE 1.5.1-2

INDIAN POINT 2 COMPONENT PERIODIC TESTS (1973-1979)

Testing Frequency	Number of Tests Performed in Study Period
Monthly*	65
Quarterly**	25
Annually	7
Refueling	3

*During power operation.
**During any calendar quarter in which the unit was not in continuous cold shutdown.

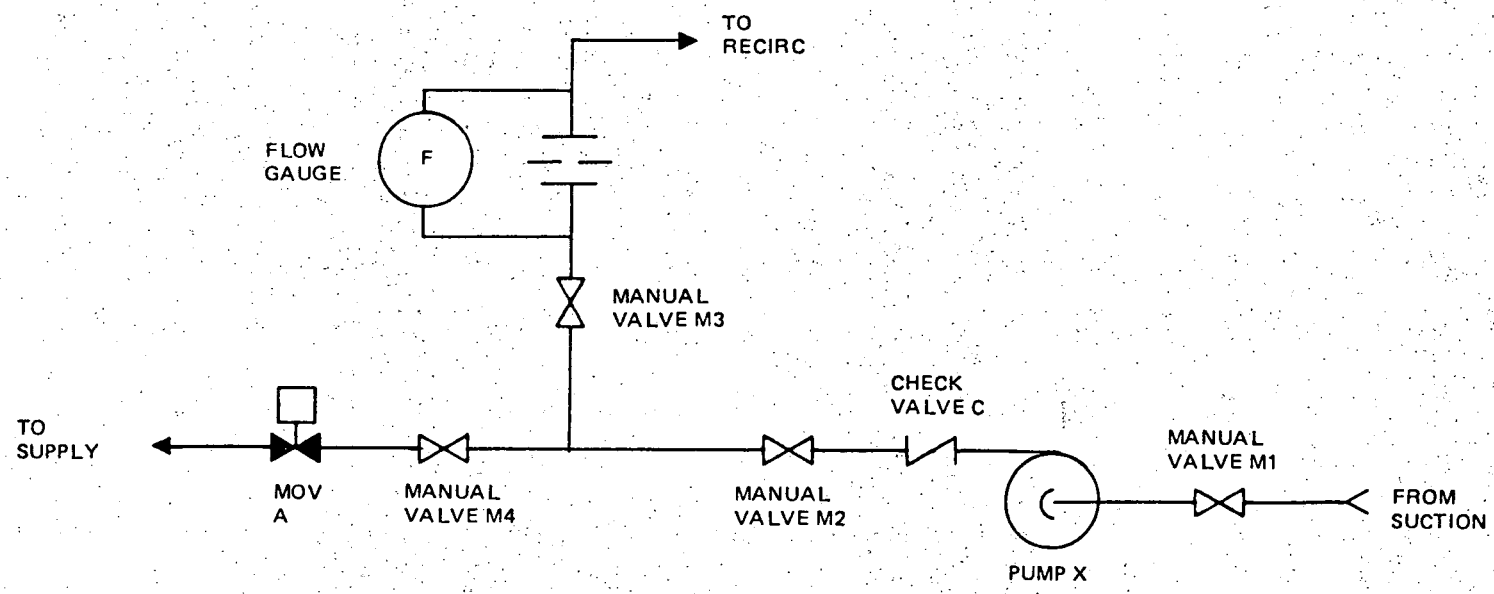

Figure 1.5.1-1. Indian Point 2 Flow Test Data Example System

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1.5.1.2 Generic and Updated Component Failure Data

This appendix discusses the generic data, references their sources and shows the updated plant data, specialized using Bayes' theorem.

The derivation of prior distributions for the failure rates involves an extensive literature survey and the use of judgment. Table 1.5.1-3 identifies some of the key sources. For many components a single source does not exist which has all the data required for this study in a form that would allow an unambiguous determination of the prior distribution. For example, it is not always specified what failure modes are represented, the environments for which the data are applicable, etc.

Most of the generic data on valves, pumps and diesel generators were obtained from the NUREG data summaries (References 1.5.1-1, 1.5.1-2, and 1.5.1-3). Generic data for heat exchangers were obtained from NPRDS (Reference 1.5.1-4). This study used the mean values reported in the NUREGs as the mean values of the generic population and the ratio of the 95th to the 5th percentile reported in the Reactor Safety Study (Reference 1.5.1-5) as the ratio of the 80th to the 20th percentiles of the population variability curves. The lognormal curves from the RSS are regarded as the results of experiments on populations. They are frequency distributions that represent the variability stemming from different manufacturers, different models, different operating and maintenance conditions, and the random fluctuations occurring in presumably identical components. For example, if a large population of valves, pumps, or diesel generators were tested and if the frequency of specific failures were plotted, that plot would turn out to be a lognormal curve.

Data for electronic, electrical, and sensing components were obtained from IEEE STD-500 (Reference 1.5.1-6). The reported values were mainly synthesized from the opinions of approximately 200 experts (a form of the Delphi procedure was used). Each expert reported a low, recommended, and high value of the failure rate under normal conditions and a maximum value which would be applicable under all conditions (including abnormal ones). The estimates were pooled using geometric averaging techniques, e.g.,

$$\hat{\lambda}_{MAX} = \left[\prod_{i=1}^{n} \hat{\lambda}_{MAX,i} \right]^{1/n} \qquad (1.5.1\text{-}1)$$

This method of averaging was judged to be a better representation of the expert estimates which were often given in terms of negative powers of 10. In effect, the usual arithmetic averages of the exponents were used.

The IEEE STD-500 does not recommend a distribution. The method of averaging, however, indicates that it would be appropriate to assume a lognormal distribution. For this analysis, the "recommended" value was

used as the median and the "maximum" value as the 80th percentile of the population variability curve. These two values were then used to generate the 20th percentile.

In some cases for which there was no applicable data in the NUREGs or in IEEE STD-500, the RSS 5th and 95th percentile values were used as the 20th and 80th percentiles of the population variability curve.

The historical plant specific data listed in Section 1.5.1 for the number of failures and the number of demands or total service time was updated using generic prior distributions to obtain a specialized posterior distribution. The methodology for performing this specialization is discussed in the main report. The results are listed in Table 1.5.1-4, which contains the following information:

- Component description and failure mode.
- Plant evidence (historical plant data).
- Updated plant data (failure rate means and variances for posterior distribution).
- Generic prior distribution used to update the plant evidence and the sources of the generic data.

TABLE 1.5.1-3

INDIAN POINT 2 KEY GENERIC RELIABILITY DATA SOURCES

Item	Key Data Sources	Reference
Electrical	IEEE STD-500	1.5.1-6
Electronic	IEEE STD-500	1.5.1-6
Instruments	WASH-1400, IEEE STD-500	1.5.1-5, 1.5.1-6
Valves	NUREG/CR-1363, WASH-1400	1.5.1-1, 1.5.1-5
Pumps	NUREG/CR-1205, WASH-1400	1.5.1-2, 1.5.1-5
Diesel Generators	NUREG/CR-1362, WASH-1400	1.5.1-3, 1.5.1-5
Mechanical	NPRDS, WASH-1400	1.5.1-4, 1.5.1-5

TABLE 1.5.1-4

INDIAN POINT 2 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
1) System: All Component Type: Manual Valves, Motor-Operated Valves Failure Mode: Transfer Closed	0	6.0(6) hours	7.40(-8) /hour	5.89(-15) /(hour)^2	[2.8(-8)] /hour	[2.8(-7)] /hour	W-1400. Fail to remain open. Plugged. λ5 = 3(-5)/demand; λ95 = 3(-4)/demand. Used 1 demand/45 days to convert to hours. λ5 = 2.8(-8)/hour; λ95 = 2.8(-7)/hour.
2) System: All Component Type: Manual Valves Failure Mode: Transfer Open/Excessive Leakage Through Valve	0	7.03(2) hours	1.99(-8) /hour	1.83(-13) /(hour)^2	2.0(-8) /hour	100	N-1363. Manual valves. External leakage PWRs X = 2(-8)/hour. W-1400. MOVs. External leakage/rupture. λ5 = 1(-9)/hour; λ95 = 1(-7)/hour.
3) System: All Component Type: Check Valves Failure Mode: Failure to Open on Demand	0	1.444(3) demands	7.02(-5) /demand	1.09(-8) /(demand)^2	1.0(-4) /demand	10	N-1363. Check valves. Fail to open. PWRs X = 1(-4)/demand. W-1400. Check valves. Failure to open. λ5 - 3(-5)/demand; λ95 = 3(-4)/demand.
4) System: All Component Type: Check Valves Failure Mode: Failure to Seat/Excessive Reverse Leakage	1	4.44(5) hours	9.20(-7) /hour	1.03(-12) /(hour)^2	5.0(-7) /hour	10	N-1363. Check valves. Internal leakage PWRs X = 5(-7)/hour. W-1400. Check valves. Reverse leak. λ5 = 1(-7)/hour; λ95 = 1(-6)/hour.
5) System: All Component Type: Relief/Safety Valves Failure Mode: Premature Opening or Leakage	1	3.01(5) hours	2.56(-6) /hour	4.81(-12) /(hour)^2	3.0(-6) /hour	10	N-1363. PWR safety valves. Premature opening. X = 3(-6)/hour. W-1400. Relief valves (all Rx types). Premature opening. λ5 = 3(-6)/hour; λ95 = 3(-5)/hour.
6) System: All Component Type: Motor-Operated Valves Failure Mode: Failure to Operate on Demand	3	1.261(3) demands	2.32(-3) demand	1.19(-6) /(demand)^2	4.0(-3) /demand	10	N-1363. PWR - Remote operated plus MOV. No command faults. Fail to operate. X = 4(-3)/demand. W-1400. Failed to operate. λ5 = 3(-4)/demand; λ95 = 3(-3)/demand.

NOTE: 1.23(4) indicates 1.23×10^4
N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.5.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.5.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.5.1-3)

NPRDS: 1976, page 34 (Reference 1.5.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.5.1-5)
IEEE 500: 1977 (Reference 1.5.1-6)

TABLE 1.5.1-4 (continued)

INDIAN POINT 2 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
7) System: All Component Type: Motor-Operated Valves Failure Mode: Transfer Open/Excessive Leakage Through Valve	0	8.18(2) hours	9.65(-8) /hour	3.75(-12) /(hour)^2	1.0(-7) /hour	100	N-1363. PWR Remote + MOV - No command fault. External leakage. X = 1(-7)/hour. W-1400. MOVs External leakage/rupture. λ5 = 1(-9)/hour; λ95 = 1(-7)/hour.
8) System: All Component Type: Air-Operated Valves Failure Mode: Failure to Operate on Demand	1	1.05(3) demands	7.49(-4) /demand	4.01(-7) /(demand)^2	9.0(-4) /demand	10	N-1363 PWR AOV Fail to operate. No command faults. X = 9(-4)/demand. W-1400. AOV fails to operate. λ5 = 1(-4)/demand; λ95 = 1(-3)/demand.
9) System: All Component Type: Air-Operated Valves Failure Mode: Transfer Closed	0	4.44(5) hours	1.71(-7) /hour	7.29(-14) /(hour)^2	[2.8(-8)] /hour	[2.8(-7)] /hour	W-1400. AOV Plug. Failure to remain open. Used 1 demand/45 days to convert to 1 hr. λ5 = 3(-5) = 2.8(-8)/hour; λ95 = 3(-4) = 2.8(-7)/hour.
10) System: All Component Type: Air-Operated Valves Failure Mode: Transfer Open/Excessive Leakage	0	3.7(4) hours	7.30(-8) /hour	2.83(-13) /(hour)^2	1.0(-7) /hour	100	N-1363. AOV External leakage X = 1(-7)/hour. W-1400. AOV External leakage/rupture. λ5 = 1(-9)/hour; λ95 = 1(-7)/hour.
11) System: All Component Type: Pumps - Motor-Driven Failure Mode: Failure to Start on Demand	7	7.93(2) demands	6.41(-3) /demand	7.78(-6) /(demand)^2	5.0(-4) /demand	10	N-1205. Standby system. Does not start. No command faults. X = 5(-4)/demand. W-1400. Electric motor. Failure to start. λ5 = 1(-4)/demand; λ95 = 1(-3)/demand.
12) System: Auxiliary Feedwater Component Type: Turbine-Driven Auxiliary Feedwater Pump Failure Mode: Failure to Start on Demand	0	1.7(1) demands	2.01(-3) /demand	2.50(-5) /(demand)^2	4.0(-3) /demand	100	N-1205. Standby System. No command faults. Does not start. X = 4(-3)/demand. λ80/λ20 based on engineering judgment.

NOTE: 1.23(4) indicates 1.23 x 10^4
N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.5.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.5.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.5.1-3)

NPRDS: 1976, page 34 (Reference 1.5.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.5.1-5)
IEEE 500: 1977 (Reference 1.5.1-6)

TABLE 1.5.1-4 (continued)

INDIAN POINT 2 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
13) System: Safety Injection Component Type: Safety Injection Pumps Failure Mode: Fail During Operation	0	8.4(1) hours	1.59(-5) /hour	1.61(-8) /(hour)^2	2.0(-5) /hour	100	N-1205. Alternating System. Does not operate given start. X = 2(-5)/hour. W-1400. Pump (w/o motor). Failure to run. λ5 = 3(-6)/hour; λ95 = 3(-4)/hour.
14) System: Residual Heat Removal Component Type: Residual Heat Removal Pumps Failure Mode Fail During Operation	0	6.5(1) hours	1.63(-5) /hour	1.87(-8) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
15) System: Component Cooling Component Type: Component Cooling Pumps Failure Mode: Fail During Operation	0	7.4(4) hours	2.76(-6) /hour	1.59(-11) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
16) System: Component Cooling Component Type: Auxiliary Component Cooling Pumps Failure Mode: Fail During Operation	0	4.3(1) hours	1.68(-5) /hour	2.76(-8) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
17) System: Service Water Component Type: Service Water Pumps Failure Mode: Fail During Operation	2	7.4(4) hours	1.52(-5) /hour	2.09(-10) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
18) System: Recirculation Component Type: Recirculation Pumps Failure Mode: Fail During Operation	0	3 hours	1.95(-5) /hour	1.60(-7) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
19) System: Containment Spray Component Type: Containment Spray Pumps Failure Mode: Fail During Operation	0	5.4(1) hours	1.65(-5) /hour	2.18(-8) /(hour)^2	2.0(-5) /hour	100	Same as Number 13

NOTE: 1.23(4) indicates 1.23 x 10^4
N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.5.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.5.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.5.1-3)

NPRDS: 1976, page 34 (Reference 1.5.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.5.1-5)
IEEE 500: 1977 (Reference 1.5.1-6)

TABLE 1.5.1-4 (continued)

INDIAN POINT 2 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated Mean	Updated Variance	Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
20) System: Auxiliary Feedwater Component Type: Motor Driven Auxiliary Feedwater Pumps Failure Mode: Fail During Operation	1	5.12(3) hours	6.54(-5) /hour	1.05(-8) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
21) System: Auxiliary Feedwater Component Type: Turbine Driven Auxiliary Feedwater Pump Failure Mode: Fail During Operation	0	6.4(2) hours	1.15(-5) /hour	3.99(-9) /(hour)^2	2.0(-5) /hour	100	Same as Number 13. Turbine-driven pump failure during operation similar to motor-driven pump during operation.
22) System: Containment Fan Coolers Component Type: Containment Fan Coolers Failure Mode: Failure to Start on Demand	0	3.5(1) demands	7.26(-4) /demand	1.82(-6) /(demand)^2	[1.0(-4)] /demand	[1.0(-3)] /demand	W-1400. Electric motor. Failure to run. λ5 = 1(-4)/demand; λ95 = 1(-3)/demand.
23) System: Containment Fan Coolers Component Type: Containment Fan Coolers Failure Mode: Fail During Operation	2	7.4(4) hours	4.08(-5) /hour	3.60(-10) /(hour)^2	[1(-4)] /hour	[1(-2)] /hour	W-1400. Electric motor. Failure to run. Extreme environment. λ5 = 1(-4)/hour; λ95 = 1(-2)/hour.
24) System: All Component Type: Heat Exchangers Failure Mode: Rupture/Excessive Leakage	0	1.48(5) hours	8.42(-7) /hour	1.94(-12) /(hour)^2	4.56(-6) /hour	100	NPRDS page 34 X = 4.56(-6)/hour. λ80/λ20 based on engineering judgment.
25) System: All Component Type: Heat Exchangers Failure Mode: Plugged (Tube Side)	0	7.4(4) hours	ε	ε	ε	ε	Negligibly small failure rate. Estimated on the basis of engineering judgment.
26) System: All Component Type: Heat Exchangers Failure Mode: Plugged (Shell Side)	0	7.4(4) hours	ε	ε	ε	ε	Negligibly small failure rate. Estimated on the basis of engineering judgment.

NOTE: 1.23(4) indicates 1.23 x 10^4
N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.5.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.5.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.5.1-3)

NPRDS: 1976, page 34 (Reference 1.5.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.5.1-5)
IEEE 500: 1977 (Reference 1.5.1-6)

TABLE 1.5.1-4 (continued)

INDIAN POINT 2 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
27) System: Diesel Generators Component Type: Diesel Generators Failure Mode: Failure to Start on Demand	4	4.24(2) demands	1.29(-2) /demand	4.15(-5) /(demand)^2	3.0(-2) /demand	10	N-1362. Monthly testing. Diesel generator fails to start. No command faults. X = 3(-2)/demand. W-1400. Diesel generator. Failure to start. λ5 = 1(-2)/demand; λ95 = 1(-1)/demand.
28) System: Diesel Generators Component Type: Diesel Generators Failure Mode: Fail During Operation	0	2.04(2) hours	9.37(-4) /hour	3.37(-6) /(hour)^2	2.0(-2) /hour	100	N-1362. Monthly testing. Diesel generator. Does not continue to run. No command faults. X = 2(-2)/hour. W-1400. Diesel generator. Failure to run. λ5 = 3(-4)/hour; λ95 = 3(-2)/hour.
29) System: AC Electric Power Component Type: Bus Feed Breakers Failure Mode: Failure to Close on Demand	0	2.96(2) demands	2.46(-5) /demand	1.84(-8) /(demand)^2	[1.0(-7)] /demand	[1.0(-5)] /demand	IEEE-500 Interior design. AC breaker fails to close. Page 148. Rec = 1(-6)/demand; Max = 1(-5)/demand.
30) System: AC Electric Power Component Type: Bus Feed Breakers Failure Mode: Failure to Open on Demand	0	2.96(2) demands	6.36(-4) /demand	2.14(-6) /(demand)^2	[2.27(-5)] /demand	[2.27(-3)] /demand	IEEE-500. Interior design. AC breaker fails to open. Page 148. Rec = 2.27(-4)/demand; Max = 2.27(-3)/demand.
31) System: AC Electric Power Component Type: Bus Feed Breakers Failure Mode: Transfer Open	0	4.44(5) hours	4.81(-7) /hour	8.71(-13) /(hour)^2	[3.08(-9)] /hour	[6.0(-7)] /hour	IEEE-500. Interior design. AC breaker spurious operation. Page 148. Rec = 4.3(-8)/hour; Max = 6(-7)/hour.
32) System: AC Electric Power Component Type: Transformers, Dry Type, 3-Phase Failure Mode: Fail During Operation	0	1.85(5) hours	7.63(-7) /hour	1.14(-12) /(hour)^2	[1.44(-7)] /hour	[1.51(-6)] /hour	IEEE-500. Transformers (601V-15kV). All modes. Pg. 300. Rec = 4.67(-7)/hour; Max = 1.51(-6)/hour.

NOTE: 1.23(4) indicates 1.23 x 10^4
N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.5.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.5.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.5.1-3)

NPRDS: 1976, page 34 (Reference 1.5.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.5.1-5)
IEEE 500: 1977 (Reference 1.5.1-6)

TABLE 1.5.1-4 (continued)

INDIAN POINT 2 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
33) System: AC Electric Power Component Type: Inverters Failure Mode: Fail During Operation	1	9.58(4) hours	1.55(-5) /hour	2.20(-10) /(hour)^2	[3.0(-7)] /hour	[3.0(-5)] /hour	W-1400. Solid state device. High power application. Fails to function. λ5 = 3(-7)/hour; λ95 = 3(-5)/hour.
34) System: DC Electric Power Component Type: Batteries Failure Mode: Fail During Operation	0	9.58(4) hours	8.21(-8) /hour	5.82(-14) /(hour)^2	[4.95(-9)] /hour	[8.74(-8)] /hour	IEEE-500. Batteries-lead-acid. Page 104. Stationary types for float service. Catastrophic failure. Rec = 2.08(-8)/hour; Max = 8.74(-8)/hour.
35) System: DC Electric Power Component Type: Battery Chargers Failure Mode: Fail During Operation	0	9.58(4) hours	2.01(-6) /hour	2.30(-11) /(hour^2	[1.78(-8)] /hour	[1.25(-4)] /hour	IEEE-500. Rectifiers. Stationary type. All modes. Page 90. Rec = 1.49(-6)/hour; Max = 1.25(-4)/hour.
36) System: DC Electric Power Component Type: Automatic Transfer Devices (Switches) Failure Mode: Failure to Transfer on Demand	1	7.50(1) demands	2.71(-6) /demand	6.91(-12) /(demand)^2	[5.0(-7)] /demand	[2.0(-6)] /demand	IEEE-500. Bistable. All modes. Page 483. Rec = 1.0(-6)/demand; Max = 2.0(-6)/demand.
37) System: All Electric Power Component Type: Bus, Metal-Enclosed Failure Mode: Open Circuit	0	1.03(6) hours	2.80(-8) /hour	6.93(-15) /(hour)^2	[6.44(-10)] /hour	[2.74(-8)] /hour	IEEE-500. Metal-enclosed bus. Open Circuit. Page 188. Rec = 4.2(-9)/hour; Max = 2.74(-8)/hour.
38) System: All Electric Power Component Type: Manual Transfer Devices (Switches) Failure Mode: Transfer Open	*	*	ε	ε	ε	ε	Negligibly small failure rate. Estimated on the basis of engineering judgment.

*Generic data was used to calculate the mean and variance. No plant data was used.
NOTE: 1.23(4) indicates 1.23 x 10^4
N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.5.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.5.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.5.1-3)

NPRDS: 1976, page 34 (Reference 1.5.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.5.1-5)
IEEE 500: 1977 (Reference 1.5.1-6)

TABLE 1.5.1-4 (continued)

INDIAN POINT 2 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
39) System: Reactor Protection Component Type: Control Cable Failure Mode: Line-to-Line Short	*	*	3.22(-6) /hour	8.96(-11) /(hour)^2	[2.93(-7)] /hour	[3.68(-6)] /hour	IEEE-500. Copper conductor. Line-to-line short. Page 524. Rec = 1.038(-6)/hour; Max = 3.675(-6)/hour.
40) System: Reactor Protection Component: Control Cable Failure Mode: Line-to-Ground Short	*	*	7.52(-6) /hour	4.88(-10) /(hour)^2	[6.84(-7)] /hour	[8.58(-6)] /hour	IEEE-500. Copper conductor. Line-to-ground short. Page 524. Rec = 2.422(-6)/hour; Max = 8.575(-6)/hour.
41) System: All Electric Power Component Type: Trip relay Failure Mode: Fails to Open on Demand	*	*	6.28(-6) /demand	2.49(-11) /(demand)^2	[2.73(-6)] /demand	[8.85(-6)] /demand	IEEE-500. Auxiliary relays. Fail to open. Page 164. Rec = Not given. An RF = $\sqrt{10}$ was used based on W-1400. Max = 8.85(-6)/demand.
42) System: All Pipes (<3" In Diameter) Component Type: Pipe Section Failure Mode: Ruptures/Plugs	*	*	8.60(-9) /(hour)	6.00(-15) /(hour)^2	λ5 3(-11) /hour	λ95 3(-8) /hour	W-1400. Pipes (<3") High quality section as defined in W-1400. λ5 = 3(-11)/hour; λ95 = 3(-8)/hour.
43) System: All Pipes (>3" In Diameter) Component Type: Pipe Section Failure Mode: Ruptures/Plugs	*	*	8.60(-10) /(hour)	6.00(-17) /(hour)^2	λ5 (3-12) /hour	λ95 3(-9) /hour	W-1400. Pipes (>3") High quality section as defined in W-1400. λ5 = 3(-12)/hour; λ95 = 3(-9)/hour.
44) System: Auxiliary Feedwater Component Type: Condensate Storage Tank Failure Mode:	*	*	8.48(-10) /(hour)	5.10(-17) /(hour)^2	λ50 1(-10) /hour	RF 30	W-1400. Fault tree event PTKCONDF. Table II 5-5. Page II-207. λ50 = 1(-10)/hour; RF = 30.

*Generic data was used to calculate the mean and variance. No plant data was used.
NOTE: 1.23(4) indicates 1.23 x 10^4
N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.5.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.5.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.5.1-3)

NPRDS: 1976, page 34 (Reference 1.5.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.5.1-5)
IEEE 500: 1977 (Reference 1.5.1-6)

TABLE 1.5.1-4 (continued)

INDIAN POINT 2 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
45) System: Reactor Protection Component Type: Breakers Failure Mode: Fail to Open on Demand	0	440 demands	4.67(-4) /demand	8.51(-7) /(demand)^2	[2.97(-5)] /demand	[2.97(-3)] /demand	IEEE-500. Indoor design. AC breakers. Catastrophic failure Page 148. Rec = 2.97(-4)/demand; Max = 2.97(-3)/demand.
46) System: Safeguards Actuation Component Type: Fuse, DC Power Failure Mode: Opens Prematurely	~~1~~*	*	8.32(-7) /hour	1.08(-9) /(hour)^2	[2.15(-9)] /hour	[2.05(-7)] /hour	IEEE-500. Fuse. DC power. Opens prematurely. Page 193. Rec = 2.1(-8)/hour; Max = 2.05(-7)/hour.
47) System: Safeguards Actuation Component Type: Master Relay. Latch and Reset Coil Included Failure Mode: Fails to Energize on Demand	*	*	1.15(-5) /demand	3.38(-9) /(demand)^2	[4.92(-7)] /demand	[1.03(-5)] /demand	IEEE-500. Relay. Fails to close. Page 154. Rec = 2.25(-6)/demand; Max = 1.03(-5)/demand.
48) System: Safeguards Actuation Component Type: Relay - General Failure Mode: Contacts Open	*	*	2.43(-7) /hour	3.26(-13) /(hour)^2	[3.0(-8)] /hour	[3.0(-7)] /hour	W-1400. Relay. Normally closed contacts open. λ5 = 3(-8)/hour; λ95 = 3(-7)/hour.
49) System: Safeguards Actuation Component Type: Bistable Switch Failure Mode: Failure to Open on Demand	*	*	3.88(-7) /demand	1.47(-13) /(demand)^2	[1.38(-7)] /demand	[5.52(-7)] /demand	IEEE-500. Bistable switch. Failed to function when signaled. Page 483. Rec = 2.76(-7)/demand; Max = 5.52(-7)/demand.
50) System: Safeguards Actuation Component Type: Transmitters Failure Mode: Fail to Provide Proper Output	*	*	1.66(-6) /hour	6.28(-12) /(hour)^2	λ50 9.18(-7) /hour	RF 6	IEEE-500. Transmitter. Catastrophic failure. Page 428. Rec = 9.18(-7)/hour; RF = 6 = $\sqrt{max/low}$
51) System: Safeguards Actuation Component Type: Switches Failure Mode: Contacts Short Across	*	*	4.28(-7) /hour	3.36(-10) /(hour)^2	[1.0(-9)] /hour	[1.0(-7)] /hour	W-1400. Switches. Contacts short across. λ5 = 1(-9)/hour; λ95 = 1(-7)/hour.

*Generic data was used to calculate the mean and variance. No plant data was used.

NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.5.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.5.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.5.1-3)

NPRDS: 1976, page 34 (Reference 1.5.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.5.1-5)
IEEE 500: 1977 (Reference 1.5.1-6)

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1.5.1.3 Generic and Updated Component Maintenance Data

Maintenance activities which remove components from service and alter the normal configurations of mechanical systems can provide a significant contribution to the overall unavailability of those systems. Although plant operating and maintenance records provide a source of detailed information for specific maintenance events, a review of these records indicates that the site specific information alone provides a relatively small and inconclusive data base for many of the standby safeguards equipment systems of specific concern in this study. As an extension of the general methodology discussed in Section 1.5.1 for component failure data, the techniques of Bayesian specialization were applied to the available site specific component maintenance data. This was done to develop a more meaningful representation of the state of maintenance at Indian Point Unit 2 than would be available from either the site specific or generic information alone.

1.5.1.3.1 Data Base Development Methodology

1.5.1.3.1.1 Data Base Definition

1.5.1.3.1.1.1 General Considerations. The only maintenance activities included in this data base are those performed during noncold shutdown periods which place a system in a degraded condition with respect to the performance of safeguards functions analyzed in this study. Only noncold shutdown (i.e., power operation or hot shutdown) periods are included for the following reasons:

- Operating, maintenance, and system testing procedures and practices are modified significantly when the plant enters the cold shutdown condition.
- The technical specifications operability criteria for safety systems and components generally specify cold shutdown as the condition in which inoperability restrictions do not apply.
- The plant operating modes of primary concern in this study are power operation and, in some cases, hot shutdown (i.e., noncold shutdown modes).
- Specific plant shutdown and startup times were most readily available for periods when the plant was placed in cold shutdown.

Each maintenance event was analyzed for its effects on system operability by examining the restrictions or abnormal configurations of the system during the maintenance. For example, given maintenance event which required that a pump to be either mechanically or electrically isolated was included in the data base because the pump was not available for service. However, an event during which only the motor operator for a valve was deenergized, with the valve remaining in the required position for safeguards actuation, was not included because the activity resulted in no impairment of the valve's ability to permit flow

under emergency conditions. (The activity would have been included if the valve had been deenergized in the nonsafeguards position.)

In general, maintenance performed on valves has not been included as a distinct category within this data base. The most common forms of valve maintenance performed during noncold shutdown periods are packing adjustment and repairs of the control circuitry and valve operators for motor-operated and air-operated valves. Nearly all these maintenance activities are performed with the associated valve remaining in its safeguards position and are thus inapplicable to this data base. Because of the time criteria for unit shutdown imposed by the plant's technical specifications, major valve maintenance involving full packing replacement or repairs of the valve body and internals is generally postponed, if possible, until the unit is placed in the cold shutdown condition either for refueling or for a planned maintenance outage. Repairs which cannot be postponed until a planned shutdown and which affect the operability of an entire system require the unit to be shut down. Therefore, they are also excluded from this data base. (The maintenance event records reviewed at Indian Point Unit 2 fully support these general practices with respect to individual valve maintenance events.) Maintenance on valves which affect only portions of a safety system may be performed during noncold shutdown periods within the component and system inoperability limitations imposed by the plant's technical specifications. However, in the majority of these cases, the maintenance activity requires the removal from service of the pump in the flow path of which the valve is a part (e.g., for pump suction protection or for personnel protection at the pump's discharge) and is thus indistinguishable in application from maintenance performed on the pump itself. Although valve repairs generally require less time to complete than pump repairs, the infrequent nature of individual valve maintenance and the inability to precisely differentiate between maintenance events for pumps and valves in the site specific data records justify the inclusion of valve maintenance with the associated pump maintenance data base. Therefore, in this study, maintenance performed on a "pump" is defined as any maintenance performed on any component in the unique flow path of that pump which requires removing the pump from service. Individual valve maintenance events are not considered as a distinct category.

Most of the maintenance on the plant's electric power system, with the exception of the diesel generators, is performed during cold shutdown periods when the electrical load on the system is reduced and the technical specifications inoperability criteria are relaxed. Most of the maintenance during noncold shutdown periods is performed on individual bus circuit breakers. During these infrequent events, a spare circuit breaker is installed in the maintained breaker's cubicle thereby maintaining the operability of the affected power supply and excluding this type of maintenance from the data base. Maintenance performed on other components of the electric power system is similarly excluded from the data base because of the extremely infrequent nature of these events, the operability restrictions imposed by the technical specifications, and the ability to maintain the associated power supply

buses energized through redundant supply circuits and manual bus interconnections.

Based on these criteria, the component maintenance data base for Indian Point Unit 2 was developed only for noncold shutdown periods and applies only to the diesel generators and the specific pumps (and components in their associated flow paths) analyzed in this study.

1.5.1.3.1.1.2 Frequency of Maintenance. The frequency at which maintenance is performed on a given component during noncold shutdown periods generally depends on three major factors:

1. The normal service duty of the component and its associated failure rate necessitate unscheduled maintenance events for the repair of gross failures or major component degradation.

2. Regularly scheduled plant preventive maintenance and inspection programs may be instituted for certain components.

3. The duration of component inoperability allowed by the plant's technical specifications affects the frequency of maintenance.

The precise impact of the technical specifications on maintenance frequency is highly dependent on the way in which the plant's maintenance personnel compensate for the imposed time limitations and may vary widely between plants. A relatively short inoperability limit (24 hours, for example) may result in either a relatively high frequency of very short duration events during which maintenance personnel perform very minor repairs and preventive maintenance, or a low frequency of maintenance determined by the component's failure rate under conditions of minimal preventive maintenance. In the first case, plant personnel try to avoid events of long duration by scheduling many controlled events of shorter duration. In the second case, personnel are willing to accept infrequent failures requiring unit shutdown to avoid frequent events during which the possibility of imposed shutdown exists because of unforeseen delays. Whether the first or the second (or some intermediate) case prevails at a given plant depends on that plant's general operating and maintenance practices and thus cannot be easily generalized.

1.5.1.3.1.1.3 Duration of Maintenance. As applied in this data base, the duration of a maintenance event includes the entire time during which the affected component is unavailable for operation. This period is defined from the time when the component is originally isolated or otherwise removed from service to the time when the component is returned to service in an operable state. In many cases, it may be only weakly dependent on the actual time required for maintenance personnel to make the repairs. Thus, the duration of a maintenance event performed during noncold shutdown periods generally depends on four major factors:

1. The magnitude of the failure determines the minimum time required for maintenance personnel to make repairs and may affect the complexity and duration of the tagout and return to service operations.

2. The availability of maintenance personnel affects the time between component failure and initiation of repairs and also affects the duration of the repair job (e.g., if maintenance personnel are regularly available from 7 a.m. until 11 p.m., repairs cannot be quickly initiated during the 8-hour off shift).

3. General plant maintenance scheduling and priorities influence the sequence in which components are repaired and the relative effort expended toward repairing a given component within a fixed time period.

4. The duration of component inoperability allowed by the plant's technical specifications directly affects the relative priorities assigned to certain maintenance events.

The availability of personnel and the priorities in effect at a given plant often determine the maintenance duration (as opposed to the relatively ideal case in which duration is directly proportional to the complexity of repair). The impact of the technical specifications on the relative priorities assigned to maintenance activities cannot be overemphasized. A major repair of a component that is allowed to be inoperable for a maximum of 72 hours will often be completed in less time than a minor adjustment of a component that is allowed to be inoperable indefinitely, even if both components are parts of engineered safeguards systems (however, with apparently different importance or available redundancy, as indicated by the differing technical specifications limitations). Because of these factors and because each plant has its own unique personnel and procedural limitations, it is extremely difficult to generalize maintenance duration data to several plants, even if it is applied to otherwise physically identical components.

1.5.1.3.1.2 Data Base Specialization. Detailed site specific component maintenance data was obtained by an extensive review of the Indian Point Unit 2 operating and maintenance records. This review provided nearly 3-1/2 years of specific component maintenance information. However, because maintenance is infrequently performed on standby safety systems components during noncold shutdown periods, this site specific data was in many cases sparse and relatively inconclusive (because of the high variability exhibited by the small sample of events). Because of these generally small, variable sample sizes, the techniques of Bayesian specialization, as described in the main report, were used to integrate the site specific information with generalized prior data distributions. Thus, an expression for the state of knowledge about maintenance activities at Indian Point Unit 2 was developed which applies the correct weighting factors to both the detailed evidence and the available prior information.

As discussed in Sections 1.5.1.3.1.1.2 and 1.5.1.3.1.1.3, the frequency and duration of maintenance events are determined in a relatively independent manner through the combined effects of numerous factors (the technical specifications allowed duration of inoperability is one important common factor). Both frequency and duration information are necessary to evaluate the impact of maintenance activities on the systems analyzed in this study. The frequency of maintenance defines the rate at which components are removed from service and is a basis for evaluating recovery factors and human interactions; the duration and frequency combined determine the component unavailability to be applied in the quantification of system hardware failures during maintenance activities. Because the frequency and duration of maintenance are not directly related, a separate specialized distribution was developed for each of these parameters as it applies to each of the components included in the data base.

The prior distributions for maintenance event frequency were specialized using the Indian Point Unit 2 maintenance data by the direct application of Bayes' theorem, as described in the methodology discussion in the main report.

The general principles of Bayesian specialization apply equally to the maintenance duration data. However, the data obtained from the plant exhibits wide variability in the observed duration of the maintenance performed on each component. Because of the relatively small data sample for most components, this variability leads to a significant uncertainty about the mean duration to be applied in determining component unavailability due to maintenance. To correctly include this uncertainty about the mean duration, an extension of the specialization process described for component failure and maintenance frequency data was developed and applied to the site specific duration data. The results of this process were distributions of the mean duration of maintenance, which account for the uncertainty in the site specific and generic data. These distributions were then combined with the specialized frequency distributions to obtain the component maintenance unavailability information to be applied in the system analyses. The methodology used in the development of the mean duration distributions is more fully described in the methodology section of the main report.

1.5.1.3.1.3 Comparison with Methodology Used in the Reactor Safety Study. The developmental methodology used in the RSS treatment of component maintenance data is similar in many respects to that used in this study, although the detail and depth of specialization in the RSS was limited because of the broad scope of the data base. Separate distributions for the frequency and duration of maintenance were developed based on discussions with plant maintenance personnel and using data from a review of the maintenance records of four plants during 1972. Because of the broad scope of the RSS study, this site specific data was not directly included in the data base, but served in the development of a lognormal distribution model for maintenance event duration and provided general information for typical repair time distributions for four classifications of components.

A single broad distribution for maintenance event frequency was assigned uniformly to all component types. Because of the various factors influencing maintenance frequency, three general prior distributions for frequency have been developed in this study. Each prior distribution is assigned to a specific component type based on the conditions under which the component is operated at each plant (including the specific technical specifications limitations applied). The assigned prior distribution is then specialized using the available site specific data to produce a unique description of the maintenance frequency directly applicable to the component being analyzed.

The RSS distributions for maintenance event duration were developed for four general component classifications: (1) pumps, (2) valves, (3) diesel generators, and (4) instrumentation. In recognition of the strong influence of the technical specifications on event duration, the pump classification was further subdivided into two specialized distributions, one applicable to pumps having a 24-hour technical specifications inoperability time limit and one for pumps with a 72-hour time limit. As discussed, the site specific evidence and increased experience with general plant maintenance practices have led to the general combination of pump and valve maintenance events into a single category of maintenance associated with a pump flow path. In this study, a total of four general prior distributions for maintenance event duration have been developed and specialized to the applicable components analyzed at each plant.

Because the current study is concerned with the analysis of specific components in a single plant, and because the level of detail available from the site specific data may be directly applied to this data base, the methodology for maintenance data development presented in this study, while generally similar to that discussed in the RSS, provides the level of specificity needed for a detailed analysis of each of the plant safety systems.

1.5.1.3.2 Component Maintenance Prior Distributions

The recirculation pumps have been excluded from the prior maintenance distributions presented in this section. These pumps are located inside the containment and are tested only during refueling outages with the unit at cold shutdown. Therefore, it would be extremely unlikely that any latent failures or degradation of these pumps would be detected during noncold shutdown periods. Furthermore, because of their location, the unit would have to be shut down for personnel radiation protection considerations before performing any maintenance on these pumps or their associated valves. Therefore, it is believed that no maintenance would be performed on these pumps during the periods of interest in this study.

1.5.1.3.2.1 Frequency of Maintenance. Prior distributions for the frequency of component maintenance were developed for three general component categories based on the component type, its normal service

duty, and the applied technical specifications inoperability limitations. These distributions are described in Tables 1.5.1-5 through 1.5.1-7.

1.5.1.3.2.2 Duration of Maintenance. Because the plant technical specifications have the most important influence on the duration of all but the most complex repair work, prior distributions for the duration of component maintenance were developed for four general component categories based primarily on their inoperability time limitations. These distributions are described in Tables 1.5.1-8A, 1.5.1-9A, 1.5.1-10A, and 1.5.1-11A.

Each of these distributions represents a single expression of the prior state of knowledge about the individual maintenance event durations. The mean value of each distribution is a single point estimate of the mean duration of maintenance for the given component type. To the extent that the given distribution represents the best estimate of the actual distribution of the duration data, the resulting mean value is the best estimate for the prior mean. To provide a framework for the expression of the uncertainty about this mean value (which must be included in the development of the component unavailability distributions), each of the distributions presented in Tables 1.5.1-8A, 1.5.1-9A, 1.5.1-10A, and 1.5.1-11A was expanded into a family of distributions by allowing the 5th and 95th percentiles of the lognormal curves to take on the ranges of values shown in Tables 1.5.1-8B, 1.5.1-9B, 1.5.1-10B, and 1.5.1-11B. The probability assigned to each of the values in the given range provides an expression of the uncertainty about the value of the parameter. The resulting distribution of mean values for maintenance event duration was then weighted in accordance with the relative probabilities assigned to the corresponding event duration distributions to express the "educated" prior states of knowledge about the distribution of the means presented in Tables 1.5.1-8B, 1.5.1-9B, 1.5.1-10B, and 1.5.1-11B.

1.5.1.3.2.3 Comparison with Distributions Used in the RSS. The maintenance frequency distribution applied to all components in the RSS study is characterized by the following lognormal parameters (RSS, page III-54):

5th Percentile:	1 month between events
95th Percentile:	12 months between events
Mean:	4.6 months between events

This distribution corresponds closely to the prior distribution presented in Table 1.5.1-7 for continuous service components and components with a high maintenance frequency. Because the RSS distribution was developed using the maintenance event summaries from four units during a single year of operation, this distribution may be unrealistically biased toward a relatively high maintenance frequency. This is especially true in the case of standby components having very

restrictive inoperability time limitations and reflects the expected lack of evidence of maintenance performed on these components in just 4 reactor years. While the distribution in the RSS may correctly model the frequency of maintenance as it applies to a broad collection of component types in several systems, this generally observed maintenance can be dominated by a relatively small subset of components with relatively high maintenance frequencies. Therefore, the distribution is not necessarily uniformly applicable to any given component in a specific system, regardless of the component's normal operating status or its imposed inoperability restrictions.

The RSS distributions for component maintenance event duration include two cases for pumps, one with a 24-hour inoperability time limit, and one with a 72-hour limit, and one case for diesel generators, with essentially a 72-hour inoperability limit. The parameters characterizing these lognormal distributions are (RSS, Table III 5-3):

- Pumps, 24-Hour Time Limit:

  5th Percentile: 0.5 hour/event

  95th Percentile: 24 hours/event

  Mean: 6.9 hours/event

- Pumps, 72-Hour Time Limit:

  5th Percentile: 0.5 hour/event

  95th Percentile: 72 hours/event

  Mean: 18.8 hours/event

- Diesel Generators:

  5th Percentile: 2 hours/event

  95th Percentile: 72 hours/event

  Mean: 21.7 hours/event

The distributions for the pump cases compare favorably with the corresponding prior distributions presented in Tables 1.5.1-8A and 1.5.1-9A, although the RSS distributions tend to include more optimism toward accomplishing maintenance in a short time than do the distributions in this study (possibly due to the inclusion of tag-out and return to service times in the component unavailability durations for this study). The differences between the distributions for the diesel generators are attributable primarily to the longer allowable inoperability period applied in this study as compared to that used in RSS.

The prior distributions for maintenance frequency and duration developed in this study compare favorably with the information presented in RSS if the differences in their levels of specificity are considered. The principal advantage of the more detailed distributions is that they provide specific information about the maintenance characteristics of a given component type at a given plant. Therefore, they give a more realistic representation of the actual variability of maintenance practices than is available through the broadly applicable distributions which were, of necessity, used in the RSS.

1.5.1.3.3 Site Specific Component Maintenance Data

The maintenance data presented in Tables 1.5.1-12A through 1.5.1-19 was obtained by an extensive review of all available maintenance work permits in effect during noncold shutdown periods at Indian Point Unit 2 between January 18, 1977 and June 13, 1980. The plant work permits were used because they provide a single source of information detailing: (1) the specific components affected by a given maintenance event; (2) the resulting effects on the system (e.g., the positions of valves, which circuit breakers were tagged out, etc.); (3) the entire duration of component unavailability, including the required tagout and return to service periods; and (4) the times and dates spanned by the maintenance period (for correlation with unit power operation records).

The information presented in these tables includes:

- Reporting Hours. The total number of noncold shutdown calendar hours in the given year for which maintenance data was available (may be less than the total number of noncold shutdown hours because of missing or otherwise unavailable records).

- Component Hours. The total number of noncold shutdown component service hours in the reporting period (obtained from the product of the reporting hours and the number of components available for the given type being analyzed).

- Maintenance Events. The number of individual maintenance events performed on the given component type during the reporting period.

- Total Maintenance Hours. The total duration of the maintenance events performed during the reporting period.

The data is presented on an annual basis to allow the identification of possible trends or unique cases which may not be representative of the normally observed maintenance practices at the plant.

No maintenance was performed on either the auxiliary component cooling pumps or the recirculation pumps during the noncold shutdown reporting period covered by this data base.

1.5.1.3.4 Specialized Component Maintenance Data

1.5.1.3.4.1 Component Maintenance Frequency. The site specific maintenance frequency data presented in Tables 1.5.1-12A through 1.5.1-20 was used to update the general frequency distributions described in Tables 1.5.1-5 through 1.5.1-7 to obtain the specialized lognormal distributions for component maintenance frequency shown in Table 1.5.1-21.

1.5.1.3.4.2 Mean Duration of Component Maintenance. The duration of each maintenance event used to determine the data base summarized in Tables 1.5.1-12A through 1.5.1-20 provided the site specific evidence to update the families of generalized event duration distributions developed from Tables 1.5.1-8A through 1.5.1-11B. The resulting specialized distributions of the mean duration of maintenance for each component type are presented in Figures 1.5.1-2 through 1.5.1-12.

1.5.1.3.4.3 Component Unavailability Due to Maintenance. To develop specialized information for the unavailability of components at Indian Point Unit 2 due to maintenance, the event frequency distributions presented in Table 1.5.1-21 and the distributions of event mean duration shown in Figures 1.5.1-2 through 1.5.1-12 were discretized and multiplied together using discrete probability distribution arithmetic. The resulting distributions of component unavailability are shown in Figures 1.5.1-13 through 1.5.1-23.

TABLE 1.5.1-5

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MAINTENANCE FREQUENCY - STANDBY PUMP, TESTED MONTHLY OR QUARTERLY

Distribution:	Lognormal
5th Percentile:	3.86×10^{-5} event/hour (1 event/36 months)
95th Percentile:	1.54×10^{-4} event/hour (1 event/9 months)
Mean:	8.42×10^{-5} event/hour (1 event/16.5 months)
Variance:	1.37×10^{-9}

Basis: Distribution range is indicative of very light duty components subjected to relatively frequent test starts which would detect component failures. A minimal preventive maintenance program is applied due to the standby nature of these components and the technical specifications inoperability criteria applied to maintenance performed during noncold shutdown periods.

Applicable to Indian Point Unit 2 Components:

- Containment Spray Pumps
- Safety Injection Pumps
- Auxiliary Component Cooling Pumps
- Residual Heat Removal Pumps*

*Although these pumps are operated continuously during all cold shutdown periods they are purely standby pumps during noncold shutdown periods, and maintenance performed during these periods would apply to failures detected during testing.

TABLE 1.5.1-6

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MAINTENANCE FREQUENCY - ALTERNATING SERVICE PUMP, TESTED MONTHLY OR QUARTERLY

Distribution:	Lognormal
5th Percentile:	5.79×10^{-5} event/hour (1 event/24 months)
95th Percentile:	2.31×10^{-4} event/hour (1 event/6 months)
Mean:	1.26×10^{-4} event/hour (1 event/11 months)
Variance:	3.09×10^{-9}

Basis: Distribution range is indicative of medium duty components subjected to periodic testing. Due to the generally less restrictive technical specifications inoperability criteria applied to these components, a nominal preventive maintenance frequency of approximately one event per 18 months of pump operation is included to account for routine inspections, lubrication programs, etc. performed during noncold shutdown periods.

Applicable to Indian Point Unit 2 Components:

- Auxiliary Feedwater Pumps

TABLE 1.5.1-7

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MAINTENANCE FREQUENCY - CONTINUOUS SERVICE COMPONENTS AND COMPONENTS SUBJECT TO HIGH FREQUENCY OF MAINTENANCE

Distribution:	Lognormal
5th Percentile:	7.72×10^{-5} event/hour (1 event/18 months)
95th Percentile:	4.63×10^{-4} event/hour (1 event/3 months)
Mean:	2.19×10^{-4} event/hour (1 event/6.3 months)
Variance:	1.66×10^{-8}

Basis: Distribution range is indicative of continuous service components or components requiring relatively frequent routine maintenance. Due to their relaxed technical specifications inoperability criteria, a nominal preventive maintenance frequency of approximately one event per 12 months of component service time is included to account for the necessary periodic inspections, routine repairs, and general overhauls typically performed on these components during noncold shutdown periods.

Applicable to Indian Point Unit 2 Components:

- Service Water Pumps
- Component Cooling Pumps
- Fan Cooler Units*
- Diesel Generators**

*Although the fan cooler units are located inside the containment and are relatively inaccessible during power operation, they are in continuous service, and maintenance is expected to be required on such items as circuit breakers, starting controls, service water supply and return valves, etc., all of which is accessible for routine maintenance and repair during noncold shutdown periods.
**The diesel generators are tested frequently, subject to minor failures and degradation requiring routine maintenance, and generally overhauled or tuned up according to a nominal preventive maintenance schedule.

TABLE 1.5.1-8A

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MAINTENANCE DURATION (24-HOUR TIME LIMIT)

Distribution:	Lognormal
5th Percentile:	2 hours/event
95th Percentile:	24 hours/event
Mean:	9.2 hours/event
Variance:	65

Basis: Only the most routine maintenance can be performed with a component unavailability time (including removal and return to service operations) of less than 2 hours. The 24-hour time limit for operation dictates that major scheduled maintenance will be performed only during periods of cold shutdown. Any major nonroutine maintenance or repairs requiring more than 24 hours to complete will necessitate unit shutdown. Since the data base excludes all maintenance performed during cold shutdown; if a maintenance event requires significantly longer than 24 hours to complete, the extended repair time is not included in the data base.

Applicable to Indian Point Unit 2 Components:

- Containment Spray Pumps
- Residual Heat Removal Pumps
- Safety Injection Pumps
- Auxiliary Component Cooling Pumps
- Fan Cooler Units*
- Component Cooling Pump 21**

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*The 24-hour time limit strictly applies to only fan cooler units 22, 24 and 25. Due to their power supplies, fan cooler units 21 and 23 have an applied 7-day inoperability time limit. However, since the actual maintenance performed on each of these units should be similar and since the specialized maintenance duration distribution will be applied to all five fan cooler units, the 24-hour limit has been applied to all of the fan coolers for this prior distribution.

**Due to the allocation of the component cooling pumps among the essential power supply buses, pump 22 or 23 may remain out of service indefinitely. Pump 21 may be inoperable for only 24 hours during power operation.

TABLE 1.5.1-8B

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MEAN DURATION OF MAINTENANCE (24-HOUR TIME LIMIT)

Parameters Characterizing Range of Lognormal Duration Distributions:

5th Percentile (hours/event)	Probability	95th Percentile (hours/event)	Probability
1.0	0.05	-	-
1.5	0.15	16	0.10
2.0	0.50	24	0.50
2.5	0.15	32	0.15
3.0	0.10	40	0.15
3.5	0.05	48	0.10

Resulting Prior Distribution of Mean Duration of Maintenance:

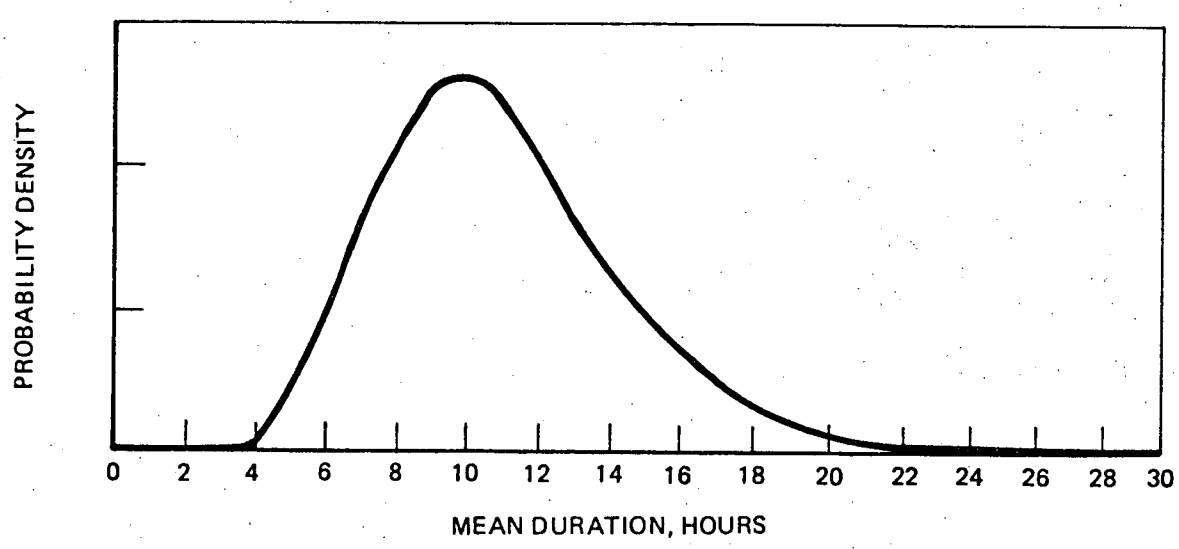

TABLE 1.5.1-9A

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MAINTENANCE DURATION (72-HOUR TIME LIMIT)

Distribution:	Lognormal
5th Percentile:	2 hours/event
95th Percentile:	60 hours/event
Mean:	18.7 hours/event
Variance:	668

Basis: Only the most routine maintenance can be performed with a component unavailability time (including removal and return to service operations) of less than 2 hours. The 72-hour time limit for operation dictates that major maintenance and repair activities will be performed during shutdown periods. Because of this limit, the maximum duration of any single event included in the data base is 92 hours, since the unit would be shut down and subsequently cooled to below 350°F per the technical specifications within this approximate time limit. The majority of relatively routine maintenance and some extensive repairs will be completed within 2-1/2 days, given the high priority assigned to returning the equipment to service within 72 hours.

Applicable to Indian Point Unit 2 Components:

- Auxiliary Feedwater Pumps

TABLE 1.5.1-9B

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MEAN DURATION OF MAINTENANCE (72-HOUR TIME LIMIT)

Parameters Characterizing Range of Lognormal Duration Distributions:

5th Percentile (hours/event)	Probability	95th Percentile (hours/event)	Probability
1.0	0.05	-	-
2.0	0.50	24	0.05
3.0	0.15	36	0.05
4.0	0.10	48	0.15
5.0	0.05	60	0.50
6.0	0.05	72	0.15
7.0	0.05	84	0.05
8.0	0.05	96	0.05

Resulting Prior Distribution of Mean Duration of Maintenance.

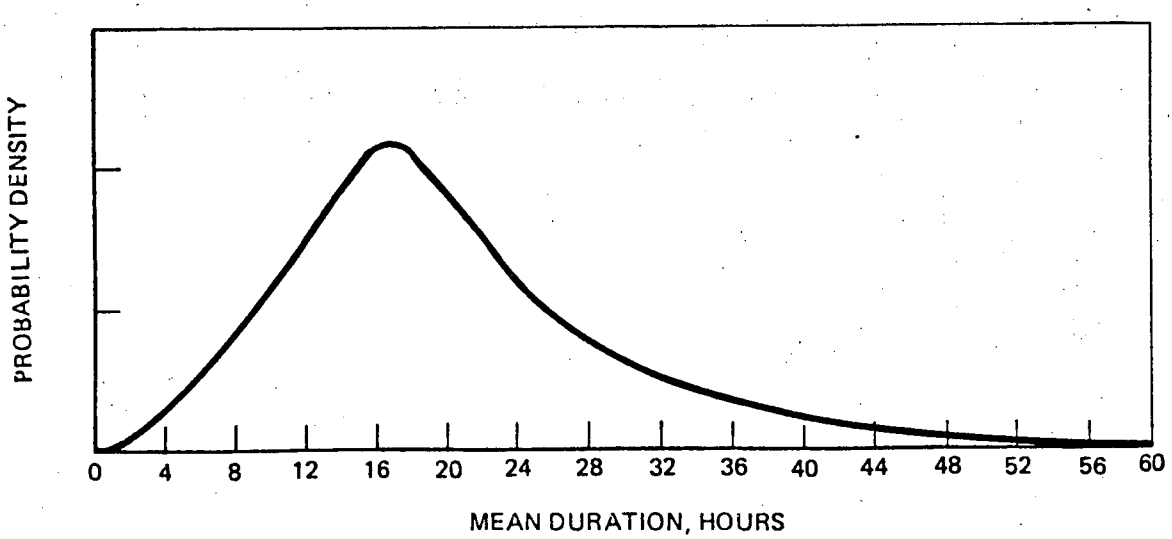

TABLE 1.5.1-10A

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MAINTENANCE DURATION
(7-DAY TIME LIMIT)

Distribution:	Lognormal
5th Percentile:	2 hours/event
95th Percentile:	120 hours/event
Mean:	33.6 hours/event
Variance:	4.18×10^3

Basis: Only the most routine maintenance can be performed with a component unavailability time (including removal and return to service operations) of less than 2 hours. The 7-day time limit for unit operation dictates that most maintenance will be prioritized to be completed within approximately 5 days to allow for possible unforeseen delays. Furthermore, since most scheduled major maintenance and equipment overhaul is performed during the Monday through Friday work week, the 5-day time limit applies to most of these planned activities as well.

Applicable to Indian Point Unit 2 Components:

- Diesel Generators

TABLE 1.5.1-10B

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MEAN DURATION OF MAINTENANCE (7-DAY TIME LIMIT)

Parameters Characterizing Range of Lognormal Duration Distributions:

5th Percentile (hours/event)	Probability	95th Percentile (hours/event)	Probability
1	0.05	48	0.05
2	0.50	72	0.10
4	0.15	96	0.10
8	0.10	120	0.50
12	0.10	144	0.15
16	0.05	168	0.05
24	0.05	240	0.05

Resulting Prior Distribution of Mean Duration of Maintenance:

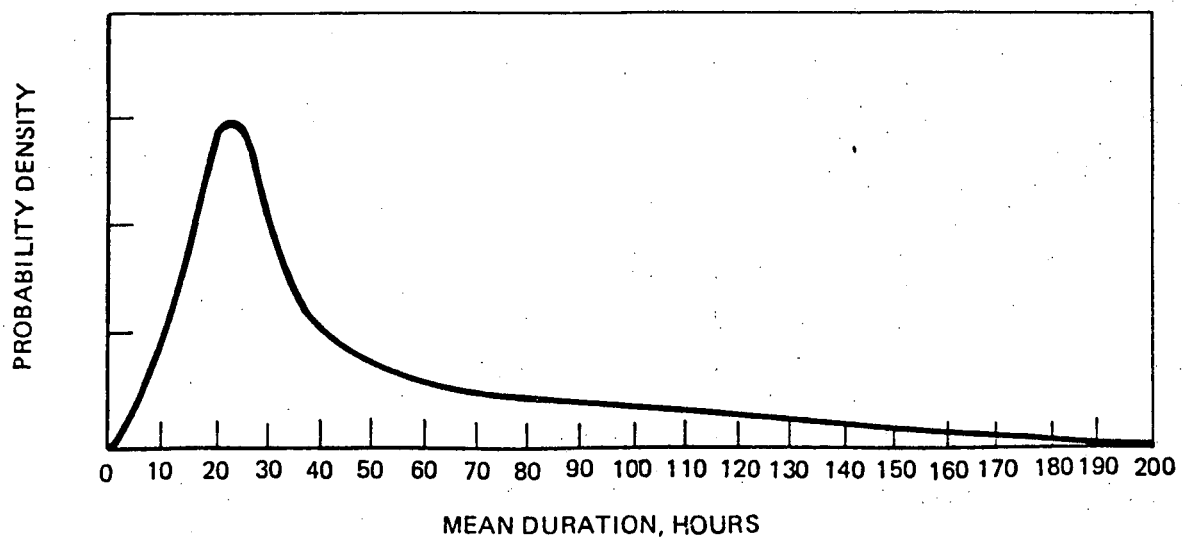

TABLE 1.5.1-11A

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MAINTENANCE DURATION
(NO TIME LIMIT)

Distribution:	Lognormal
5th Percentile:	4 hours/event
95th Percentile:	336 hours/event
Mean:	91 hours/event
Variance:	4.23×10^4

Basis: Given the relatively low priority generally assigned to maintenance of these components (with respect to more restrictive components), the approximate minimum time required for performance of most maintenance, including removal and return to service operations, is 4 hours. The majority of maintenance events, including major repairs or component replacement, should be accomplished within 2 weeks, given only moderate priority. A number of events could, of course, take considerably longer to complete, but these events are the exceptions and should not account for more than 5% of all maintenance activities.

Applicable to Indian Point Unit 2 Components:

- Service Water Pumps*
- Component Cooling Pumps 22 and 23**

*When one service water pump becomes inoperable, the nuclear system loads must be transferred to the redundant pump header within 8 hours. After this transfer, the inoperable pump may remain out of service indefinitely and is unavailable for operation on the nuclear system header.

**Due to the allocation of the component cooling pumps among the essential power supply buses, pump 22 or 23 may remain out of service indefinitely. Pump 21 may be inoperable for only 24 hours during power operation.

TABLE 1.5.1-11B

INDIAN POINT 2 PRIOR DISTRIBUTION FOR MEAN DURATION OF MAINTENANCE (NO TIME LIMIT)

Parameters Characterizing Range of Lognormal Duration Distributions:

5th Percentile (hours/event)	Probability	95th Percentile (hours/event)	Probability
2	0.05	24	0.05
4	0.50	48	0.10
8	0.20	120	0.20
16	0.10	336	0.50
24	0.10	720	0.10
48	0.05	2,000	0.05

Resulting Prior Distribution of Mean Duration of Maintenance:

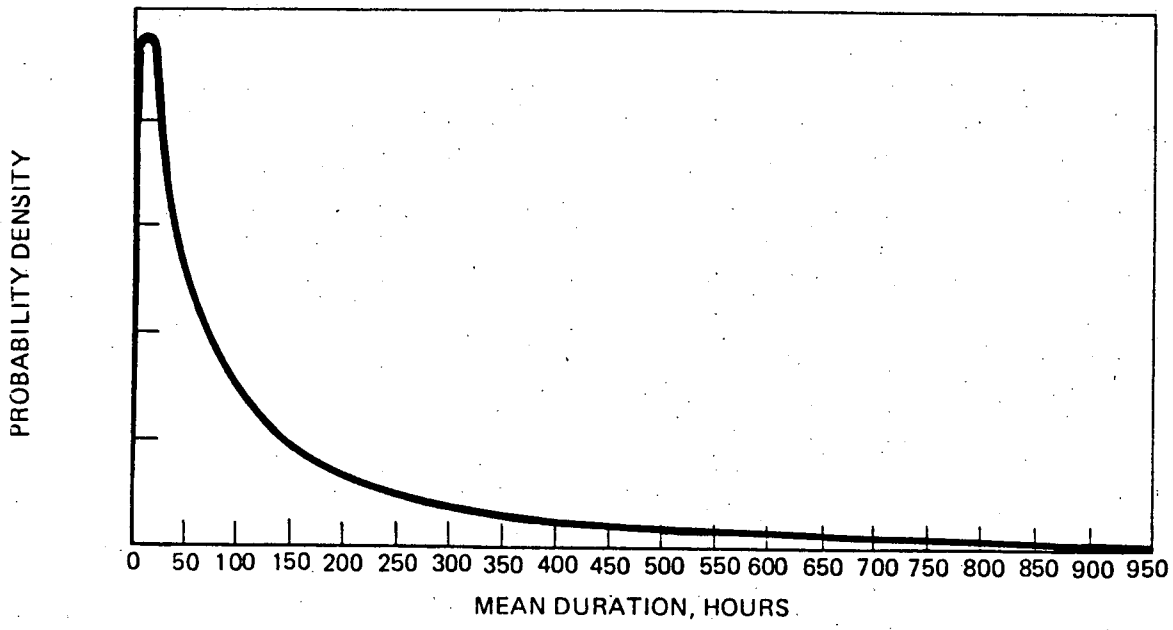

TABLE 1.5.1-12A

INDIAN POINT 2 COMPONENT TYPE: TURBINE-DRIVEN AUXILIARY FEEDWATER PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	5,520	2	33
1978	3,912	3,912	1	4
1979	5,832	5,832	2	113*
1980	2,568	2,568	1	92*

*The current technical specifications for Indian Point 2 allow one auxiliary feedwater pump to be inoperable for 72 hours during power operation. If the pump is not returned to service within 72 hours, the unit must be shut down within an additional 12 hours and subsequently cooled to <350°F. The maximum total elapsed time from the initiation of maintenance is thus approximately 92 hours (allowing 8 hours for cooldown to <350°F). Prior to the 1980 implementation of the current technical specifications revision, a single auxiliary feedwater pump could have been inoperable indefinitely, and a 72-hour time limit was applied to any additional inoperable pump. Since all of the maintenance events summarized above apply to only single pumps, the historical data has been modified to account for the current maximum allowable inoperability period by truncating all maintenance events extending beyond 92 hours to this time limit. This truncation was applied to one event in 1979 with a duration of 168 hours and one event in 1980 with a duration of 173 hours to obtain the given times.

TABLE 1.5.1-12B

INDIAN POINT 2 COMPONENT TYPE: MOTOR-DRIVEN AUXILIARY FEEDWATER PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	11,040	1	86
1978	3,912	7,824	0	0
1979	5,832	11,664	0	0
1980	2,568	5,136	1	6

TABLE 1.5.1-13

INDIAN POINT 2 COMPONENT TYPE: COMPONENT COOLING PUMP 21

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	5,520	0	0
1978	3,912	3,912	0	0
1979	5,832	5,832	1	1
1980	2,568	2,568	0	0

TABLE 1.5.1-14

INDIAN POINT 2 COMPONENT TYPE: COMPONENT COOLING PUMPS 22 AND 23

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	11,040	1	872
1978	3,912	7,824	1	339
1979	5,832	11,664	1	8
1980	2,568	5,136	0	0

TABLE 1.5.1-15

INDIAN POINT 2 COMPONENT TYPE: CONTAINMENT SPRAY PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	11,040	1	2
1978	3,912	7,824	0	0
1979	5,832	11,664	2	13
1980	2,568	5,136	0	0

TABLE 1.5.1-16

INDIAN POINT 2 COMPONENT TYPE: RESIDUAL HEAT REMOVAL PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	11,040	1	16
1978	3,912	7,824	2	20
1979	5,832	11,664	0	0
1980	2,568	5,136	0	0

TABLE 1.5.1-17

INDIAN POINT 2 COMPONENT TYPE: SAFETY INJECTION PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	16,560	0	0
1978	3,912	11,736	5	99*
1979	5,832	17,496	1	2
1980	2,568	7,704	0	0

*Includes one event of a 78.5-hour duration

TABLE 1.5.1-18

INDIAN POINT 2 COMPONENT TYPE: SERVICE WATER PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	33,120	5	2,283[a]
1978	3,912	23,472	11	2,732[b]
1979	5,832	34,992	14	2,012[c]
1980	2,568	15,408	7	2,384[d]

[a] Includes one event of a 2,256-hour duration
[b] Includes one event of a 2,010-hour duration
[c] Includes one event of a 1,064-hour duration
[d] Includes one event of a 1,296-hour duration and one event of a 980-hour duration

TABLE 1.5.1-19

INDIAN POINT 2 COMPONENT TYPE: FAN COOLER UNITS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	27,600	0	0
1978	3,912	19,560	1	48
1979	5,832	29,160	2	42
1980	2,568	12,840	2	64

TABLE 1.5.1-20

INDIAN POINT 2 COMPONENT TYPE: DIESEL GENERATORS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1977	5,520	16,560	15	471
1978	3,912	11,736	9	164
1979	5,832	17,496	22	714
1980	2,568	7,704	7	184

TABLE 1.5.1-21

INDIAN POINT 2 SPECIALIZED COMPONENT MAINTENANCE FREQUENCY DATA

Component	Site Specific Data		Prior Distribution Table	Specialized Frequency Distribution*	
	Events	Service Hours		Mean (Events/Hours)	Variance
Turbine-Driven Auxiliary Pumps	6	1.78×10^{4}	1.5.1-6	1.91×10^{-4}	4.13×10^{-9}
Motor-Driven Auxiliary Pumps	2	3.57×10^{4}	1.5.1-6	8.57×10^{-5}	1.02×10^{-9}
Component Cooling Pump 21	1	1.78×10^{4}	1.5.1-7	1.29×10^{-4}	2.19×10^{-9}
Component Cooling Pumps 22 and 23	3	3.57×10^{4}	1.5.1-7	1.37×10^{-4}	3.32×10^{-9}
Containment Spray Pumps	3	3.57×10^{4}	1.5.1-5	8.26×10^{-5}	7.87×10^{-10}
Residual Heat Removal Pumps	3	3.57×10^{4}	1.5.1-5	8.26×10^{-5}	7.87×10^{-10}
Safety Injection Pumps	6	5.35×10^{4}	1.5.1-5	9.56×10^{-5}	8.60×10^{-10}
Service Water Pumps	37	1.07×10^{5}	1.5.1-7	3.26×10^{-4}	2.36×10^{-9}
Fan Cooler Units	5	8.92×10^{4}	1.5.1-7	8.74×10^{-5}	6.74×10^{-10}
Diesel Generators	53	5.35×10^{4}	1.5.1-7	9.05×10^{-4}	1.85×10^{-8}
Auxiliary Component Cooling Pumps	0	3.57×10^{4}	1.5.1-5	5.77×10^{-5}	4.42×10^{-10}

*Distributions are lognormal

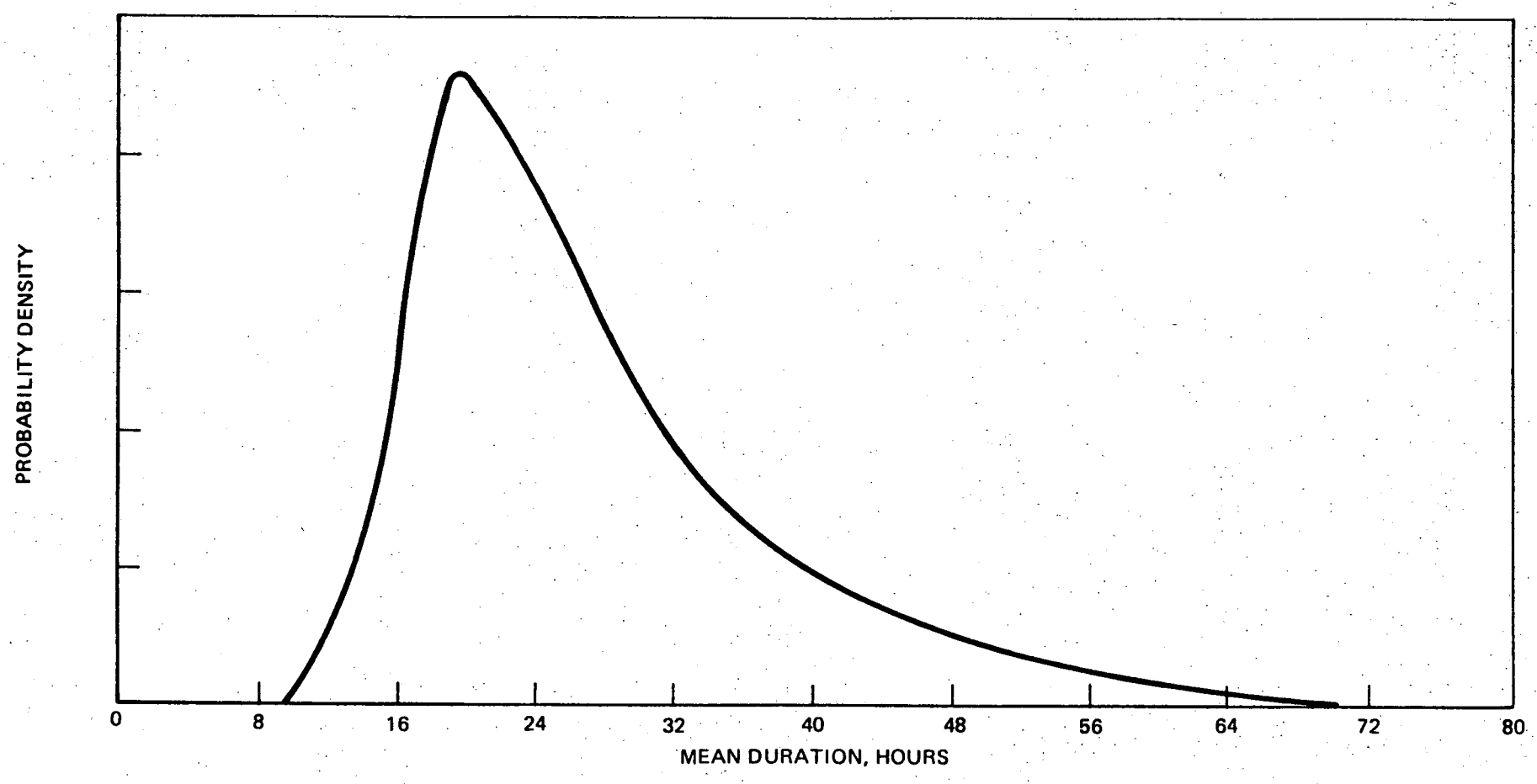

Figure 1.5.1-2. Indian Point 2 Turbine-Driven Auxiliary Feedwater Pump Specialized Mean Duration of Maintenance

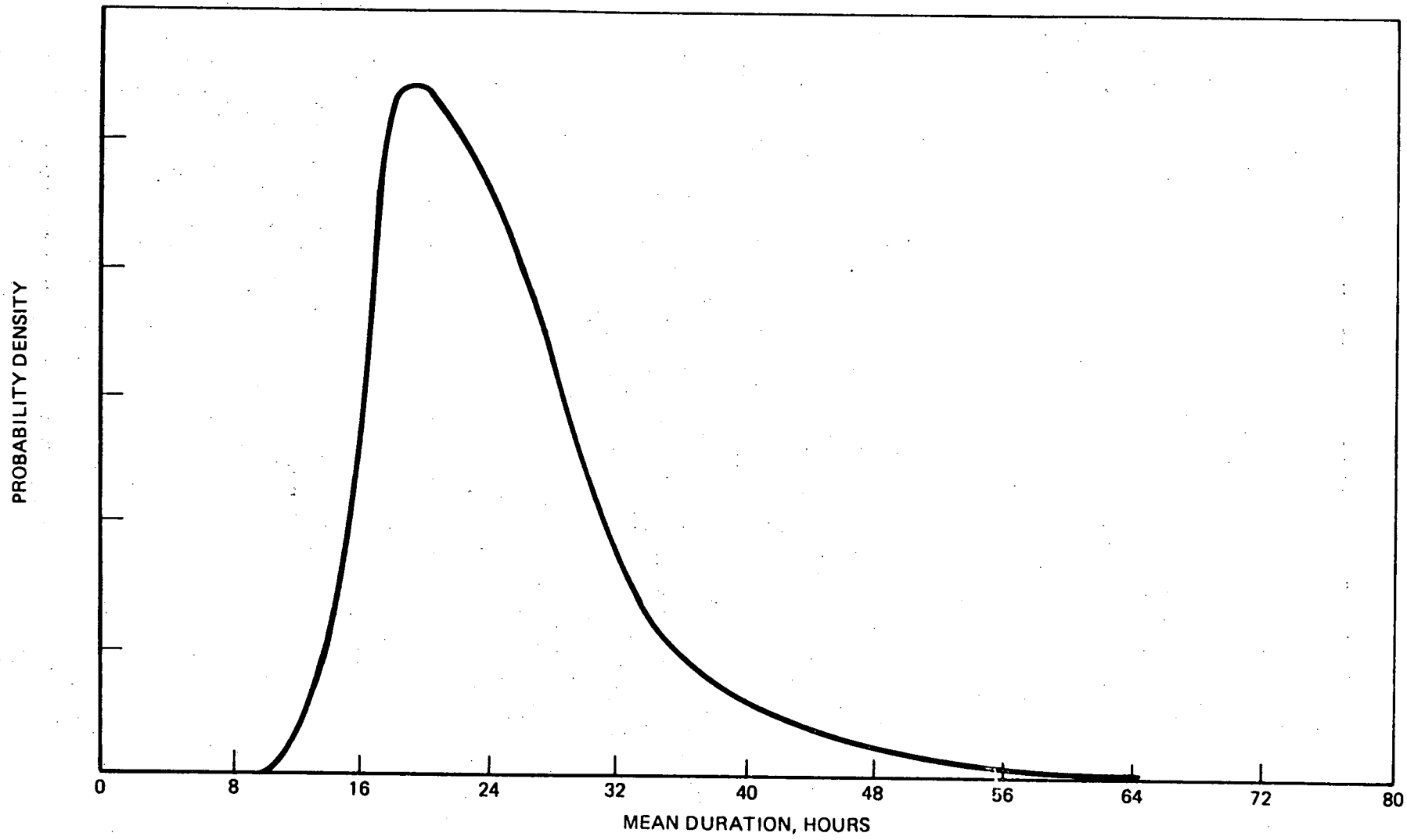

Figure 1.5.1-3. Indian Point 2 Motor-Driven Auxiliary Feedwater Pumps Specialized Mean Duration of Maintenance

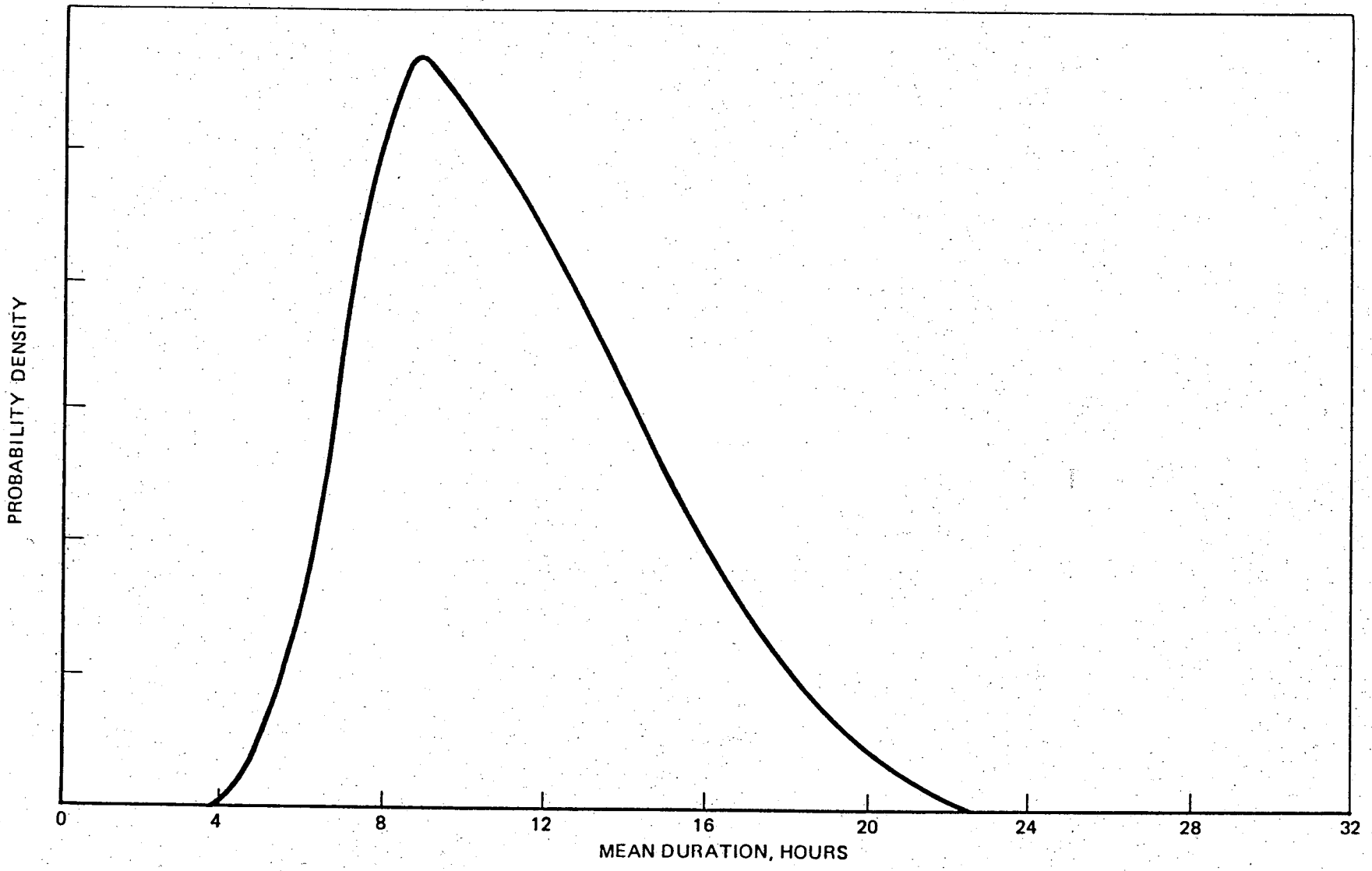

Figure 1.5.1-4. Indian Point 2 Component Cooling Pump 21
Specialized Mean Duration of Maintenance

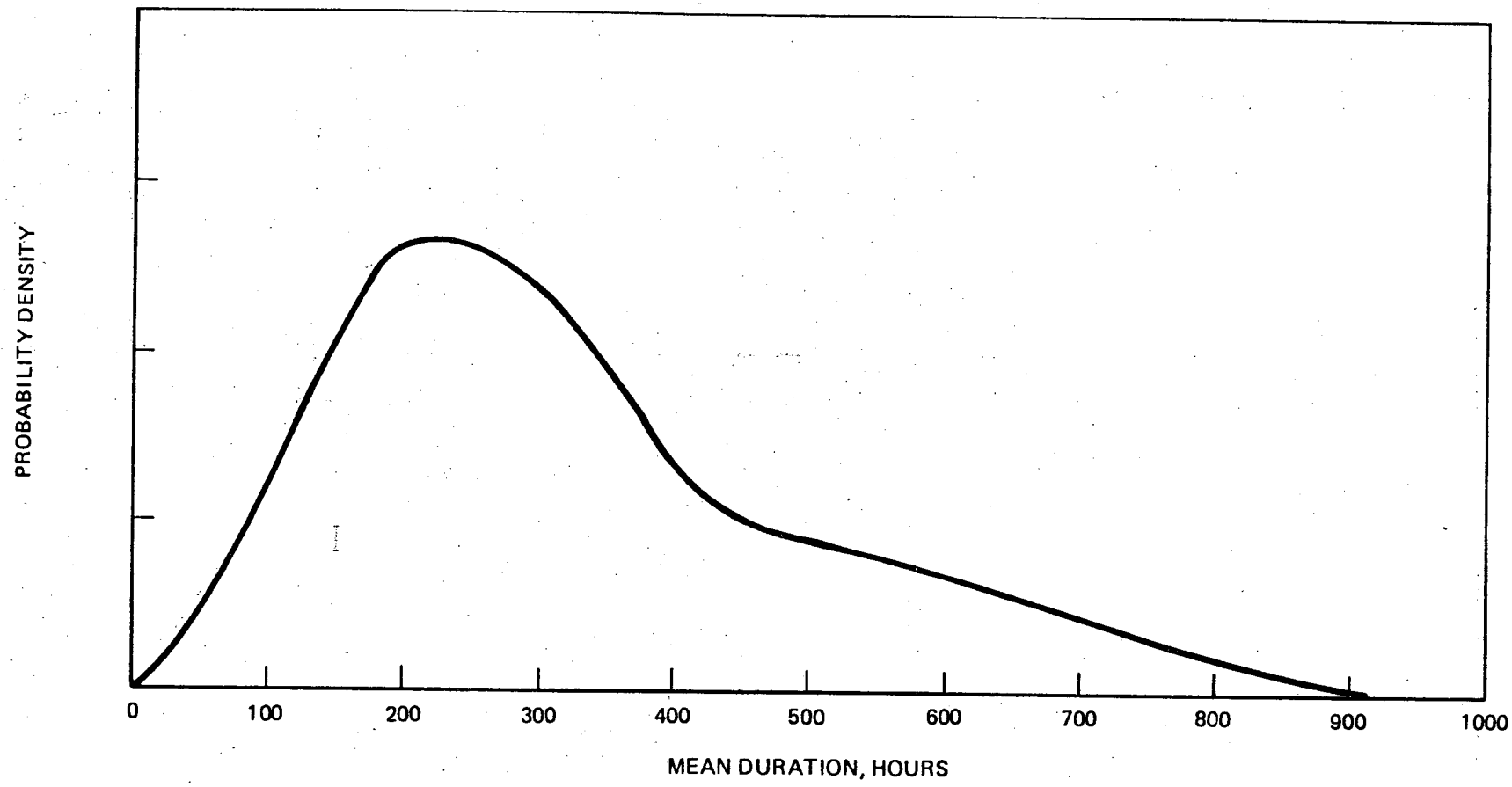

Figure 1.5.1-5. Indian Point 2 Component Cooling Pumps 22 and 23
Specialized Mean Duration of Maintenance

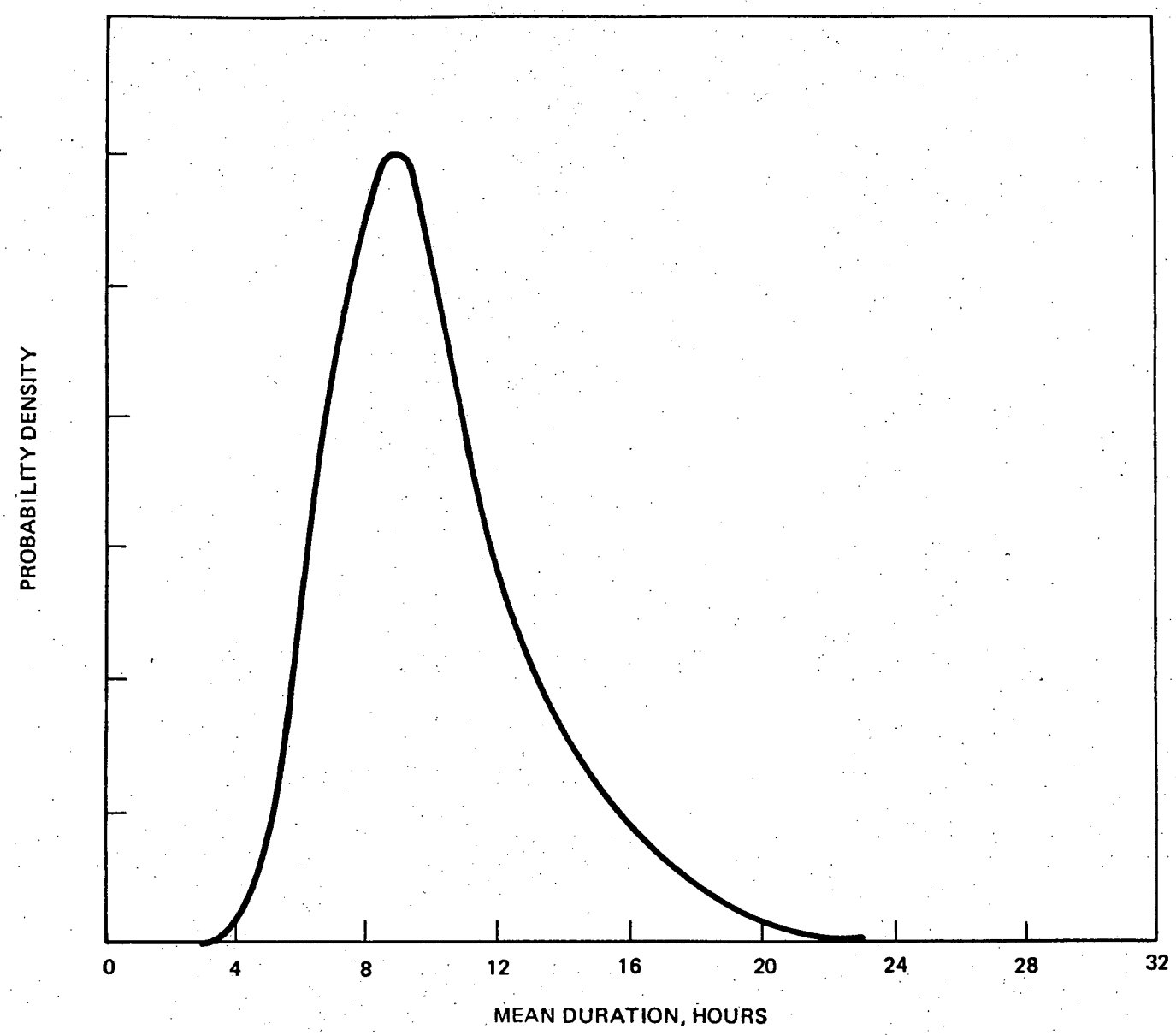

Figure 1.5.1-6. Indian Point 2 Containment Spray Pumps
Specialized Mean Duration of Maintenance

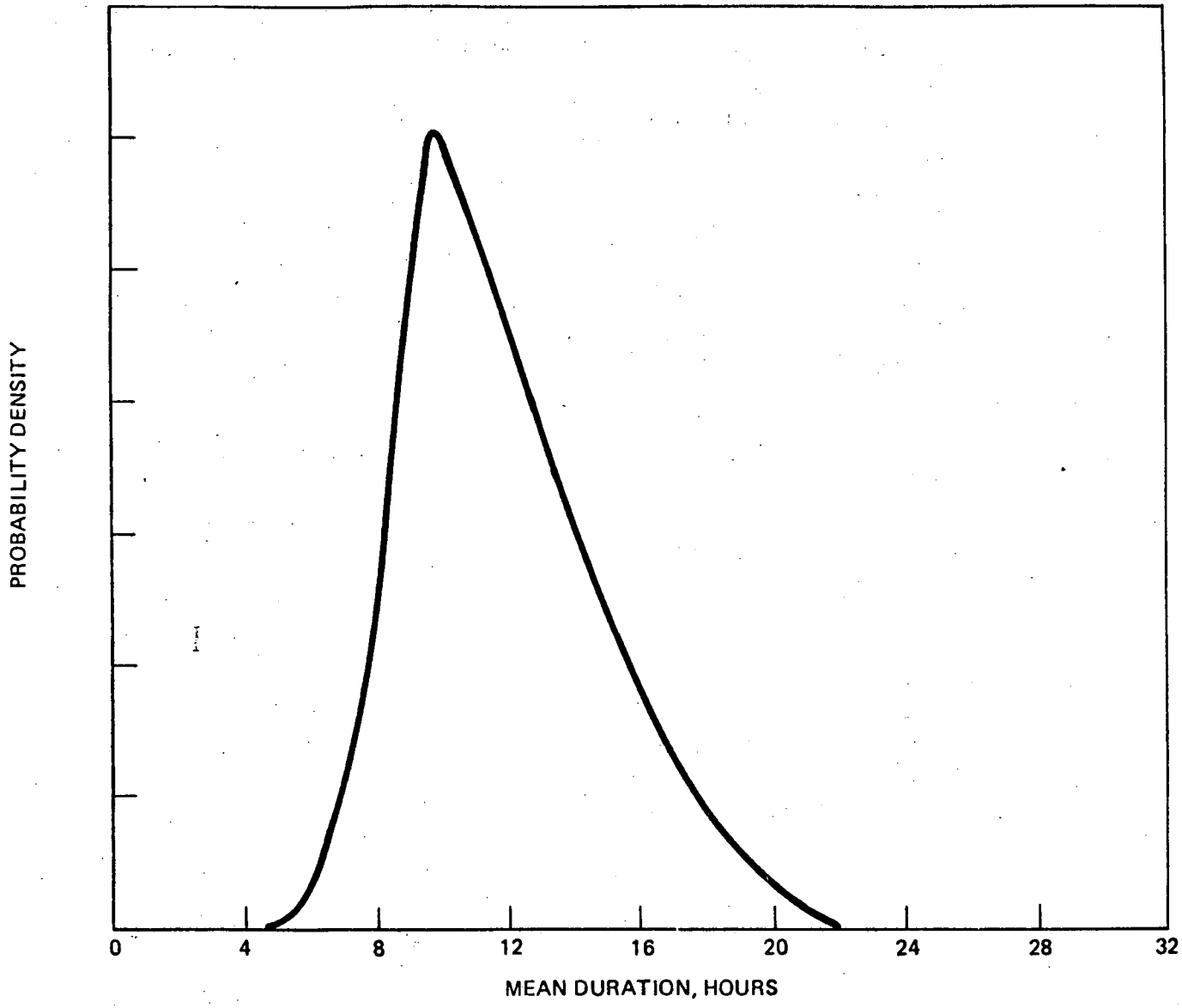

Figure 1.5.1-7. Indian Point 2 Residual Heat Removal Pumps
Specialized Mean Duration of Maintenance

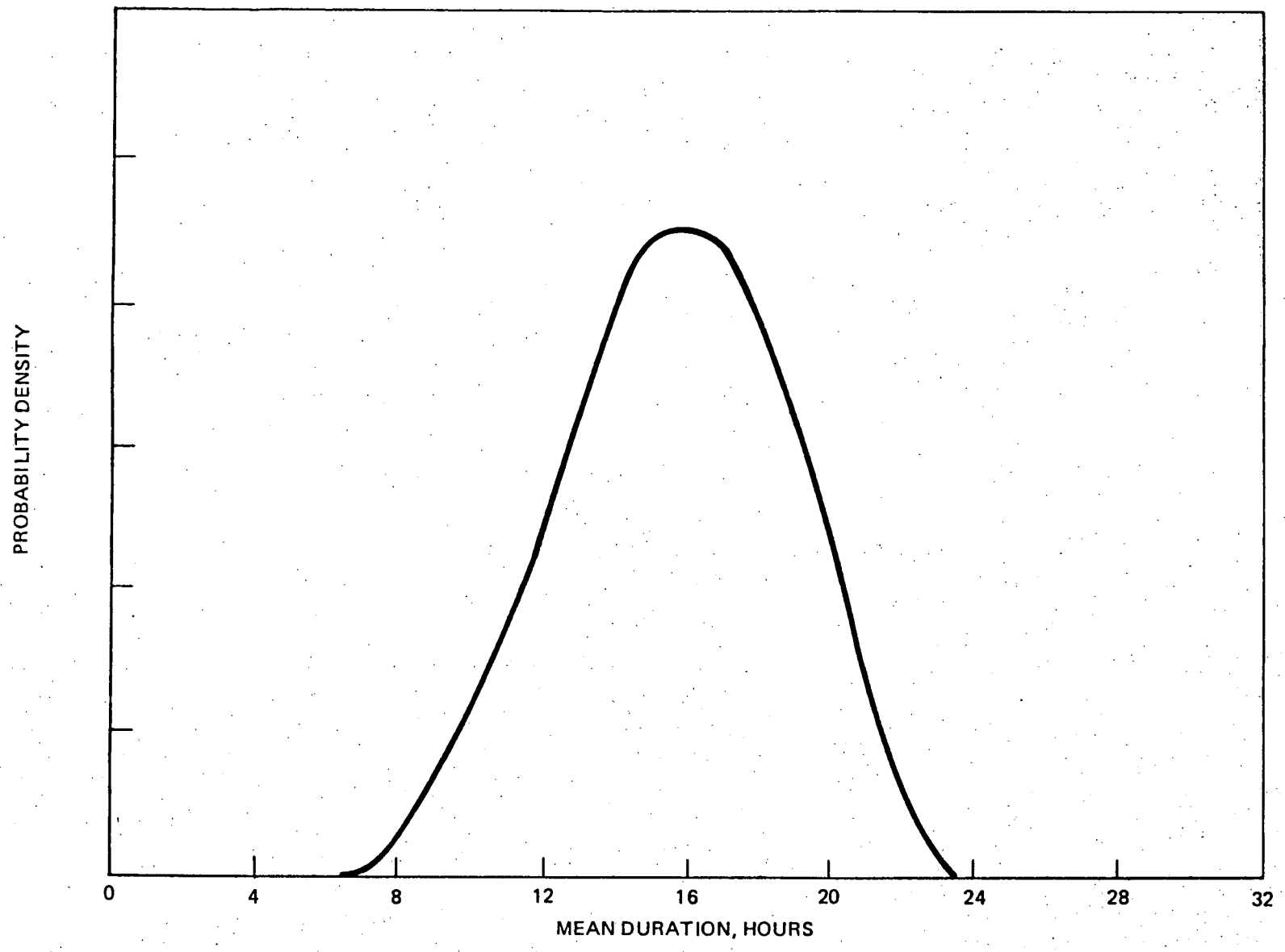

Figure 1.5.1-8. Indian Point 2 Safety Injection Pumps
Specialized Mean Duration of Maintenance

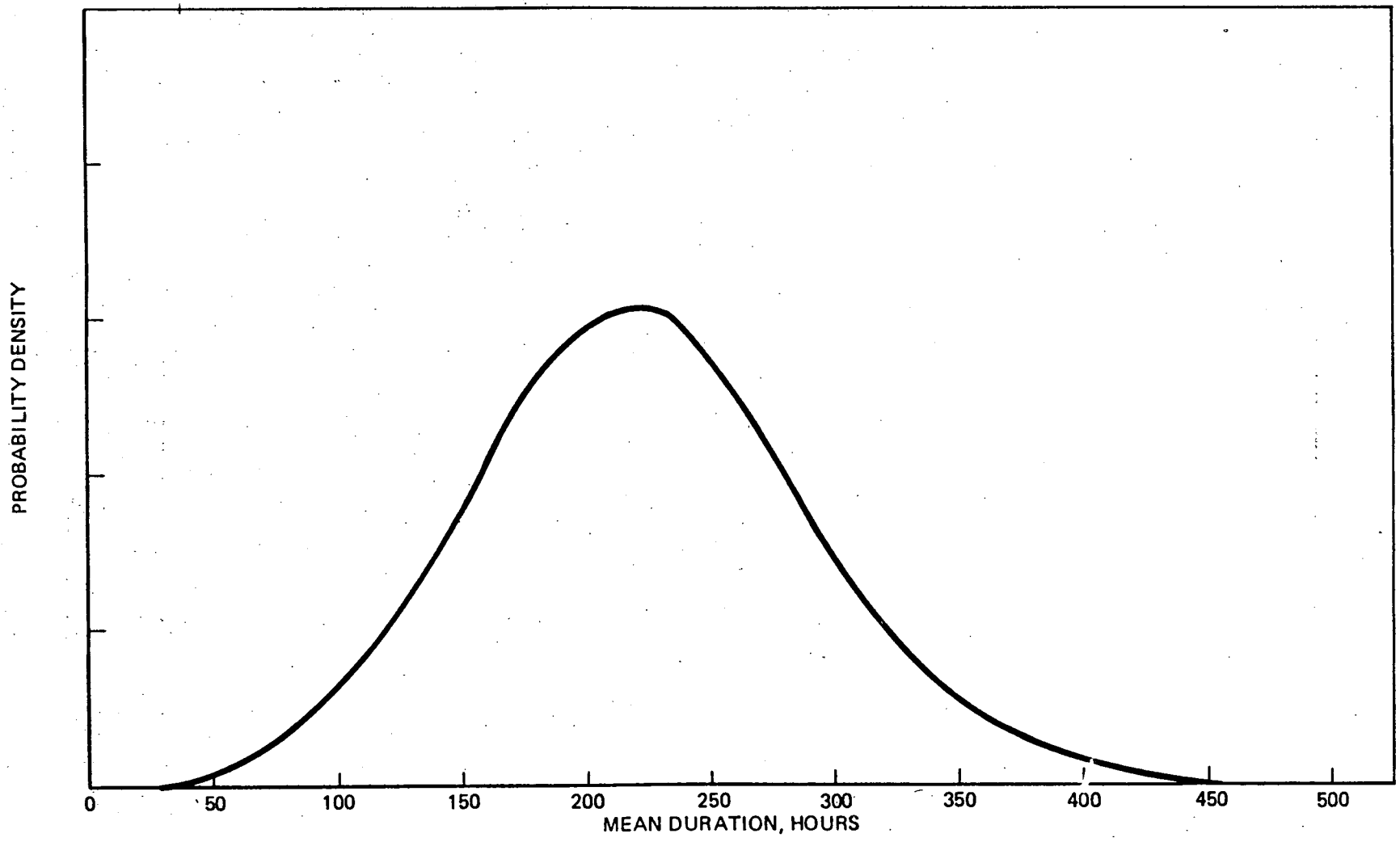

Figure 1.5.1-9. Indian Point 2 Service Water Pumps
Specialized Mean Duration of Maintenance

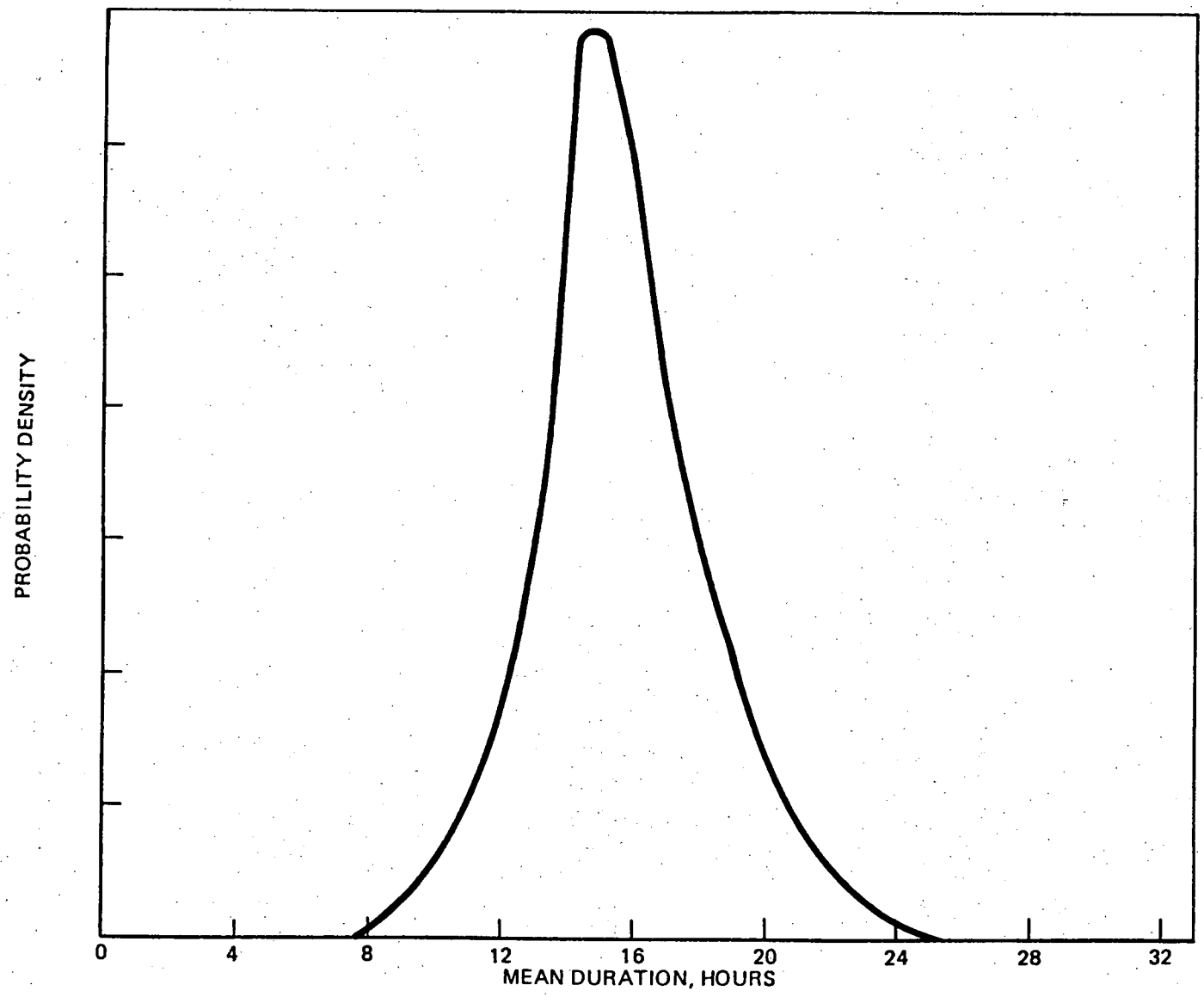

Figure 1.5.1-10. Indian Point 2 Fan Cooler Units
Specialized Mean Duration of Maintenance

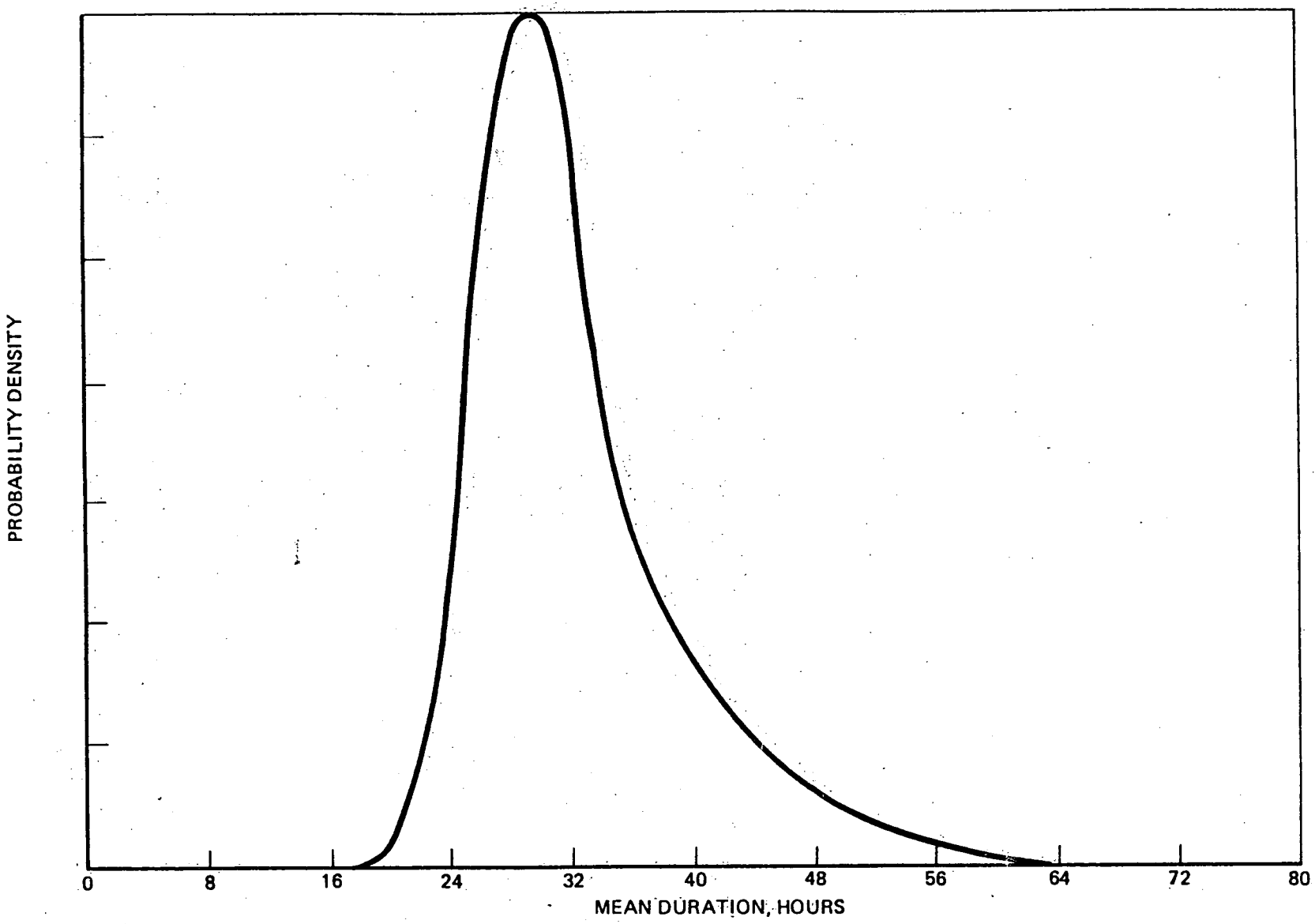

Figure 1.5.1-11. Indian Point 2 Diesel Generators
Specialized Mean Duration of Maintenance

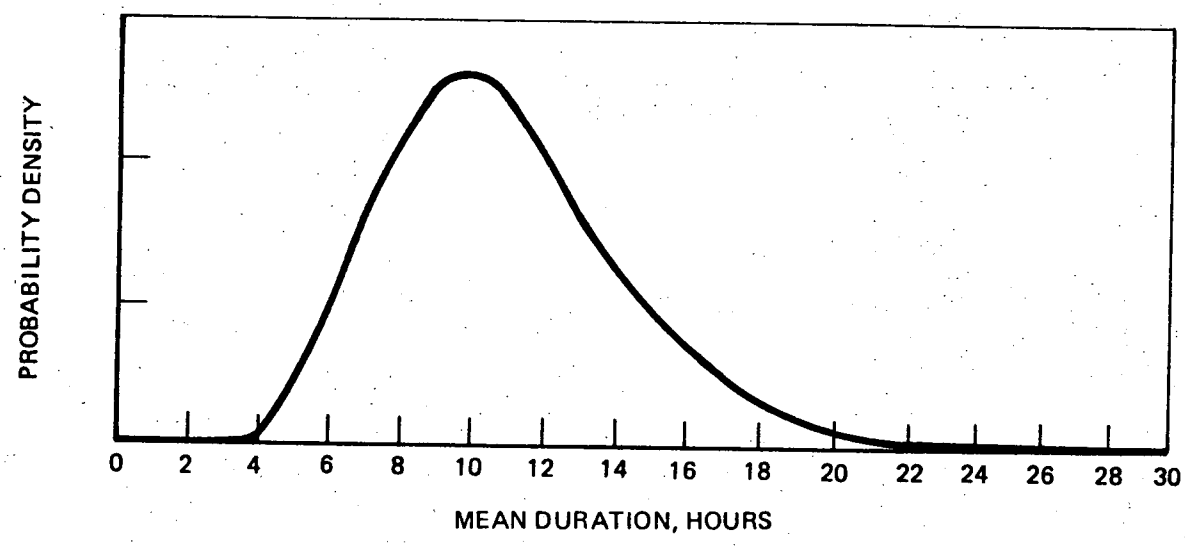

Figure 1.5.1-12. Indian Point 2 Auxiliary Component Cooling Pumps Specialized Mean Duration of Maintenance

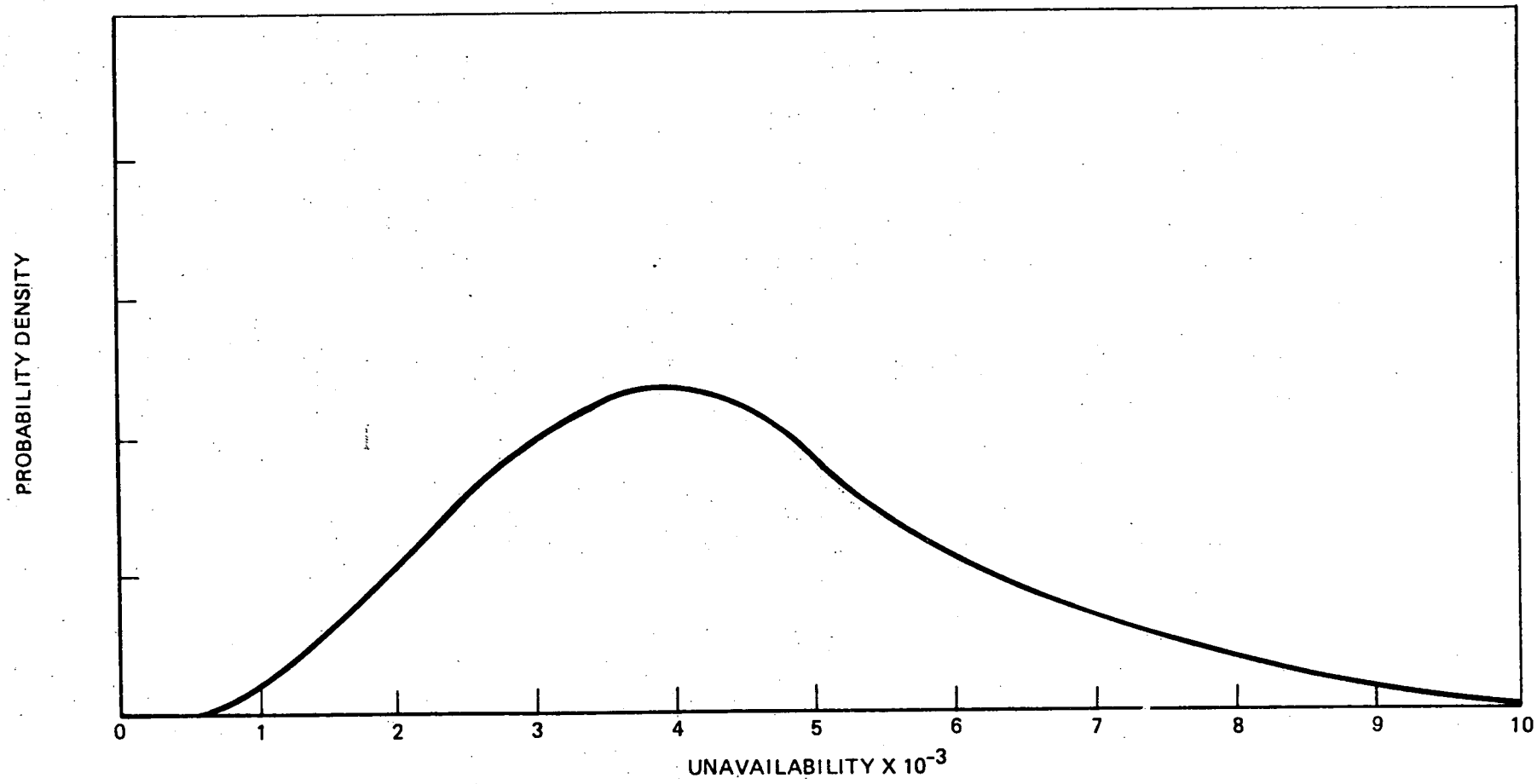

Figure 1.5.1-13. Indian Point 2 Turbine-Driven Auxiliary Feedwater Pump Unavailability Due to Maintenance

(Mean = 4.56×10^{-3})

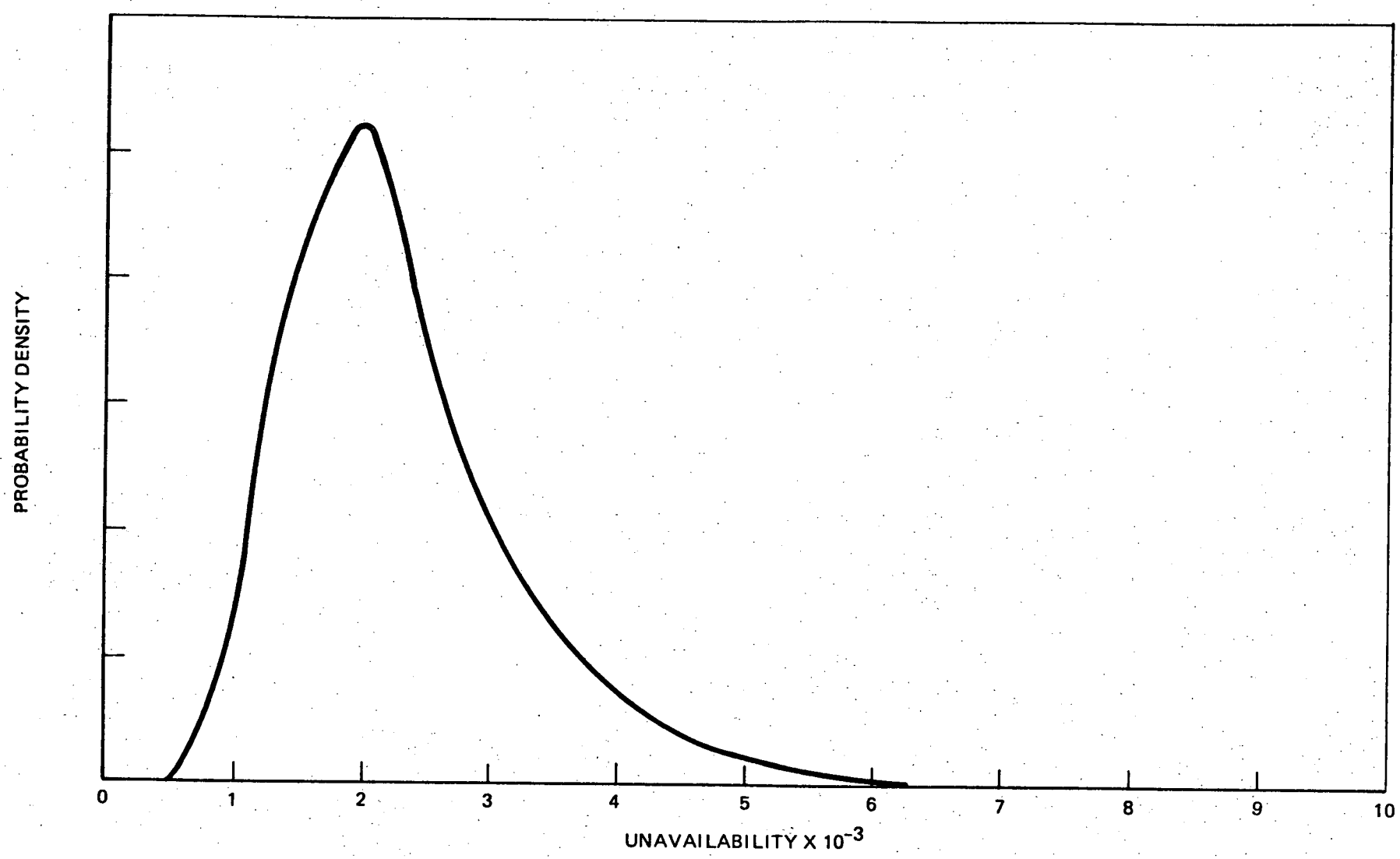

Figure 1.5.1-14. Indian Point 2 Motor-Driven Auxiliary Feedwater Pumps Unavailability Due to Maintenance

(Mean = 2.26×10^{-3})

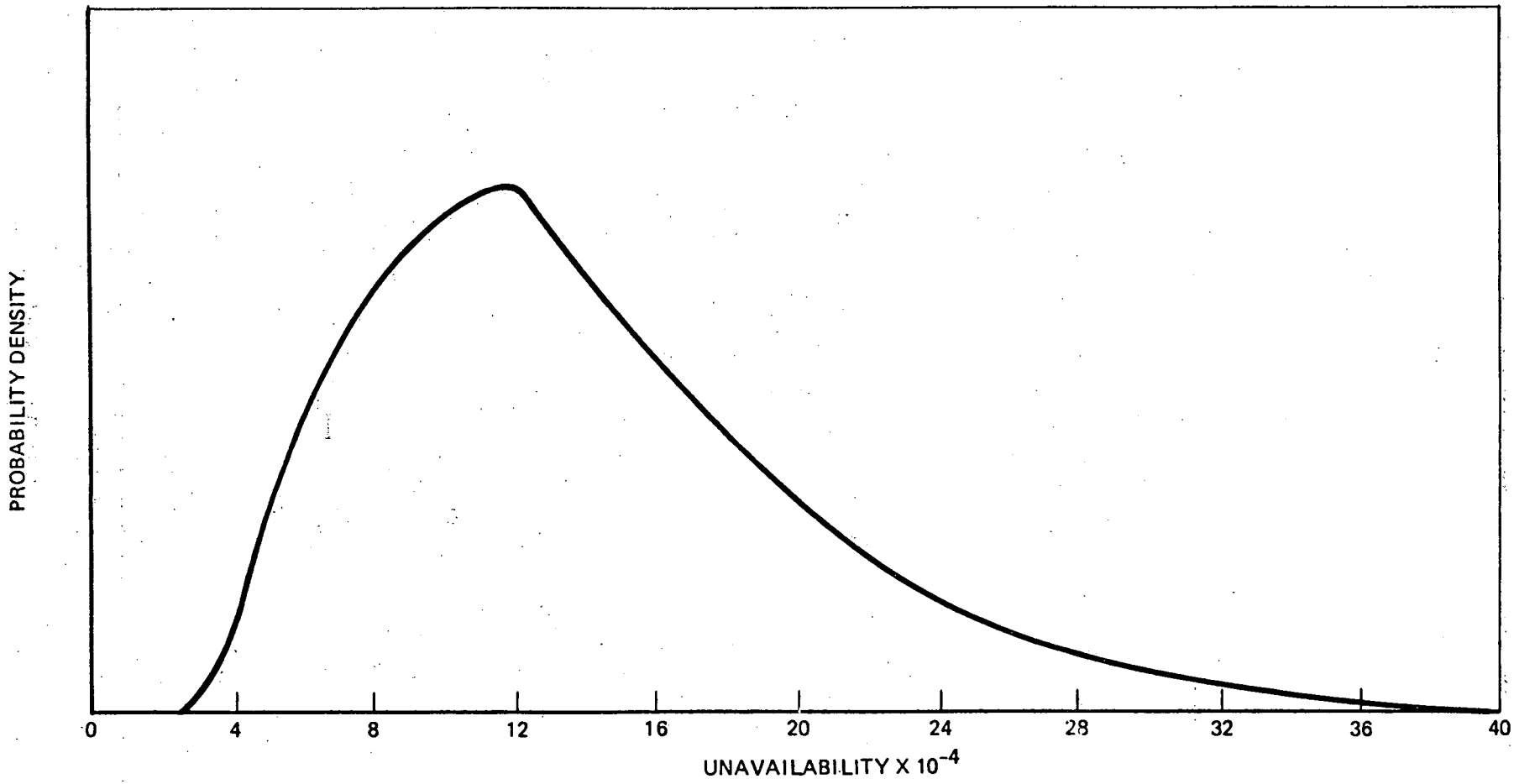

Figure 1.5.1-15. Indian Point 2 Component Cooling Pump 21
Unavailability Due to Maintenance
(Mean = 1.39×10^{-3})

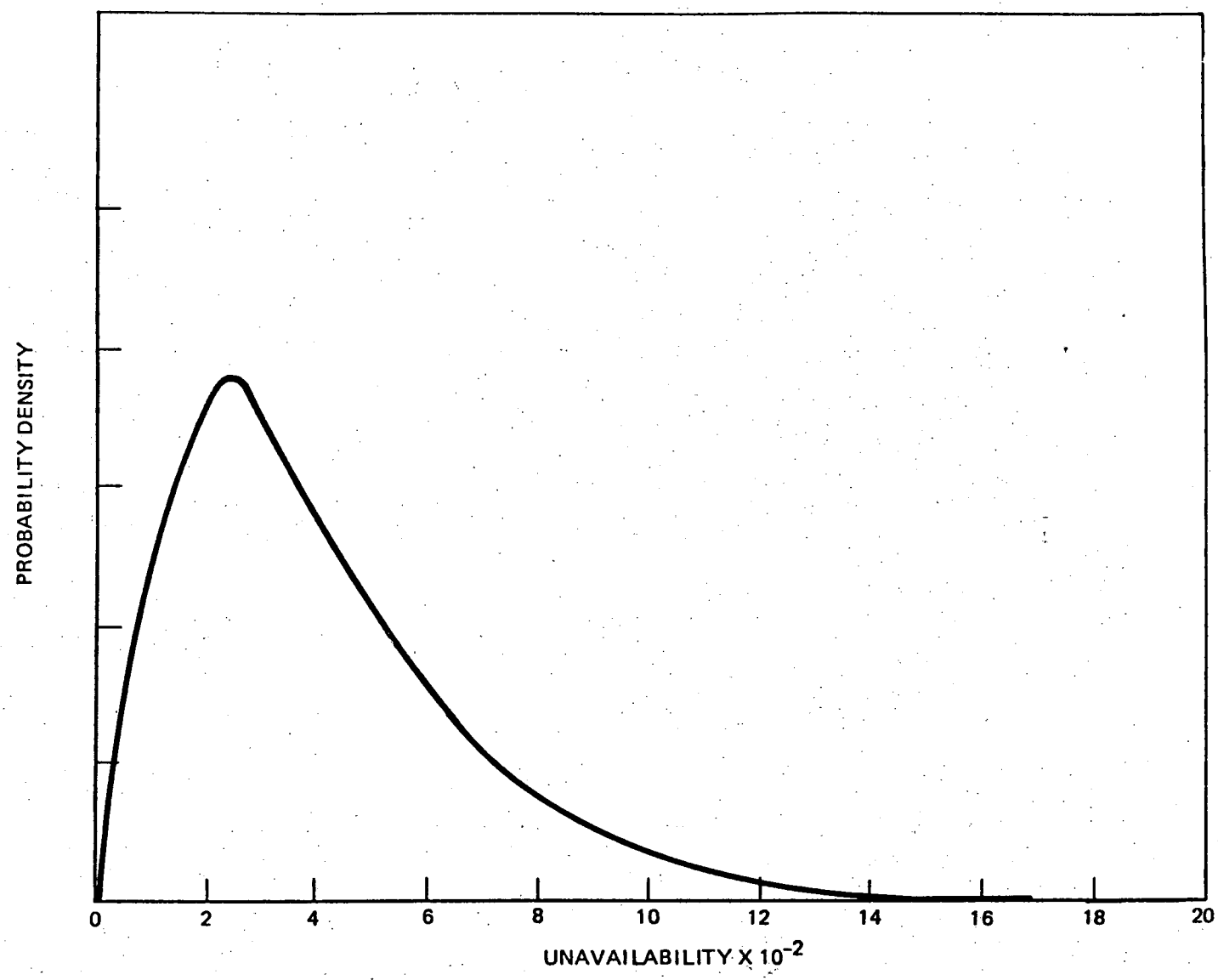

Figure 1.5.1-16. Indian Point 2 Component Cooling Pumps 22 and 23 Unavailability Due to Maintenance

(Mean = 4.19×10^{-2})

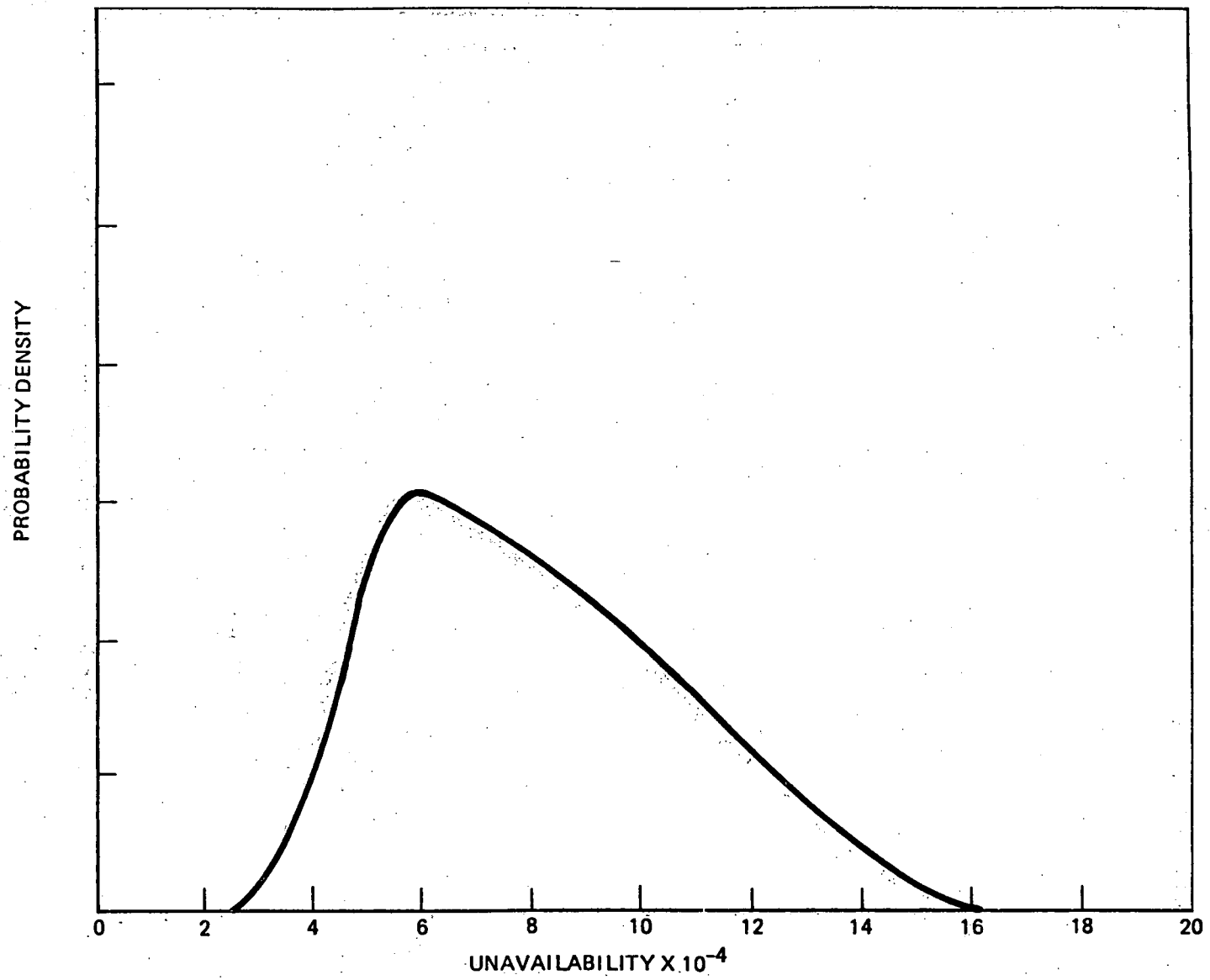

Figure 1.5.1-17. Indian Point 2 Containment Spray Pumps Unavailability Due to Maintenance

(Mean = 8.08×10^{-4})

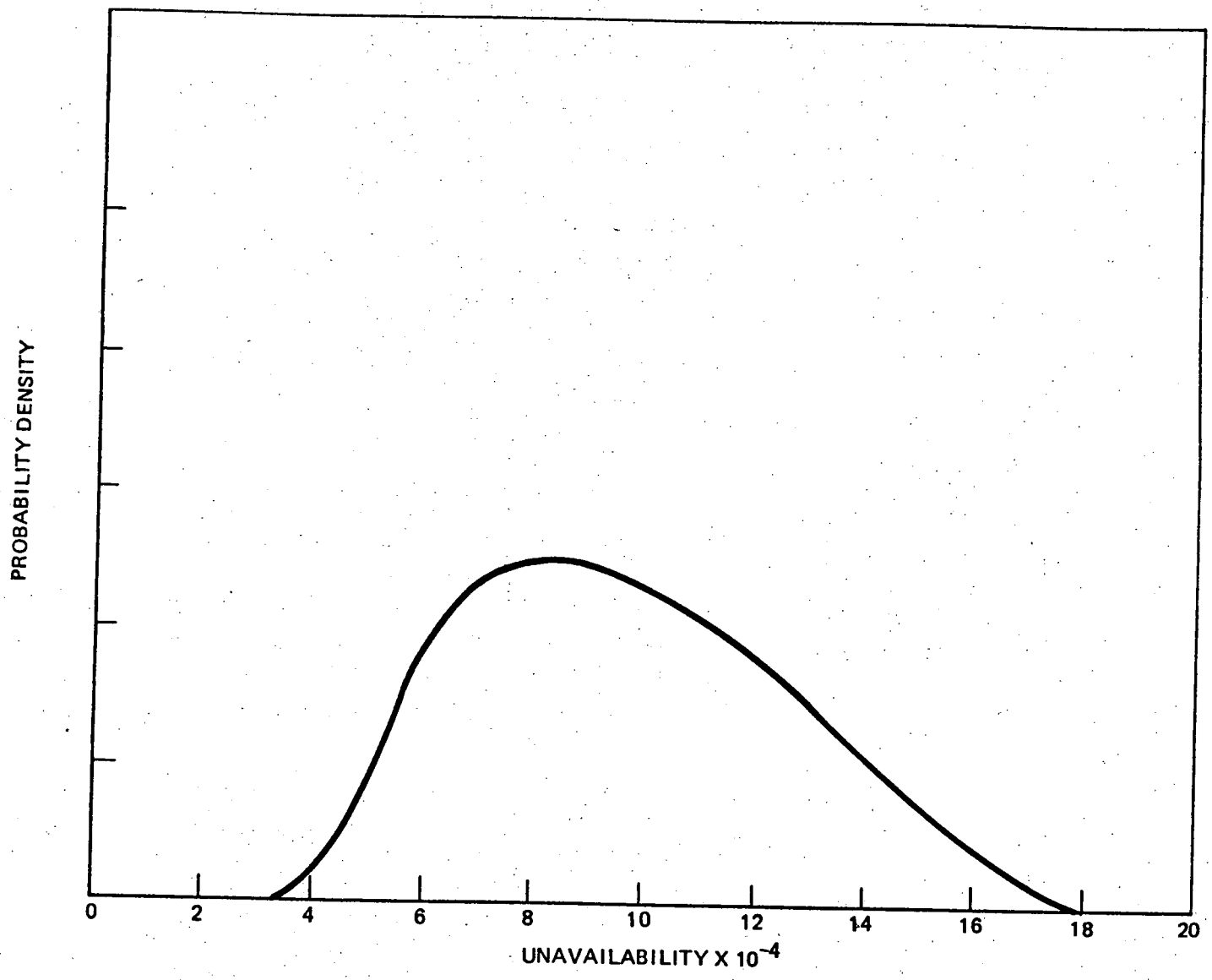

Figure 1.5.1-18. Indian Point 2 Residual Heat Removal Pumps Unavailability Due to Maintenance

(Mean = 9.73×10^{-4})

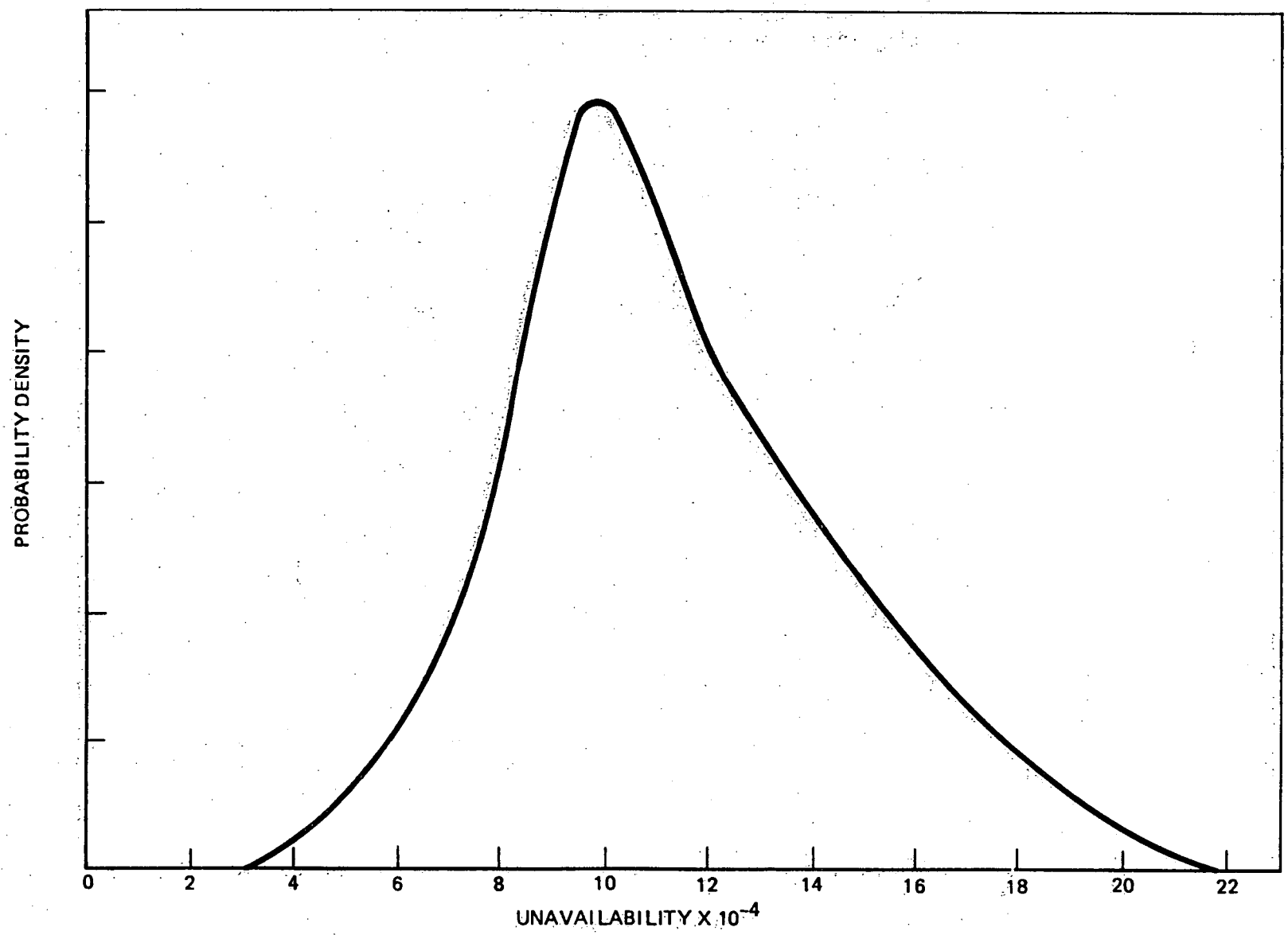

Figure 1.5.1-19. Indian Point 2 Safety Injection Pumps
Unavailability Due to Maintenance
(Mean = 1.15×10^{-3})

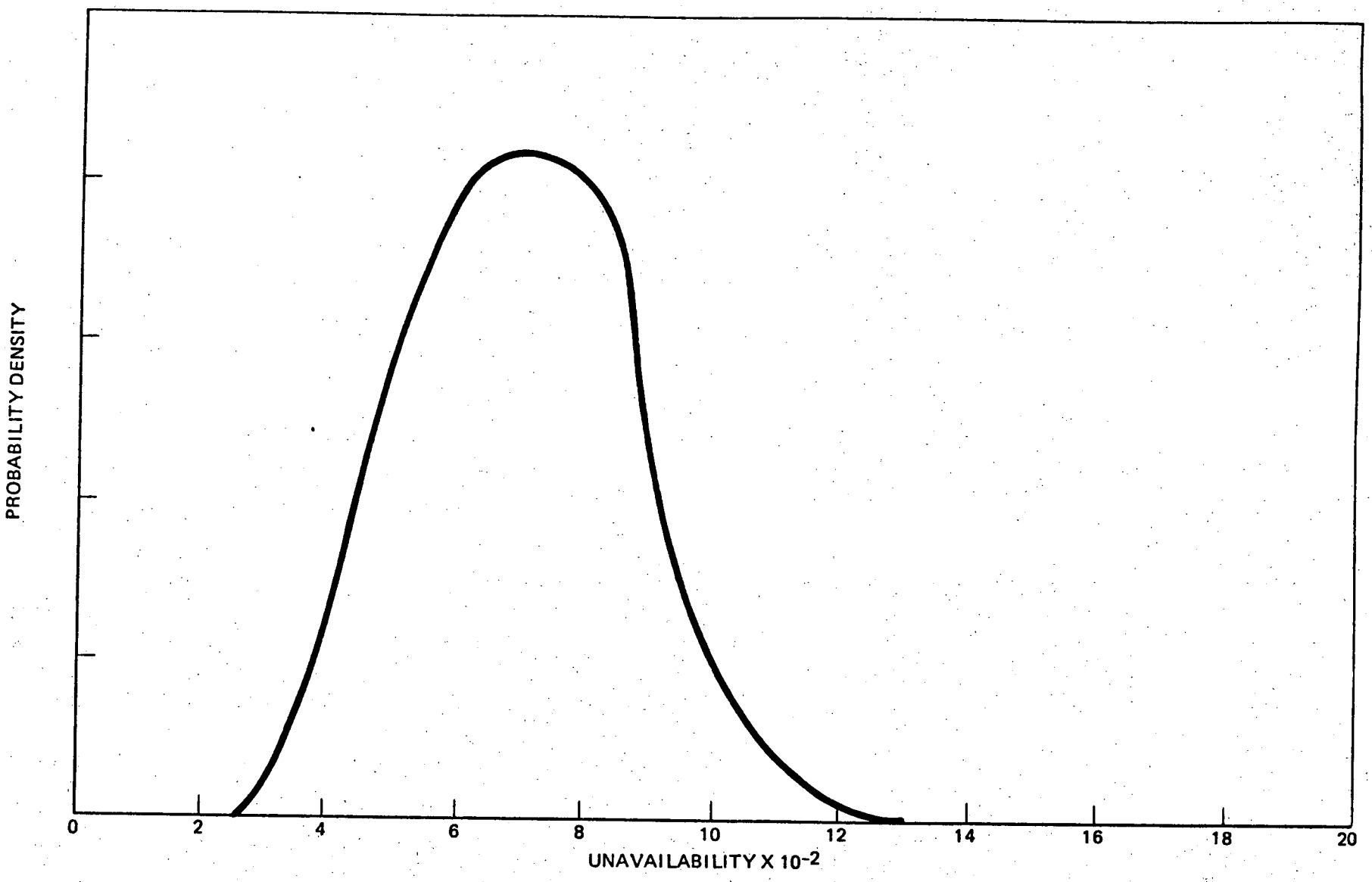

Figure 1.5.1-20. Indian Point 2 Service Water Pumps Unavailability Due to Maintenance (Mean = 6.95×10^{-2})

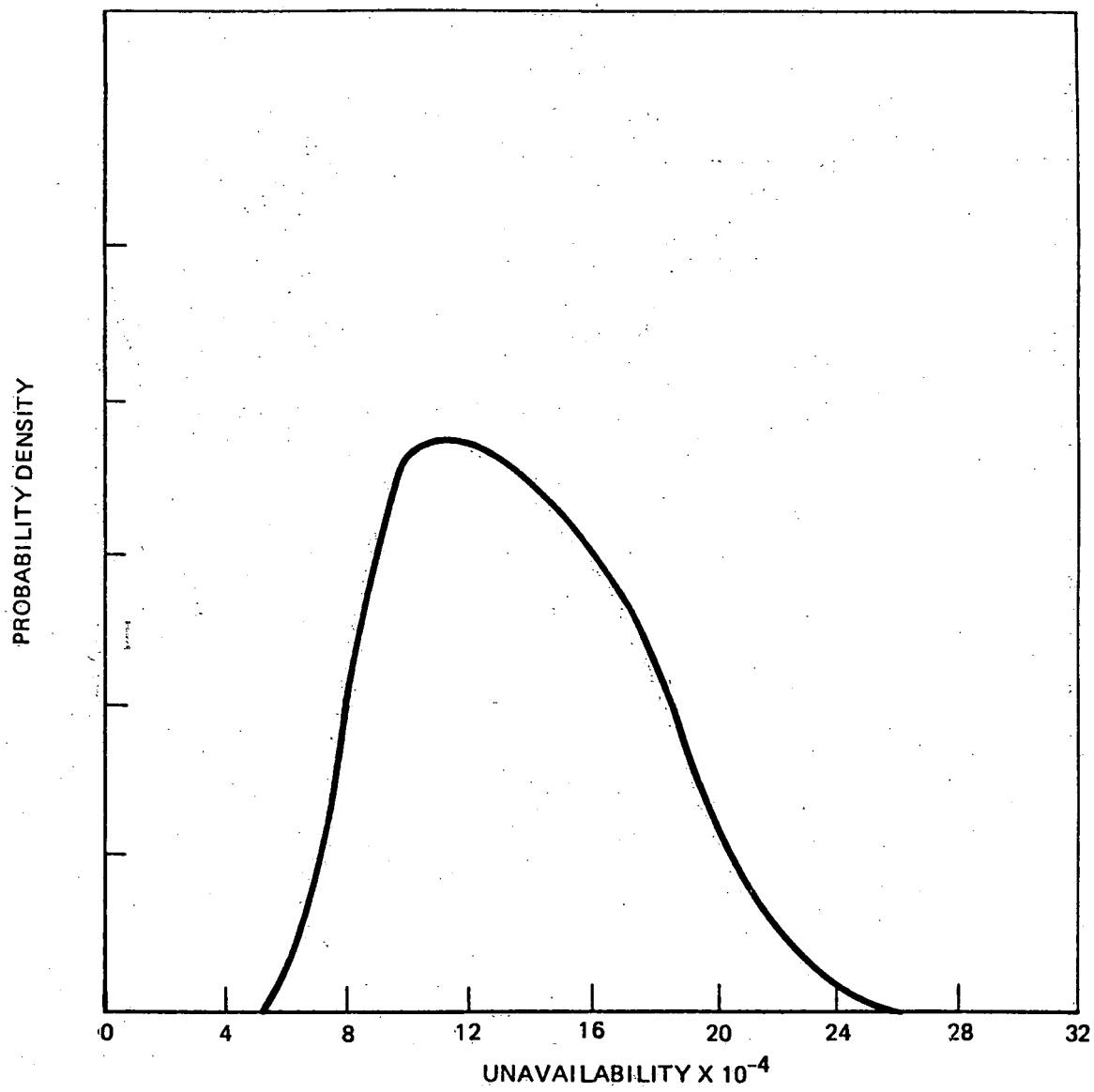

Figure 1.5.1-21. Indian Point 2 Fan Cooler Units
Unavailability Due to Maintenance
(Mean = 1.37×10^{-3})

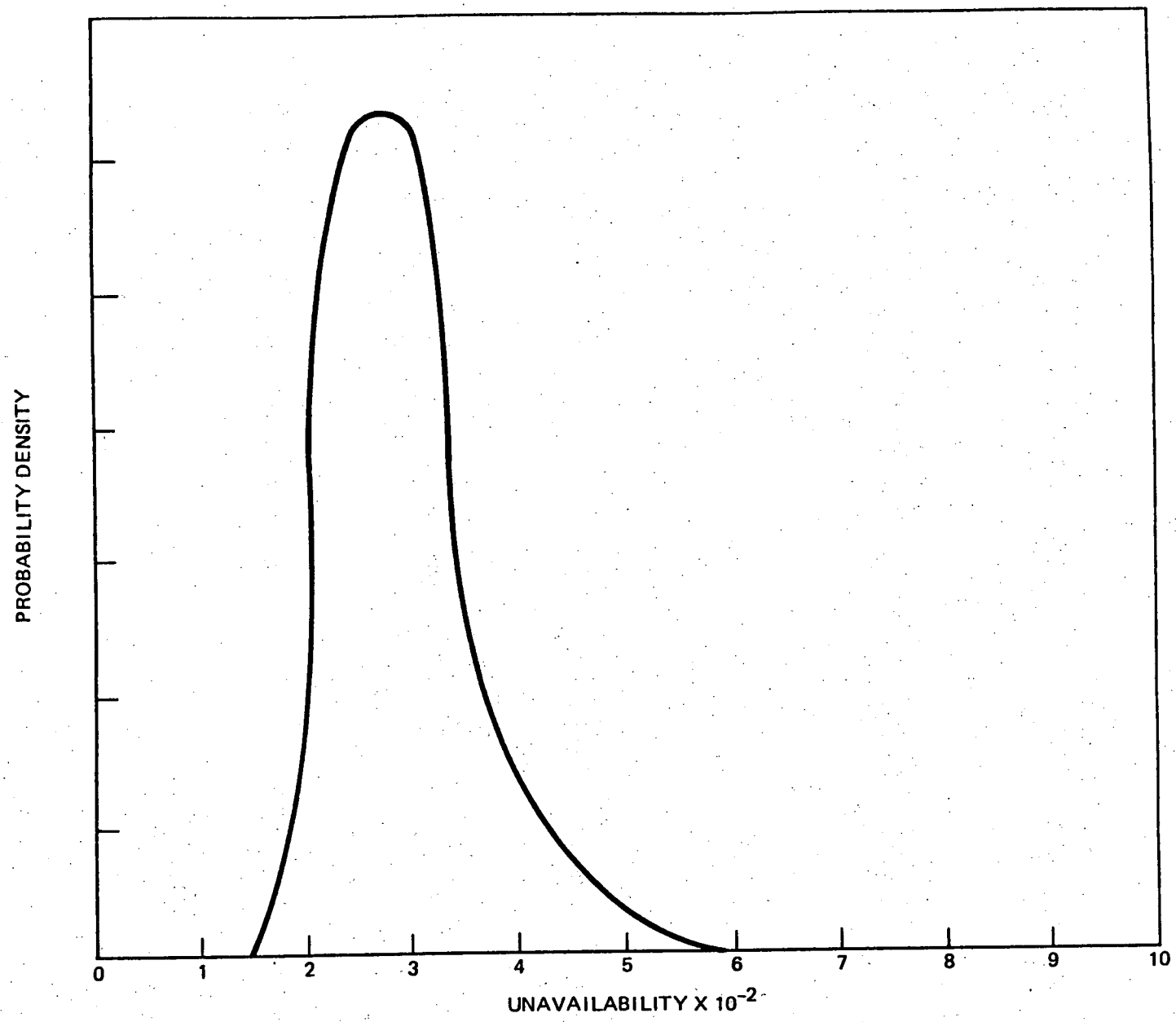

Figure 1.5.1-22. Indian Point 2 Diesel Generators Unavailability Due to Maintenance

(Mean = 3.02×10^{-2})

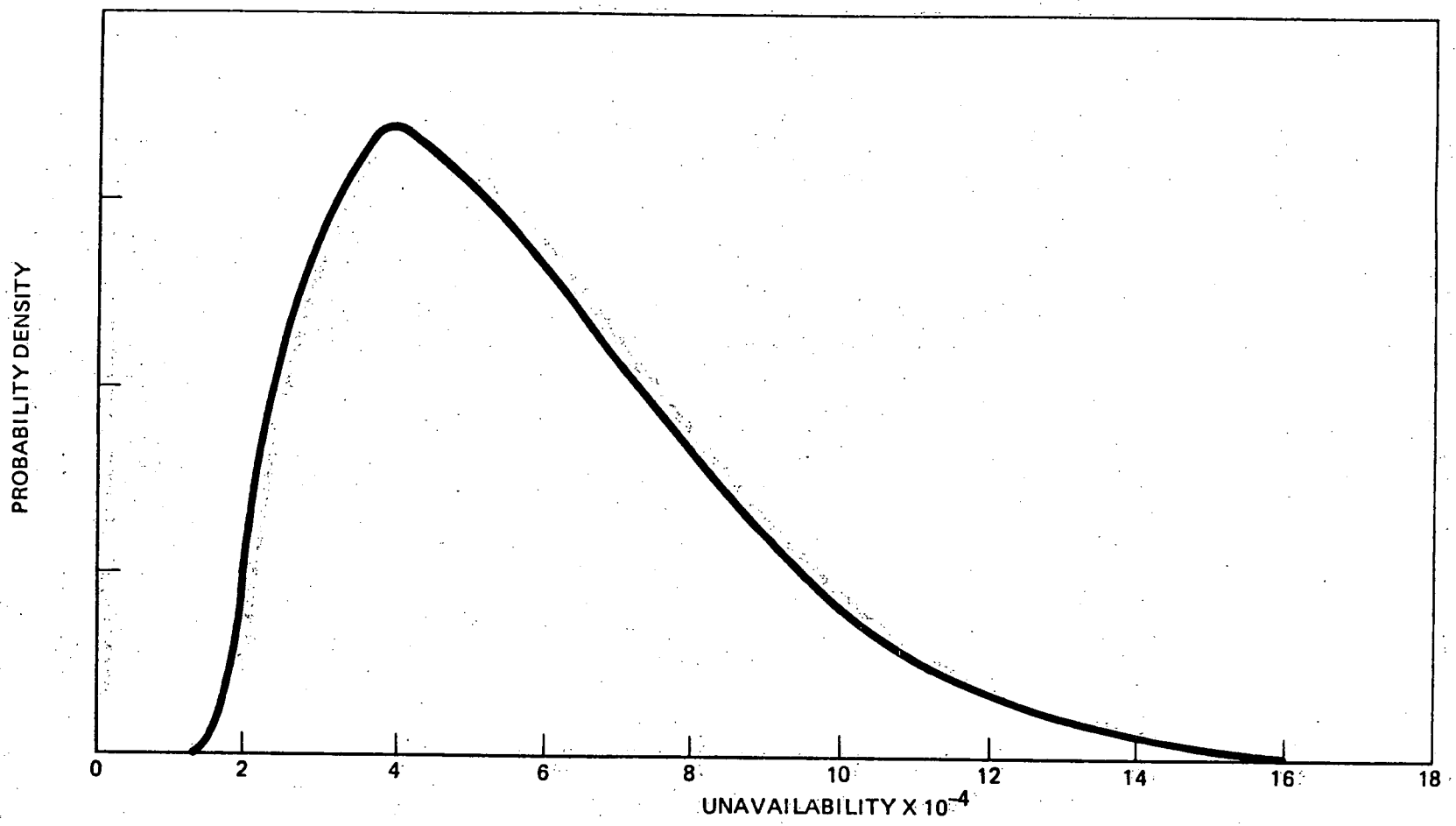

Figure 1.5.1-23. Indian Point 2 Auxiliary Component Cooling Pumps Unavailability Due to Maintenance

(Mean = 5.88×10^{-4})

1.5.1.4 Indian Point 2 Human Error Rates

1.5.1.4.1 Basic Human Error Rates

The principal source of information is the NRC human reliability handbook (Reference 1.5.1-7, which will be referred to as the handbook in the rest of this section). This work is a substantial extension of the human reliability analysis contained in the Reactor Safety Study (RSS) (Reference 1.5.1-5). It provides numbers for human error rates in numerous situations and it discusses at length the various factors that may influence human performance.

Despite the impressive amount of work that the handbook contains, the user should not forget that the numbers given are essentially the judgment of its authors and that they are not based on actual data. Therefore, judgment must also be used in applying the information in the handbook to this analysis.

For a specific human error rate the handbook usually provides a best estimate and upper and lower bounds. The use of a lognormal distribution is suggested with the two given bounds to be used as its 95th and 5th percentiles. The handbook points out that these are merely suggestions and that the users may, in some situations, wish to assign a larger uncertainty band.

In most cases, the lognormal distribution is a satisfactory distribution to use because "the performance of skilled persons tends to bunch up towards the low human error probabilities" (page 16-6 of the handbook). Unless otherwise stated, the lognormal distribution is used in this study.

The lognormal distribution is determined by using the best estimate as the median and the upper bound as the 90th percentile, rather than the 95th percentile that the handbook recommends. This is consistent with this study's approach of expressing greater uncertainty about the error rates than the generic sources of data recommend. However, because the authors of the handbook made a conscious effort not to report very low numbers, the practice in this study of using upper bounds as 80th percentiles, which was done for the data from the RSS and IEEE STD-500 (Reference 1.5.1-6), was not followed for human error rates.

Having made these decisions, the parameters μ and σ of the lognormal distribution are obtained from the equations:

$$\exp(\mu) = \text{BE (Best Estimate)} \qquad (1.5.1\text{-}2)$$

$$\exp(\mu + 1.28\sigma) = \text{UB (Upper Bound)} \qquad (1.5.1\text{-}3)$$

The solution is:

$$\mu = \ln(\text{BE}) \qquad (1.5.1\text{-}4)$$

$$\sigma = [\ln(\text{UB}) - \mu]/1.28 \qquad (1.5.1\text{-}5)$$

Example

For the rate of omission in nonpassive tasks (e.g., maintenance, test, etc.) when written procedures with checkoff provisions are used correctly, Table 15-2 of the handbook gives:

- Best Estimate (BE): 3×10^{-3}
- Lower Bound (LB): 10^{-3}
- Upper Bound (UB): 10^{-2}

when the procedure consists of more than 10 special instruction items. From Equations (1.5.1-4) and (1.5.1-5)

$$\mu = -5.31 \text{ and } \sigma = 0.94$$

Therefore,

$$\text{Mean} \equiv \alpha = \exp\left(\mu + \frac{\sigma^2}{2}\right) = 4.67 \times 10^{-3}$$

$$\text{Variance} \equiv \beta^2 = \alpha^2 \left[\exp(\sigma^2) - 1\right] = 3.08 \times 10^{-5}$$

$$\text{95th Percentile} = \exp(\mu + 1.645\sigma) = 1.41 \times 10^{-2}$$

$$\text{5th Percentile} = \exp(\mu - 1.645\sigma) = 6.40 \times 10^{-4}$$

These numbers are not very different from those of the handbook.

Following this procedure, the numbers of Table 1.5.1-22 for the human error rates, γ, that are frequently used in this study are derived.

1.5.1.4.2 Dependence

When two or more tasks are to be performed, the question of dependence between human errors must be addressed. The handbook defines five levels of dependence as follows (chapter 7 of the handbook):

1. Zero Dependence (ZD): "The quality of performance, including nonperformance, of one activity has no effect on the performance of subsequent activities."

2. Low Dependence (LD): "It is a convenient assumption to make when the dependence between actions is clearly greater than zero, but not much greater."

3. Moderate Dependence (MD): "... a level of dependence between LD and HD."

4. High Dependence (HD): "It is a convenient assumption to make when the dependence between two actions is not complete, but is definitely towards the higher end of the dependence continuum."

5. Complete Dependence (CD): "Complete dependence between the actions of two people is rare, but not as rare as ZD. CD between two actions performed by the same person is more common."

The error rate γ_N for the Nth action given failure on the (N - 1)th action is given by the following equations:

ZD: $\gamma_N = \gamma$ (the unconditional rate of Table 1.5.1-22) (1.5.1-6)

LD: $$\gamma_N = \frac{1 + 19\gamma}{20} \quad (1.5.1\text{-}7)$$

MD: $$\gamma_N = \frac{1 + 6\gamma}{7} \quad (1.5.1\text{-}8)$$

HD: $$\gamma_N = \frac{1 + \gamma}{2} \quad (1.5.1\text{-}9)$$

CD: $$\gamma_N = 1 \quad (1.5.1\text{-}10)$$

From the previous summary, it is evident that judgment needs to be exercised in deciding what the level of dependence between two specific tasks is and how these equations are to be applied.

For example, consider the tasks of successively restoring valves to their proper position after test or maintenance. For these routine actions, where written procedures are used, the level of dependence between the restoration of the first two valves is judged as moderate and the level of dependence for all other valves is complete.

Table 1.5.1-22 shows the basic error of omission by an operator (with written procedures, short list) having a median of 10^{-3} which is the best estimate listed in the handbook. It is judged that Equations (1.5.1-6) through (1.5.1-10) have been derived mainly for best estimates; i.e., the best estimate for the conditional error of omission (MD) is

$$\gamma_1^{MD} = \frac{1 + 6 \times 10^{-3}}{7} = 0.144$$

Uncertainty bounds are not given in the handbook. This uncertainty is mainly due to the use of the equation for γ_1 itself and not so much due to the variability of γ_0. If a low level of dependence is assumed, Equation (1.5.1-7) yields

$$\gamma_1^{LD} = \frac{1 + 19 \times 10^{-3}}{20} = 0.05$$

while, for a high level of dependence

$$\gamma_1^{HD} = \frac{1 + 10^{-3}}{2} = 0.50$$

Since moderate dependence is judged to be appropriate, 0.144 is used as the median of the conditional error of omission.

The uncertainty about this value is expressed by assigning an error factor of 5. The upper and lower bounds are then 0.72 and 0.029, respectively, and they include the point estimates for high and low dependencies derived previously.

The parameters μ_1 and σ_1 of the lognormal distribution of γ_1 are:

$$\mu = \ell n\ 0.144 = -\ 1.94$$

$$\sigma = \frac{\ell n 5}{1.645} = 0.98$$

The error rate for nonrestoration of two valves is given by

$$\gamma_{TV} = \gamma_1 \gamma$$

where γ_1 and γ are lognormally distributed. Consequently, γ_{TV} is also a lognormal variable with:

$$\mu = -1.94 - 6.91 = -8.85$$

$$\sigma = \sqrt{0.98^2 + 1.26^2} = 1.60$$

Therefore, the mean and variance of γ_{TV} are:

$$\alpha_{\gamma_{TV}} = 5.1 \times 10^{-4}$$

$$\beta^2_{\gamma_{TV}} = 3.1 \times 10^{-6}$$

and the percentiles are:

5th percentile:	10^{-5}
Median:	1.4×10^{-4}
95th percentile:	2.0×10^{-3}

1.5.1.4.3 High Stress Situations

The numbers that have been presented apply to normal tasks. When a high stress situation exists; e.g., following a loss of coolant accident, the response of the operators depends strongly on the time available, the information that they have, etc. These special cases are analyzed where they arise; e.g., in the analysis of the recirculation system, in the fire analysis, and elsewhere in this study.

TABLE 1.5.1-22

BASIC HUMAN ERROR RATES
(Per Demand)

Task	NRC Handbook*	This Study			
		μ	σ	Mean	Variance
ERRORS OF COMMISSION					
1. Change or tag wrong valve where the desired valve is one of two or more adjacent, similar appearing manual valves, and at least one other valve is in the same state as the desired valve, or the valves are MOVs of such type that valve status cannot be determined at the valve itself.	$5x10^{-3}$ ($2x10^{-3}$ - $2x10^{-2}$)	-5.30	1.08	$9x10^{-3}$	$1.8x10^{-4}$
2. Change or restore wrong MOV switch or circuit breaker in a group of similar appearing items (in case of restoration, at least two items are tagged).	$3x10^{-3}$ (10^{-3} - 10^{-2})	-5.81	0.94	$4.7x10^{-3}$	$3.1x10^{-5}$
3. General error of commission in nonpassive tasks such as maintenance, test, or calibration when written procedures are used.	$3x10^{-3}$ (10^{-3} - 10^{-2})	-5.81	0.94	$4.7x10^{-3}$	$3.1x10^{-5}$
ERRORS OF OMISSION					
1. Nonpassive tasks (maintenance, test, calibration); using procedures with checkoff provisions.					
i. Short list (≤ 10 special instruction items).	10^{-3} ($5x10^{-4}$ - $5x10^{-3}$)	-6.91	1.26	$2.2x10^{-3}$	$1.9x10^{-5}$
ii. Long list (> 10 special instruction items).	$3x10^{-3}$ (10^{-3} - 10^{-2})	-5.81	0.94	$4.7x10^{-3}$	$3.1x10^{-5}$
2. Passive tasks such as walk-around inspections.					
i. Failure to recognize an incorrect status when checking each item as it is looked at.	10^{-2} ($5x10^{-3}$ - $5x10^{-2}$)	-4.61	1.21	$2.2x10^{-2}$	$1.9x10^{-3}$
ii. Failure to recognize an incorrect status when checking off several items after looking at several.	10^{-1} ($5x10^{-2}$ - $5x10^{-1}$)	-2.30	1.26	$2.2x10^{-1}$	$1.9x10^{-1}$

*Best Estimate (Range)

1.5.1.5 Initiating Events Discussion and Quantification

1.5.1.5.1 Initiating Events. Discussion of the Plant Specific and Pressurized Water Reactor (PWR) Population Data

This section describes how the plant specific and the PWR population initiating event data were obtained and provides a detailed description of the plant specific initiating events used in this study.

1.5.1.5.2 Plant Specific Initiating Event Data

The plant monthly operating reports and the Nuclear Regulatory Commission's "Operating Units Status Reports" (the "Grey Books"), Reference 1.5.1-8, were reviewed from the plant's commercial operation date* through December 1979. In order to keep the plant specific and the population data consistent, the plant specific data were collected by operational year (instead of calendar year) as was done with the population data in Reference 1.5.1-9. The first operational year is defined as the "in-service date and subsequent 364 days," page 3-3, Reference 1.5.1-9.

The data thus collected were grouped according to the initiating event subcategories listed in Table 1.5.1-23. The subcategory data were then gathered into the categories shown in Table 1.5.1-24. Detailed descriptions of the initiating events used in this study are listed, category by category, in Tables 1.5.1-25 through 1.5.1-29.

1.5.1.5.3 PWR Population Initiating Event Data

Most of the PWR population data was obtained from Tables 1 through 41, pages B-3 through B-44, of Reference 1.5.1-9, EPRI NP-801.

The following PWRs which were not included in Reference 1.5.1-9, were added to the data base used in this study:

- Indian Point 3
- Zion 1
- Zion 2
- D. C. Cook
- Prairie Island 1
- Prairie Island 2
- Turkey Point 3
- Turkey Point 4

Furthermore, 4 operational years of data were added to the Indian Point 2 values originally listed in Reference 1.5.1-9.

A list of all the plants which compose the population data base is shown in Table 1.5.1-30.

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*July 1, 1974, for Indian Point 2.

Table 1.5.1-31 shows how the 41 transient categories in the EPRI NP-801 report were grouped into the 12 initiating event categories used in this project.

1.5.1.5.4 Results

The plant specific and the population data are summarized in Table 1.5.1-32 by plant and by initiating event. Table 1.5.1-33 shows the number of operational years in the data base, by plant.

Finally, Table 1.5.1-34 shows the probability of occurrence of each initiating event expressed in terms of various lognormal parameters for the plant specific and PWR population generic data.

TABLE 1.5.1-23

INDIAN POINT 2 INITIATING EVENT SUBCATEGORIES

1. Large Loss of Coolant Accidents (LOCAs)

2. Medium LOCAs

3. Small LOCAs

   a. Pressurizer relief or safety valve opening
   b. Miscellaneous small LOCAs

4. Steam Generator Tube Rupture

5. Steam Pipe Rupture Inside the Containment

6. Steam Pipe Rupture Outside the Containment

7. Loss of Feedwater Flow

   a. Loss/reduction of feedwater flow in one steam generator
   b. Loss of feedwater flow in all steam generators
   c. Feedwater flow instability--operator error
   d. Feedwater flow instability--mechanical causes
   e. Loss of one condensate pump
   f. Loss of all condensate pumps
   g. Condenser leakage
   h. Miscellaneous secondary leakage

8. Full or Partial Closure of One Main Steam Isolation Valve (MSIV)

9. Loss of Primary Flow

   a. Loss of primary flow in one loop
   b. Loss of primary flow in all loops

10. Core Power Increase

   a. Uncontrolled rod withdrawal
   b. Boron dilution--chemical and volume control system malfunction
   c. Cold water addition

TABLE 1.5.1-23 (continued)

INDIAN POINT 2 INITIATING EVENT SUBCATEGORIES

11. Turbine Trip

    a. Turbine trip

        1. Closure of all main steam isolation valves
        2. Increase in feedwater flow in one steam generator
        3. Loss of condenser vacuum
        4. Loss of circulating water
        5. Throttle valve closure/electro-hydraulic control problems
        6. Generator trip or generator caused faults
        7. Increase in feedwater flow in all steam generators

    b. Turbine trip due to loss of offsite power
    c. Turbine trip due to loss of service water

12. Reactor Trip

    a. Reactor trip

        1. Control rod drive mechanism problems and/or rod drop
        2. High or low pressurizer pressure
        3. Spurious automatic trip--no transient condition
        4. Automatic/manual trip--operator error
        5. Manual trip due to false signal
        6. Spurious trip--cause unknown
        7. Primary system pressure, temperature, power imbalance
        8. Loss of power to necessary plant systems
        9. Spurious safety injection activation

    b. Reactor trip due to loss of component cooling water

TABLE 1.5.1-24

INDIAN POINT 2 INITIATING EVENT CATEGORIES

1. Large Loss of Coolant Accidents (LOCAs)
2. Medium LOCAs
3. Small LOCAs
4. Steam Generator Tube Rupture
5. Steam Pipe Rupture Inside the Containment
6. Steam Pipe Rupture Outside the Containment
7. Loss of Feedwater
8. Full or Partial Closure of One Main Steam Isolation Valve
9. Loss of Primary Flow
10. Core Power Increase
11. Turbine Trip
    a. Turbine trip (other than loss of service water or offsite power)
    b. Turbine trip due to loss of offsite power
    c. Turbine trip due to loss of service water
12. Reactor Trip
    a. Reactor trip (other than loss of component cooling water)
    b. Reactor trip due to loss of component cooling water

TABLE 1.5.1-25

INDIAN POINT 2 INITIATING EVENTS CATEGORY 7: LOSS OF FEEDWATER FLOW

Date Day/Month/Year	Event Description
02/07/74	Main steam generator feed pump tripped due to oil leakage at loose coupling on control oil header--low level steam generator
31/08/74	Spurious trip of main steam generator feed pump 21--low level
28/11/74	Lost main boiler feed pump 21 causing steam generator mismatch
03/12/74	Operator accidentally hit trip level on main boiler feed pump--steam generator 21 mismatch
15/12/74	Governor torque motor grounded causing main boiler feed pump 22 to run down, resulting in a steam generator 21 mismatch trip
05/01/75	Low level on steam generator caused by loss of heater drain pump
13/07/75	Unit trip due to steam generator low level mismatch caused by overspeed trip of main boiler feed pump
22/08/75	Reactor trip due to steam generator mismatch--assumed low level
29/08/75	Reactor trip due to steam generator low level with steam flow feedwater flow mismatch
07/09/75	Reactor tripped due to steam generator low level mismatch caused by trip of main boiler feed pump
29/09/75	Reactor trip due to low-low level in steam generator 23 due to failed feedwater regulating valve (broken air line)
04/10/75	Turbine trip-boiler feed pump control trouble
09/11/75	Unit tripped due to steam generator low level mismatch--caused by loss of condensate pump 23

TABLE 1.5.1-25 (continued)

INDIAN POINT 2 INITIATING EVENTS CATEGORY 7: LOSS OF FEEDWATER FLOW

Date Day/Month/Year	Event Description
27/11/75	Unit tripped due to steam generator mismatch caused by control failure of heater drain tank pump level control valve
28/11/75	Steam generator mismatch (poor feedwater control at low levels)
28/11/75	Steam generator mismatch (poor feedwater control at low levels)
13/12/75	Unit trip due to steam generator low level mismatch
27/12/75	Unit trip due to steam generator low level caused by condensate pump deterioration
28/02/76	Reactor trip due to steam generator 24 low level and steam flow/feed flow mismatch
23/12/76	Unit trip due to steam generator 23 low level and feedwater/steam flow mismatch
06/02/77	Low-low level on steam generator 23
26/05/77	Steam generator 24 feedwater flow/steam flow mismatch trip during startup
14/06/77	Low output from lube oil pump for main boiler feed pump
26/06/78	Steam generator low level--spurious signal--opened heater drain tank condenser dump valves resulting in a steam generator low level
07/07/78	Steam generator feed flow steam flow mismatch
28/07/78	Main boiler feed pump 21 stop valve closure caused by short circuit in valve wiring

TABLE 1.5.1-25 (continued)

INDIAN POINT 2 INITIATING EVENTS CATEGORY 7: LOSS OF FEEDWATER FLOW

Date Day/Month/Year	Event Description
15/02/79	Boiler feed pump header nipple leak
16/02/79	Main boiler feedwater pump oil pump
26/02/79	Steam generator 24 feedwater regulator transferred closed
27/02/79	Steam generator 24 feedwater regulator transferred closed
23/04/79	Malfunction of condenser steam dump system
18/09/79	Loss of main boiler feedwater pump 21
23/09/79	Main boiler feedwater pump 22 recirculation drain valve
25/09/79	Steam generator 22 regulator valve
01/12/79	Unit trip due to feed regulator--low level in steam generator 23

TABLE 1.5.1-26

INDIAN POINT 2 INITIATING EVENTS
CATEGORY 8: FULL OR PARTIAL CLOSURE OF ONE MSIV

Date Day/Month/Year	Event Description
22/07/74	Truck driver performed valving to change nitrogen tank trucks--low pressure resulted in main steam isolation valve closure which caused reactor trip on low-low level in steam generator 24
08/08/74	Low drum level caused by main steam isolation valve closure
12/08/75	Reactor trip due to low level mismatch on steam generator 22 caused by main steam valve closing
13/08/75	Reactor trip due to low level mismatch on steam generator 22 caused by main steam valve closing
11/10/75	Turbine trip--steam generator low level due to main steam isolation valve closure
23/12/75	Steam generator low level due to main steam line isolation valve closing
27/01/77	Main steam isolation valve closure due to inadvertent closure of air supply solenoid valve

TABLE 1.5.1-27

INDIAN POINT 2 INITIATING EVENTS CATEGORY 11A: TURBINE TRIP

Date Day/Month/Year	Event Description
02/07/74	Repair malfunction of feedwater regulator--high level in steam generator 24
06/08/74	High drum level on steam generator 22 due to feedwater control problems at low loads
13/09/74	Trip due to feedwater control problems at low loads--high level steam generator
13/09/74	Trip due to feedwater control problems at low loads--high drum level
14/09/74	Turbine governor failure caused large load swings resulting in trip--unit trip on over power
27/09/74	Trip resulted from electrical fault external to plant which opened generator output breakers
07/11/74	Trip due to transient during 3 loop operation--high level in steam generator
06/04/75	Automatic trip due to turbine governor control valve not responding
18/05/75	Trip due to high level on steam generator
30/06/75	Unit tripped due to inadvertent closing of one turbine stop valve
20/07/75	Unit tripped due to system disturbance which affected the instrument buses--fallen wire due to storm--generator trip
17/08/75	Turbine trip due to high level on steam generator
17/08/75	Turbine trip due to high level on steam generator
05/10/75	Turbine trip--steam generator high level

TABLE 1.5.1-27 (continued)

INDIAN POINT 2 INITIATING EVENTS CATEGORY 11A: TURBINE TRIP

Date Day/Month/Year	Event Description
16/10/75	Generator trip--generator fault
31/10/75	Unit trip--steam generator high level
17/11/75	Unit tripped due to high level in steam generator
23/12/75	Unit tripped due to steam generator high level
23/12/75	Unit tripped due to steam generator high level
06/01/76	Unit trip from high level in steam generator 21
26/01/76	Unit trip from high level in steam generator 21
26/01/76	Unit trip from high level in steam generator 24
27/02/76	Failure of relays in the turbine redundant overspeed protection system
09/03/76	Unit trip due to high level on steam generator 24--valves in bypass line had been opened
27/12/76	Unit trip due to steam generator 24 high level
31/12/76	Unit trip due to steam generator 21 high level
15/03/77	High steam generator level due to poor response of level controller
15/03/77	High steam generator level due to stuck regulating valve
01/07/77	Unit trip, relay protection control circuit fault at Buchanan substation
08/08/77	Unit trip--loss of exciter
15/08/77	"A" phase bushing on main transformer 21 failed
17/10/77	High vibration on turbine bearing 11
26/05/78	High level on the steam generator 21
28/02/79	Steam generator 22 high level

TABLE 1.5.1-27 (continued)

INDIAN POINT 2 INITIATING EVENTS CATEGORY 11A: TURBINE TRIP

Date Day/Month/Year	Event Description
12/04/79	Spurious main steam isolation valve closure signal
15/09/79	Steam generator 24 high level
15/09/79	Steam generator 23 high level
19/09/79	Steam generator 21 high level
21/09/79	Turbine overspeed test

TABLE 1.5.1-28

INDIAN POINT 2 INITIATING EVENTS CATEGORY 11B: TURBINE TRIP DUE TO LOSS OF OFFSITE POWER*

Date Day/Month/Year	Event Description
03/06/80	Unit trip, loss of offsite power (Buchanan substation)

*Included in the data base were 6 operational years as compared to 5 operational years for all other initiating events.

TABLE 1.5.1-29

INDIAN POINT 2 INITIATING EVENTS CATEGORY 12A: REACTOR TRIP

Date Day/Month/Year	Event Description
03/07/74	Repaired loose terminal block connection for loop 22 cold leg temperature input--over power, over temperature
04/07/74	Repaired loose connection on loop 24 cold leg resistance temperature detector amplifier--over power, over temperature
26/07/74	Perform 100 percent plant trip test and scheduled maintenance
08/08/74	Trip due to inability of reactor operator to make load changes carefully in order to avoid having insufficient reactivity to keep up with xenon burnout--over power, over temperature
03/09/74	Steam generator mismatch signal caused trip due to reactor trip due to failure of static inverter 21
13/09/74	Trip due to operator inability to make load changes more carefully in order to avoid having insufficient reactivity to keep up with xenon burnout--over power, over temperature
30/09/74	Maintenance and seismic pipe restraints inspection - Unit trip due to spurious signal on loop 24 flow instrument which led to low reactor coolant system flow (1 loop)
06/11/74	Trip due to shorted test lead on hot leg 21 resistance temperature detector--unit trip on overpower
13/11/74	Inverter failed--switched instrument bus to backup--unit trip due to low level and low pressure--caused spurious safety injection signal
02/12/74	Electrical system disturbance caused drop in instrument bus voltage--unit trip due to steam generator 21 mismatch
08/12/74	Spurious signal on steam generator level channel - Low level

TABLE 1.5.1-29 (continued)

INDIAN POINT 2 INITIATING EVENTS CATEGORY 12A: REACTOR TRIP

Date Day/Month/Year	Event Description
11/02/75	Electrical problem at substation due to substation repair crew causing feeder relay actuation
02/06/75	Unit trip due to loss of electrical feeder, due to a human error
19/06/75	Unit tripped due to a steam generator low level and steam flow/feedwater flow mismatch as a result of failure of static inverter which feeds instrument bus
27/06/75	Unit tripped due to steam generator low level and steam flow/feedwater flow mismatch caused by switching of level control channel during periodic testing
28/07/75	Automatic reactor trip while shutting down for schdeuled maintenance
14/08/75	Reactor trip due to spurious over-power delta temperature protection signal
22/08/75	Reactor trip due to safety injection signal caused by low t_{avg} and spurious high steam flow signal
30/09/76	Checked setting of turbine mechanical overspeed trip mechanism
17/12/76	Spurious reactor protection trip signal
21/12/76	Spurious loss of loop flow signal--cause unknown
23/12/76	Incorrect indication of loss of 6.9 kV bus due to personnel error while performing test
27/12/76	Reactor trip due to steam generator 24 low-low level as a result of personnel error during a test
09/02/77	During periodic surveillance test of the diesel generators, operator failed to synchronize the diesel generators to the 480V buses before opening their normal power supply breakers--safety injection activation

TABLE 1.5.1-29 (continued)

INDIAN POINT 2 INITIATING EVENTS CATEGORY 12A: REACTOR TRIP

Date Day/Month/Year	Event Description
13/02/77	Loss of flow signal on single loop--cause not identified
14/02/77	Loss of flow signal on single loop--caused by defective Westinghouse BFD delays
11/03/77	Automatic reactor trip while shutting down for scheduled maintenance
26/05/77	Erroneous single loop-loop flow signal--tightened packing on instrument isolation valves
26/05/77	Single loop loss of flow--occurred during process of tightening packing on instrument isolation valves
11/08/77	Reactor trip--spurious overpower hi-flux trip via nuclear instrumentation channel 3
17/08/77	Reactor trip--spurious overtemperature--due to inadvertant operation of static inverter 21 during DC lube oil pump test
26/09/77	Spurious reactor trip caused by disturbance on transmission distribution system
11/10/77	Trip due to erroneous reactor coolant pump 21 breaker open signal
07/07/78	Faulty contactor in reactor trip breaker
15/02/79	Spurious signal to reactor trip breaker
09/03/79	Static inverter 23 resulted in steam flow/feedwater flow mismatch trip and a safety injection activation

TABLE 1.5.1-30

INDIAN POINT 2 PWR PLANTS INCLUDED IN THE POPULATION DATA BASE

Yankee Rowe
Indian Point 1
San Onofre
Connecticut Yankee
R. E. Ginna
H. B. Robinson
Point Beach 1
Point Beach 2
Palisades
Main Yankee
Surry 1
Surry 2
Oconee 1
Oconee 2
Oconee 3
Fort Calhoun
Kewaunee
Arkansas 1
Three-Mile Island 1
Calvert Cliffs
Trojan
Millstone 2
Zion 1 plus Zion 2
Indian Point 2
Indian Point 3
D. C. Cook 1
Prairie Island 1
Prairie Island 2
Turkey Point 3
Turkey Point 4

TABLE 1.5.1-31

INDIAN POINT 2 SOURCES OF POPULATION DATA BY INITIATING EVENT SUBCATEGORY

Plant Specific Initiating Event Category	Population Initiating Event Category Population Data was Obtained from EPRI NP-801* (ATWS: A Reappraisal Part III - Frequency of Anticipated Transients) Categories
1. Large Loss of Coolant Accidents	None
2. Medium Loss of Coolant Accidents	None
3. Small Loss of Coolant Accidents:	
a. Pressurizer relief or safety valve opening	8. Pressurizer Relief or Safety Valve Opening. This transient occurs when hardware or operator error results in inadvertent opening of pressurizer relief or safety valves.
b. Miscellaneous small LOCAs	None
4. Steam Generator Tube Rupture	26. Steam Generator Leakage. This transient occurs when excessive primary system to secondary leakage occurs in the steam generator.
5. Steam Pipe Rupture Inside the Containment	None
6. Steam Pipe Rupture Outside the Containment	None
7. Loss of Feedwater Flow:	
a. Loss/reduction of feedwater flow in one	15. Loss or Reduction in Feedwater Flow (1 loop) Steam Generator. This transient occurs when one feedwater pump trips or when another occurrence results in an overall decrease in feedwater flow.
b. Loss of feedwater flow in all steam generators	16. Total Loss of Feedwater Flow (all loops). This transient occurs when a simultaneous loss of all main feedwater occurs, excluding that due to loss of station power (definition 35).
c. Feedwater flow instability--operator error	21. Feedwater Flow Instability--Operator Error. This transient occurs when feedwater is being controlled manually, usually during startup or shutdown, and excessive or insufficient feedwater flow occurs.
d. Feedwater flow instability--mechanical causes	22. Feedwater Flow Instability--Miscellaneous Mechanical Causes. This transient occurs when excessive or insufficient feedwater flow results from hardware failures in the feedwater system.
e. Loss of one condensate pump	23. Loss of Condensate Pumps (1 loop). This transient occurs when one condensate pump fails, reducing feedwater flow.
f. Loss of all condensate pumps	24. Loss of Condensate Pumps (all loops). This transient occurs when all condensate pumps fail, causing a loss of feedwater flow.
g. Condenser leakage	27. Condenser Leakage. This transient occurs when excessive secondary system leakage occurs in the condenser.
h. Miscellaneous secondary system leakage	28. Miscellaneous Leakage in Secondary System. This transient occurs when excessive leakage occurs in the secondary system, other than the condenser (see definition 27).

*The following EPRI categories were not considered applicable to this study: 4, 5, 7, 10, and 29. Category 41 was handled separately in Section 7.0.

TABLE 1.5.1-31 (continued)

INDIAN POINT 2 SOURCES OF POPULATION DATA BY INITIATING EVENT SUBCATEGORY

Plant Specific Initiating Event Category	Population Initiating Event Category Population Data was Obtained from EPRI NP-801* (ATWS: A Reappraisal Part III - Frequency of Anticipated Transients) Categories
8. Full or Partial Closure of One Main Steam Isolation Valve	17. Full or Partial Closure of MSIV (1 loop). This transient occurs when one main steam isolation valve (MSIV) closes, the rest remaining open, or the partial closure of one or more MSIVs occurs.
9. Loss of Primary Flow:	
a. Loss of primary flow in one loop	1. Loss of RCS Flow (1 loop). This transient occurs when an inadvertent hardware or human error interrupts the flow in one loop of the reactor coolant system.
b. Loss of primary flow in all loops	14. Total Loss of RCS Flow. This transient occurs when a hardware or operator error causes a loss of reactor coolant system flow.
10. Core Power Increase:	
a. Uncontrolled rod withdrawal	2. Uncontrolled Rod Withdrawal. This transient occurs when one or more control rods are withdrawn inadvertently.
b. Boron dilution--chemical and volume control system malfunction	11. CVCS Malfunction--Boron Dilution. This transient occurs when hardware or operator error results in a CVCS malfunction such that reactor power is affected.
c. Cold water addition	13. Startup of Inactive Coolant Pump. This transient occurs when an idle coolant pump is started at an improper power and flow condition.
11. Turbine Trip:	
a. Turbine Trip:	
(1) Closure of all main steam isolation valves	18. Closure of All MSIVs. This transient occurs when any one of various steam line or nuclear system malfunctions requires termination of steam flow from the vessel, or by operator action.
(2) Increase in feedwater flow in one steam generator	19. Increase in Feedwater Flow (1 loop). This transient occurs when an increase in feedwater flow occurs in one loop.
(3) Loss of condenser vacuum	25. Loss of Condenser Vacuum. This transient occurs when either a complete loss or decrease in condenser vacuum results from a hardware or human error.
(4) Loss of circulating water	30. Loss of Circulating Water. This transient occurs when circulating water is not available to the plant.
(5) Throttle valve closure/electro-hydraulic control problems	33. Turbine Trip, Throttle Valve Closure, EHC Problems. This transient occurs when a turbine trip occurs, or if turbine problems occur which, in effect, decrease steam flow to the turbine, causing a rapid change in the amount of energy removed from the primary system.

*The following EPRI categories were not considered applicable to this study: 4, 5, 7, 10, and 29. Category 41 was handled separately in Section 7.0.

TABLE 1.5.1-31 (continued)

INDIAN POINT 2 SOURCES OF POPULATION DATA BY INITIATING EVENT SUBCATEGORY

Plant Specific Initiating Event Category	Population Initiating Event Category Population Data was Obtained from EPRI NP-801* (ATWS: A Reappraisal Part III - Frequency of Anticipated Transients) Categories
(6) Generator trip or generator-caused faults	34. Generator Trip or Generator-Caused Faults. This transient occurs when the generator is tripped due to electrical grid disturbances or generator faults.
(7) Increase in feedwater flow in all steam generators	20. Increase in Feedwater Flow (all loops). This transient occurs when an increase in feedwater flow occurs in more than one loop.
b. Turbine trip due to loss of offsite power	35. Loss of Station Power. This transient occurs when all power to the plant from external sources (the grid or a dedicated transmission line to another plant) is lost.
c. Turbine trip due to loss of service water	32. Loss of Service Water System. This transient occurs when the service water system fails to perform its function.
12. Reactor Trip:	
a. Reactor trip:	
(1) Control rod drive mechanism problems and/or rod drop	3. CRDM Problems and/or Rod Drop. This transient occurs when failures in the control rod drive mechanism (CRDM) occur which lead to out of tolerance conditions in the primary system. The transient may include dropping of one or more control rods into the core as part of the CRDM failure.
(2) High or low pressurizer pressure	6. High or Low Pressurizer Pressure. This transient occurs when the pressurizer pressure is outside of the required operating limits.
(3) Spurious automatic trip--no transient condition	37. Spurious Auto Trip--No Transient Condition. This transient occurs when an auto scram is initiated by a hardware failure in instrumentation or logic circuits and no out-of-tolerance condition exists.
(4) Automatic/manual trip--operator error	38. Auto/Manual Trip Due to Operator Error. This transient occurs when an auto scram or manual scram is initiated by human error and no out-of-tolerance condition exists.
(5) Manual trip due to false signal	39. Manual Trip Due to False Signals. This transient occurs when an operator initiates a scram based on information from erroneous instrumentation.
(6) Spurious trip--cause unknown	40. Spurious Trips--Cause Unknown. This transient occurs when a scram occurs and no out-of-tolerance condition can be detected, nor cause of scram determined.

*The following EPRI categories were not considered applicable to this study: 4, 5, 7, 10, and 29. Category 41 was handled separately in Section 7.0.

TABLE 1.5.1-31 (continued)

INDIAN POINT 2 SOURCES OF POPULATION DATA
BY INITIATING EVENT SUBCATEGORY

Plant Specific Initiating Event Category	Population Initiating Event Category Population Data was Obtained from EPRI NP-801* (ATWS: A Reappraisal Part III - Frequency of Anticipated Transients) Categories
(7) Primary system pressure, temperature, power imbalance	12. Pressure, Temperature, Power Imbalance. This transient occurs when various primary systems signals indicate pressure, temperature or power imbalances.
(8) Loss of power to necessary plant systems	36. Loss of Power to Necessary Plant Systems. This transient occurs when power is lost to a component or group of components such that plant shutdown is necessary. It does not include loss of power to those components whose failure causes another defined transient to occur.
(9) Spurious Safety Injection Activation	9. Inadvertent Safety Injection Signal. This transient occurs when hardware or operator error initiates a safety injection.
b. Reactor trip due to loss of component cooling water	31. Loss of Component Cooling. This transient occurs when excessive temperature of critical components is a result of a loss or decrease in component cooling water flow.

*The following EPRI categories were not considered applicable to this study: 4, 5, 7, 10, and 29. Category 41 was handled separately in Section 7.0.

TABLE 1.5.1-32

INDIAN POINT 2 POPULATION EVENT DATA

PWR PLANT NAME	1 Large Loca	2 Medium Loca	3 Small Loca	4 S/G Tube Rupture	5 Steam Break Inside Containment	6 Steam Break Outside Containment	7 Loss of Feedwater Flow	8 Closure of One MSIV	9 Loss of Primary Flow	10 Core Power Increases	11A Turbine Trip	11B Turbine Trip Loss of Offsite Power	11C Turbine Trip Loss of Service Water	12A Reactor Trip	12B Reactor Trip Due to Loss of Component Cooling Water
1) Yankee Rowe	0	0	0	0	0	0	4	0	3	0	8	9	0	46	0
2) Indian Point 1	0	0	1	0	0	0	40	0	7	0	21	3	0	143	0
3) San Onofre	0	0	0	0	0	0	0	0	0	0	8	0	0	11	0
4) Connecticut Yankee	0	0	0	0	0	0	10	2	2	0	16	4	0	32	0
5) R. E. Ginna	0	0	0	0	0	0	14	4	0	0	8	1	0	11	0
6) H. B. Robinson	0	0	0	0	0	0	31	1	2	0	32	1	0	38	0
7) Point Beach 1	0	0	0	1	0	0	2	1	0	0	7	3	0	14	0
8) Point Beach 2	0	0	0	0	0	0	4	0	0	0	7	0	0	11	0
9) Palisades	0	0	0	2	0	0	13	0	1	0	4	0	0	15	0
10) Maine Yankee	0	0	0	0	0	0	4	0	1	1	3	0	0	6	0
11) Surry 1	0	0	1	2	0	0	27	3	2	1	17	2	0	13	0
12) Surry 2	0	0	0	1	0	0	14	7	0	0	10	1	0	6	0
13) Oconee 1	0	0	0	0	0	0	10	0	0	0	18	0	0	10	0
14) Oconee 2	0	0	0	0	0	0	7	0	0	0	7	0	0	4	0
15) Oconee 3	0	0	0	0	0	0	4	0	0	1	13	0	0	3	0
16) Fort Calhoun	0	0	0	0	0	0	3	0	2	0	2	4	0	7	0
17) Kewaunee	0	0	0	0	0	0	11	5	0	0	16	0	0	11	0
18) Arkansas 1	0	0	0	1	0	0	1	0	0	0	4	2	0	10	0
19) Three-Mile Island 1	0	0	0	0	0	0	0	0	0	0	3	0	0	2	0
20) Calvert Cliffs	0	0	0	0	0	0	3	0	1	1	5	0	0	4	0
21) Trojan	0	0	0	0	0	0	5	0	1	0	7	0	0	5	0
22) Millstone 2	0	0	0	0	0	0	6	0	2	0	17	2	0	11	0
23) Zion 1 Plus Zion 2	0	0	1	0	0	0	58	3	5	0	41	0	0	50	0
24) Indian Point 2	0	0	0	0	0	0	35	7	0	0	39	1	0	36	0
25) Indian Point 3	0	0	0	0	0	0	12	0	0	0	8	1	0	8	0
26) D. C. Cook 1	0	0	0	0	0	0	1	0	0	0	3	0	0	3	0
27) Prairie Island 1	0	0	0	0	0	0	10	5	1	0	11	0	0	12	0
28) Prairie Island 2	0	0	0	0	0	0	5	2	1	0	11	0	0	7	0
29) Turkey Point 3	0	0	0	0	0	0	16	1	5	0	18	0	0	23	0
30) Turkey Point 4	0	0	0	0	0	0	14	0	0	0	18	0	0	4	0
Total Number of Events	0	0	3	7	0	0	364	41	36	4	382	34	0	556	0

TABLE 1.5.1-33

INDIAN POINT 2 POPULATION TIME DATA

PWR Plant Name	Operational Years Included in the Data Base
Yankee Rowe	15
Indian Point 1	12
San Onofre	8
Connecticut Yankee	8
R. E. Ginna	6
H. B. Robinson	5
Point Beach 1	5
Point Beach 2	4
Palisades	4
Main Yankee	3
Surry 1	4
Surry 2	4
Oconee 1	4
Oconee 2	2
Oconee 3	3
Fort Calhoun	3
Kewaunee	2
Arkansas 1	2
Three-Mile Island 1	2
Calvert Cliffs	1
Trojan	1
Millstone 2	1
Zion 1 plus Zion 2	11
Indian Point 2	5*
Indian Point 3	3
D. C. Cook 1	1
Prairie Island 1	3
Prairie Island 2	2
Turkey Point 3	4
Turkey Point 4	3

*For turbine trip--loss of offsite power initiating event, 6 years of data were included in the data base.

TABLE 1.5.1-34

INDIAN POINT 2 INITIATING EVENT OCCURRENCE PROBABILITY PER PLANT YEAR

Initiating Event Category	Plant Specific						PWR Population Generic	
	5%	Median	95%	Range Factor	Mean	Variance	Mean	Variance
1	1.06-6	1.16-4	6.30-3	7.71+1	1.95-3	9.26-5	2.59-3	1.75-4
2	1.06-6	1.16-4	6.30-3	7.71+1	1.95-3	9.26-5	2.59-3	1.75-4
3	1.00-4	1.08-2	5.21-2	2.28+1	1.85-2	6.55-4	2.83-2	6.54-3
4	3.73-5	7.39-3	9.50-2	5.05+1	2.74-2	2.31-3	1.38-1	6.49-1
5	1.06-6	1.16-4	6.30-3	7.71+1	1.95-3	9.26-5	2.59-3	1.75-4
6	1.06-6	1.16-4	6.30-3	7.71+1	1.95-3	9.26-5	2.59-3	1.75-4
7	4.84	6.47	8.23	1.30	6.70	1.16	3.16	1.01+1
8	5.30-1	1.14	1.99	1.94	1.25	2.32	4.63-1	9.84-1
9	1.13-2	8.78-2	3.33-1	1.72+1	1.36-1	1.21-2	2.95-1	9.39-2
10	3.23-5	9.23-3	6.82-2	4.60+1	2.21-2	1.38-3	9.36-2	5.13-1
11a	5.35	7.15	9.10	1.30	7.32	1.41	3.91	1.13+1
11b	3.09-2	1.48-1	4.55-1	3.84	2.04-1	2.35-2	2.63-1	9.41-2
11c	1.06-6	1.16-4	6.30-3	7.71+1	1.95-3	9.26-5	2.59-3	1.75-4
12a	4.95	6.58	8.54	1.31	6.84	1.24	4.12	7.47
12b	1.06-6	1.16-4	6.30-3	7.71+1	1.95-3	9.26-5	2.59-3	1.75-4

1.5.1.6 References

1.5.1-1 Hubble, W. H., and C. F. Miller, "Data Summaries of Licensee Event Reports of Value at U.S. Commercial Nuclear Power Plants, January 1, 1976 to December 31, 1978," NUREG/CR-1363, EGG-EA-5125, June 1980.

1.5.1-2 Sullivan, W. H., and J. P. Poloski, "Data Summaries of Licensee Event Reports of Pumps of U.S. Commercial Nuclear Power Plants, January 1, 1972 to April 30, 1978," NUREG/CR-1205, EGG-EA-5044, January 1980.

1.5.1-3 Poloski, J. P., and W. H. Sullivan, "Data Summaries of Licensee Event Reports of Diesel Generators at U.S. Commercial Nuclear Power Plants, January 1, 1976 to December 31, 1978," NUREG/CR-1362, EGG-EA-5092, GM.

1.5.1-4 Southwest Research Institute ANSI Subcommittee, "Nuclear Plant Reliability Data System," 1976 Annual Report of System and Component Reliability, Annual Report (A03), May 1977.

1.5.1-5 U.S. Nuclear Regulatory Commission, "Reactor Safety Study - An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," Appendix III, Failure Data, WASH-1400, October 1975.

1.5.1-6 Nuclear Power Engineering Committee of the IEEE Power Engineering Society, IEEE Guide to the Collection and Presentation of Electrical, Electronic, and Sensing Component Reliability Data for Nuclear Power Generation Stations, IEEE STD-500, 1977.

1.5.1-7 Swain, A. D., and H. E. Guttmann, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," Draft Report, NUREG/CR-1278, October 1980.

1.5.1-8 Nuclear Regulatory Commission, "Operating Units Status Report," NUREG 0020.

1.5.1-9 Electric Power Research Institute, "ATWS: A Reappraisal, Part III. Frequency of Anticipated Transients," EPRI NP-801, July 1978.

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1.5.2 INDIAN POINT UNIT 2 SYSTEM ANALYSES

1.5.2.1 Introduction

1.5.2.1.1 Purpose of System Analyses

1.5.2.1.1.1 Plant Event Tree Requirements. This appendix contains the Indian Point Unit 2 analyses of key systems whose states of operability are inputs to the plant event trees. Early in the study, the key plant systems were identified. Each system was defined by boundary conditions and top events. This allowed the system analysis effort to proceed relatively independently of other major study tasks, such as data analysis and accident sequence development. Analyses of the following systems are provided:

- 1.5.2.2 Electrical, Instrumentation, and Control Systems
  - 1.5.2.2.1 Electric Power System
  - 1.5.2.2.2 Reactor Protection System
  - 1.5.2.2.3 Safeguards Actuation System

- 1.5.2.3 Fluid Systems
  - 1.5.2.3.1 High Pressure Injection System
  - 1.5.2.3.2 Low Pressure Injection System
  - 1.5.2.3.3 Accumulator System
  - 1.5.2.3.4 Recirculation System
  - 1.5.2.3.5 Containment Spray System
  - 1.5.2.3.6 Containment Fan Cooling System
  - 1.5.2.3.7 Component Cooling System
  - 1.5.2.3.8 Service Water System
  - 1.5.2.3.9 Auxiliary Feedwater System

Quantification of failure modes using an Indian Point Unit 2 specialized data base was accomplished as the data became available. In this way, the system analysis efforts provide a large library of quantified performance data. The plant level analysis uses the data and descriptions generated by each system analysis to verify the logic model, quantify state probabilities, identify common mode failures, and identify the dominant contributors. The system analysis is a baseline which is varied as necessary to support each plant event tree condition evaluated in Section 1.3.

1.5.2.1.1.2 System Analysis Results. The results of each system analysis are useful for several purposes. These are listed below:

- Feed data to plant event trees (discussed above).
- Provide an indication of dominant and common cause contributors to system failure.
- Provide insight into design, hardware, and procedural changes which could be made to improve system availability.
- Provide insight into the degree of uncertainty which exists for key results and the origin of data which causes that uncertainty.

1.5.2.1.2 System Description Sources

Plant systems are, for the purpose of this study, adequately described in existing documentation. The primary documents used in the system analyses are listed below. The system analysis process translates the hardware configuration and operating procedures into the system logic model. The interpretations and assumptions necessary to perform these steps are reviewed by plant personnel familiar with the plant configuration and hardware. Adjustments are made to resolve differences as they are discovered. The primary documents used in describing each system are:

- System Descriptions
- Final Safety Analysis Reports
- Test Procedures
- Emergency Operating Procedures
- Drawings, Plant Design
- Electrical Load Lists
- Direct Communications with Plant Staff
- Technical Specifications

1.5.2.1.3 Analysis Procedures

1.5.2.1.3.1 Methodology. The systems analysis methodology base line is presented as part of Section 0, Methodology. This methodology is applied in each analysis according to the needs and preferences of the analyst to address the specific nature of the system being analyzed.

1.5.2.1.3.2 Boundary Conditions and Top Event Definitions. Each system analysis section defines the top event(s), criteria for success, and boundary conditions for analysis. The conditions are often the states of electrical power at specific buses and LOCA conditions. Boundary conditions may also include states of coolant availability, interfacing system availability, or actuation signal availability.

In all cases, statements clearly define the boundary conditions and top events. The selection of these events and conditions is performed early in the study. While these are adjusted from time to time, the compartmentalization of the plant into systems remains valid. This ensures that early efforts to model each system will remain a firm foundation, even though refinements to the analysis may be made.

1.5.2.1.3.3 System Definition. Hardware configuration, operating procedures, and other system information are reviewed in detail. Simplified schematics, P&IDs, block diagrams, and logic tables are prepared to describe the system for modeling purposes.

1.5.2.1.3.4 Simplification Procedures. The system is analyzed to focus attention on its essential characteristics. This involves investigating each component and each interfacing connection to determine if it is to be included in the system model. Techniques are outlined below.

1. Setting Boundary Conditions: Isolation of a defined system boundary simplifies the analysis task on the system level by holding certain interfaces constant, thus defining the states to be analyzed. This

step involves discretization of a large number of possible system states into a small number of broad categories to be analyzed.

2. Simplification of Hardware Configurations: The critical components of each system are identified, and noncritical components are eliminated from the model. The system configuration is simplified by performing a rudimentary failure analysis, i.e., asking the question: "If this component failed, could it prevent the performance of a critical function?" In this way, test and instrumentation lines and circuits are often removed from further consideration. Also, components which support noncritical functions outside the boundaries of the system are not analyzed in detail. The P&IDs, schematics, and logic diagrams presented in the system analysis sections identify and define the simplified versions of the actual systems.

3. Use of Conventional Analysis Techniques to Show Nondominance: If the unavailability or unreliability data associated with an event indicates it is infrequent by many orders of magnitude, compared with other expected events, it may be eliminated from further consideration. This is accomplished as the simplified system description is prepared. For example, fluid systems are sometimes isolated through two check valves installed in series. This may justify eliminating down stream components at the time the simplified P&ID is prepared.

Simplification of this type accompanies the quantification steps. A component event (failure mode) with an unavailability of less than say, 10^{-6}, combined with the knowledge that there are a limited number of components of this kind, effectively eliminates it from importance in the analysis. Similarly, components with higher failure probabilities, but which require a combination of occurrences to have system consequences, are carefully eliminated from further analysis. In this respect, fault tree models and minimum cutset analyses are extremely useful. Fourth order cutsets are generally eliminated by a scan of the failure rates. Third order cutsets are usually eliminated--except in special cases involving combinations of very high probability events. Single and double order cutsets are evaluated independently to ascertain their significance. The analytical methodology is adjusted throughout this process to reflect the importance placed on the anticipated result in terms of its dominance as a contributor to an event tree level event. Usually, conventional availability and reliability probability calculations are judged to be sufficient when showing that intermediate events (i.e., those that may contribute to a system level top event) are, in fact, of such low probability to be insignificant in subsequent calculations.

1.5.2.1.3.5 System Analysis Development. Each system has individual characteristics which govern the analyst's approach. Less complex systems may address from one to four events relating to the plant event tree. More complex systems may have up to 30 event conditions which need to be analyzed. This may require intermediate divisions to structure the system analyses into manageable form. The smaller systems can

be simplified for analysis purposes by gathering components into groups which have equivalent system effects. This may result in a series of "supercomponents" which can be represented on a simplified reliability block diagram. By observing the series and parallel configurations of the blocks, one can easily determine the single order failures, double cutsets, maintenance conditions, etc. The analysis can proceed by considering each block as a component.

Systems are judged to be more complex by virtue of their component population, their logic and configuration, and the number of states in which they can fail. If there are a number of states, as determined by tree events, boundary conditions, and other conditions such as electric power availability, the hardware configuration must be divided into component configurations relevant to each state. In this case, the analyst proceeds by performing a systematic failure mode evaluation. Each component failure mode is tested to see which system states are affected, and each system failure mode is examined to see which components are needed. The procedure is repeated for double cutsets and reviewed for higher order evaluations. The resulting groups of components may not be identified as supercomponents and may not be easily structured into a block diagram. Nevertheless, they form the basis for the system failure quantification. They can also be modified to analyze maintenance and test states, etc. This approach results in an analysis methodology which builds upon previous results. That is, once a key mode is analyzed, other modes become slight variations of it, or expansions of the original component group. This is logical, and forms a basis for expediting the analysis and shortening the description of the quantification process.

1.5.2.1.3.6 Fault Tree Development and Cutset Generation. The above procedures allow the system analysis to proceed largely without the aid of computer aided fault tree reduction. Nevertheless, fault trees are useful to discipline the analysis, to display the logic, and to verify that significant failure modes are not overlooked. Most of the system analysis sections include fault trees and cutset identifications. The degree to which the analyst relied on these tools is evident in the system presentations.

1.5.2.1.3.7 DPD Codes. A computer code for performing Discrete Probability Distribution (DPD) arithmetic is available and was used wherever the system analysis indicates this technique was applied. DPD is used at the point in the calculations where the significant results are calculated and it is desired to carry the parametric variations introduced by uncertainty and discrete distribution expressions more precisely.

1.5.2.1.4 Guidelines to Presentations

1.5.2.1.4.1 Results. Results are summarized in the beginning of each system analysis. The major contributors are indicated. In general, means are presented for use in the plant level studies.

1.5.2.1.4.2 System Schematics and Block Diagrams. System schematics and block diagrams are included in the system description sections. These are based on the general references provided in Section 1.5.2.1.2 and specific references provided within the section and on the diagrams.

1.5.2.1.4.3 Cause Tables. Cause tables are included for each system. The list of possible causes includes random hardware failures, testing, maintenance, human error, common cause and other. Unless insignificant, or not applicable, the unavailability contribution is presented for each cause. The effects on components, systems, other systems, and initiating events are shown.

1.5.2.1.4.4 Component (and Event) Data. Each system analysis section includes a list of components by generic name, code name, and failure mode. The data table for each system analysis presents the mean and variance for failure rate or unavailability. Where applicable, time to repair estimates and reliability failure rates are presented. The data is referenced to the data tables in Section 1.5.1 by item number. Where the data source is unique, it is also referenced in the component data table.

1.5.2.1.4.5 Pipe Failure Analysis Tables. Each fluid system includes a failure mode and effect table for piping failures. The system effect of ruptures and leaks and the probability of the occurrence are presented for input to the analysis.

1.5.2.1.4.6 Minimum Cutset Tables. Minimum cutset tables have been generated in most cases, but only significant results have been summarized in the text.

1.5.2.1.4.7 Fault Trees. Fault trees are included in every system analysis. Because of the number of pages, they are placed at the end of each system analysis section. The methodology and symbol codes for fault trees are described in Section 0, Methodology. The coding for the fault tree events is also defined in Section 0.

1.5.2.1.4.8 Calculation. Calculations are integrated with the text, or presented in tabular form and placed at the end of the text in each system analysis. Only general references to the analytical methodology are presented. In most cases calculations can be followed by the equations provided, combined with following the numerical trail of the calculation.

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1.5.2.2. Electrical, Instrumentation, and Control Systems

1.5.2.2.1 Indian Point 2 Electric Power System

1.5.2.2.1.1 Summary.

1.5.2.2.1.1.1 Introduction. The Indian Point Unit 2 electric power system provides a source of motive, control, and instrumentation power to those components of the plant safeguards systems whose operation is needed to mitigate any abnormal event affecting the reactor core, its heat removal systems, or systems which could result in the release of radioactivity to the environment. This function is normally accomplished by a reliable offsite power supply network with a fully redundant onsite emergency generation capacity that is available in the event all offsite power sources are lost.

To illustrate the interfaces between this system and the plant safeguards systems components, and to fully develop the interrelationships among the various electrical subsystems, the electric power system is modeled in detail to the level of individual motor control centers and power distribution panels. However, the system failure quantification is limited to a determination of the power unavailability at the four 480V essential switchgear buses.

Except for the diesel generator fuel oil transfer pump power supplies, the Indian Point Unit 2 electric power system is analyzed as presently installed. Consolidated Edison recently decided to modify the supplies to these pumps, and this modification has been incorporated into the analysis. Operating, testing, and maintenance procedures and practices that affect the electric power system are considered as they are currently implemented at the station.

Because all initiating events in this study result in a trip of the main generator, power supply to the electric power system from this source is not included in this analysis. Offsite power is defined in this study as the 345 kV and 138 kV normal offsite power sources to Unit 2. Manual operator actions for the recovery of any power source are excluded from this analysis. Therefore, the status of the offsite power supply does not define the status of either the 13.8 kV offsite power supply from Buchanan substation or the three gas turbine-generating units available to the site. Loss of offsite power defines the specific condition in which no power is available to Unit 2 from sources other than the onsite diesel generators, if no manual operator actions are taken for alternate supply recovery. Failures of the station auxiliary transformer are included in the analysis of onsite electric power system failures.

Because many of the event categories considered in this study may be mitigated with less than the design basis power supply capabilities, the electric power system is analyzed for the 16 operability states summarized in Table 1.5.2.2.1-1. Each of these states is developed further for the two following boundary conditions:

1. Offsite power not available.
2. Offsite power available.

The system failure analysis is extended to 6 hours following the initiation of any of the event sequences considered in this study. No operator actions for the recovery of failed equipment are considered. Although this is an extremely pessimistic evaluation of operator response, this approach ensures that the results of this analysis provide conservatively bounding values which are applicable to all the initiating event sequences studied. These recovery factors must be included in any complete evaluation of the contribution of electric power system failures to overall public risk. However, the impact of power recovery and the probability of successful operator response are highly dependent on the precise scenario during which the failures occur. Therefore, recovery actions are not quantified in this system analysis and are applied only in the context of those event sequences in which the failures of electric power are significant contributors to risk.

The system is considered to be in its normal configuration according to plant operating procedures with all buses energized from their normal power sources immediately before event initiation.

1.5.2.2.1.1.2 Results. Tables 1.5.2.2.1-2A and 1.5.2.2.1-2B summarize the quantification of the 16 mutually exclusive electric power system operability states for each of the analysis boundary conditions. (The mutually exclusive state "Failure of Power at Buses 2A and 5A" is defined by the conditions: no power at bus 2A, no power at bus 5A, and power is available at buses 3A and 6A.) The mutually exclusive failure frequencies have been developed from the unconditional power failure states by applying basic Boolean logic, as described in the main body of this study. These results do not include the effects of operator actions to recover failed equipment during the 6-hour period following event initiation. This approach is very conservative because inclusion of these recoverability factors would significantly reduce the unavailability of power in several of the states analyzed.

The loss of offsite power is a unique initiating event from the standpoint of electric power system operation. Table 1.5.2.2.1-2C summarizes the operability state frequencies which are applicable to the event sequences developed for this initiator.

All initiating events analyzed in this study result in a trip of the main generator. For transients other than those initiated by the loss of offsite power, it is possible that transmission network perturbations produced by this sudden loss of generation could cause a loss of offsite power due to the Indian Point Unit trip. A conservatively bounding distribution with a median value of 1.97×10^{-5} failures per unit trip has been assigned to this conditional event. The operability state frequencies summarized in Table 1.5.2.2.1-2D are composite probability distributions applicable to all initiating events other than the loss of offsite power. These states were obtained by combining the distributions in Tables 1.5.2.2.1-2A and 1.5.2.2.1-2B with the conditional probability distribution for the loss of offsite power as the result of a unit trip.

No direct comparison can be made between these results and those developed for electric power system unavailability in the Reactor Safety Study (RSS). This comparison cannot be made because:

- The physical configuration and the operation of the Indian Point Unit 2 electric power system are significantly different from those of either the pressurized water reactor (PWR) plant or the boiling water reactor (BWR) plant electric power systems analyzed in the RSS.

- The analysis methodology applied in this study, while conceptually similar to the basic approach adopted in the RSS, explicitly quantifies each possible system operability state under two offsite power boundary conditions and for a broad range of events in addition to the loss of coolant accident (LOCA) initiators.

- The site specific nature of this study has a significant impact on the dominant contributors to electric power unavailability identified for the two plants analyzed in the RSS.

1.5.2.2.1.1.3 Conclusions. The Indian Point Unit 2 electric power system has been analyzed for 16 independent operability states under two global offsite power boundary conditions. These states and boundary conditions have been combined to provide conservatively bounding distributions for the unavailability of electric power, which are applied to each of the initiating event scenarios investigated in this study. The dominant contributors to the failure of electric power for a given operability state depend on the precise system configuration and boundary conditions applicable to that specific state. However, a few general observations may be made about the results.

The more restrictive of the two boundary conditions is that in which offsite power remains unavailable for the entire 6-hour analysis period. The mean frequency of occurrence of the dominant electric power system operability states are:

- All four 480V switchgear buses remain energized: 85.9%.
- One 480V switchgear bus is deenergized: 9.1%.
- Two 480V switchgear buses are deenergized: 4.7%.

The unavailability of power for each of the system states analyzed under this boundary condition is dominated by failure of the power supply from the diesel generators. The unavailability of power from a diesel generator is attributable to three principal causes:

1. Unavailability of the diesel generator due to maintenance: 62% of diesel generator unavailability.

2. Failure of the diesel generator to start on demand: 27% of diesel generator unavailability.

3. Failure of the diesel generator during operation for 6 hours: 11% of diesel generator unavailability.

If a unit trip occurs and offsite power remains available to the station auxiliary transformer, the mean frequency of occurrence of the dominant electric power system operability states is:

- All four 480V switchgear buses remain energized: > 99.99%.
- One 480V switchgear bus is deenergized: 0.01%.

The failure of power at bus 2A or bus 3A is dominated by the failure of breaker UT2/ST5 or UT3/ST6 to close following a unit trip. Because diesel generator 22 will not automatically reenergize either of these buses if normal power remains available to buses 5A and 6A, these single breaker failures will cause these buses to remain deenergized if no operator recovery actions are taken. The automatic diesel generator loading logic is a significant contributor to each of the other failure states. This logic trips the normal power supply breakers to all four of the 480V buses if an undervoltage condition is detected at either bus 5A or bus 6A following a unit trip. The diesel generators are automatically started and loaded onto all four buses by this signal, and subsequent diesel generator failures result in the loss of power at the associated buses.

It cannot be emphasized too strongly that the results of this analysis have been developed as very conservative bounding values to be applied to a broad spectrum of initiating event sequences. The exclusion of system recovery factors and the analysis of system failures over a nominal 6-hour operating period lead to extreme conservatism in many of these results. The results of this analysis are, therefore, directly applicable only to the identification of those specific event sequences that contribute significantly to public risk. Once these sequences have been identified using these bounding analysis failure states, specific recovery actions will be defined and quantified in the context of entire plant recovery.

1.5.2.2.1.2 System Description.

1.5.2.2.1.2.1 System Function. In the context of this study, the primary functions of the electric power system are:

- Provide a reliable source of motive power to those components whose operation is needed to mitigate any abnormal event affecting the reactor core, its heat removal systems, or systems which could affect the release of radioactivity to the environment.

- Provide a reliable source of control power for the operation of these systems and for the initiation of safeguards systems actuation signals.

- Provide a reliable source of power to instrumentation necessary for monitoring emergency system functions, for monitoring key plant parameters, and for inputs to safeguards systems actuation logic matrices.

A reliable offsite power supply network connected to the station power system through redundant supply paths normally performs these functions. In addition, one onsite gas turbine unit and two gas turbines located at the adjacent Buchanan substation may be connected to the station power system through the offsite power supply tielines. This provides additional redundancy of offsite power supply capabilities. If these offsite power sources all fail, three redundant diesel generators, each capable of supplying 50% of the power requirements of the safeguards systems components, provide independent onsite power generation capabilities. A DC power system, supplied from four onsite storage batteries, provides redundant power to vital controls and instrumentation, and is the primary source of power to all safeguards actuation and reactor protection system circuits.

The extensive use of manual crosstie interconnections within each of these systems allows plant personnel to selectively energize subsystems and specific components in the event of multiple redundant power supply failures. Indian Point Unit 2 also has an independent alternate shutdown power supply system which provides a source of power from the Unit 1 station auxiliary electric power system to one charging pump, one auxiliary feedwater pump, one service water pump and one motor control center. The transfer to this alternate power supply source is accomplished via a manual disconnect switch for the auxiliary feedwater pump (located near the pump) and via manual routing and termination of contingency power cables to the charging and service water pumps and the motor control center.

A simplified block diagram of the 480V essential power buses is shown in Figure 1.5.2.2.1-1. The normal and reserve sources of DC control power for the circuit breakers and major components supplied from these buses are illustrated in the block diagram of Figure 1.5.2.2.1-2.

1.5.2.2.1.2.2 System Operation. Figure 1.5.2.2.1-3 is a one-line diagram of the complete Indian Point Unit 2 electric power system. During normal operation, power is supplied to 6.9 kV buses 1, 2, 3, and 4 from the main generator output through the unit auxiliary transformer. Power is supplied to 6.9 kV buses 5 and 6 from the offsite power grid through the 138 kV substation and station auxiliary transformer. Following a trip of the main generator, automatic crosstie breakers connect buses 1 and 2 to bus 5 and connect buses 3 and 4 to bus 6, thereby maintaining all six 6.9 kV buses powered from the offsite grid. The redundant source of offsite power from the 13.8 kV substation and gas turbine Unit 1 may be manually connected to buses 5 and 6 only if these buses are deenergized and their normal supply breakers from the station auxiliary transformer are open. Although no essential safeguards components are supplied directly from the 6.9 kV buses, buses 2, 3, 5, and 6 supply power to the 480V essential power buses 2A, 3A, 5A, and 6A through their respective station service transformers.

1.5.2.2.1.2.2.1 Offsite power supply and gas turbine units subsystems. Power produced by the Unit 2 main generator is stepped up in voltage from the 22 kV generator output to 345 kV through parallel main transformers 21 and 22. This 345 kV power is then transmitted by overhead towers (one section of which also carries the 138 kV power supply to the station auxiliary transformer) to the 345 kV substation at Buchanan. From the Buchanan ring bus, power is transmitted on two 345 kV feeders to Sprainbrook, Pennsylvania, New Jersey, and Maryland.

As shown in Figure 1.5.2.2.1-3, the Unit 2 station auxiliary transformer receives power from the Consolidated Edison system through a 138 kV switching station located next to the Unit 1 turbine building. This switching station also supplies 138 kV power to the Unit 3 station auxiliary transformer. Two 138 kV overhead transmission lines tie the switching station to the Buchanan 138 kV substation, which has connections to the Consolidated Edison Millwood Switching Station and the Lovett Station of the Orange and Rockland System. Bus tie breakers BT4-5 and BT5-6 at the 138 kV switching station are normally closed. This arrangement allows Buchanan feeders 95331 and 95332 to supply power to both the Unit 2 and the Unit 3 station auxiliaries without any manual switching operations. These bus tie breakers are operated from the Unit 1 control panels.

Two separate underground feeders (13W92 and 13W93) from the Buchanan 13.8 kV substation are also available to provide a redundant source of offsite power to both Units 2 and 3 through interconnections at the Unit 1 gas turbine installation and at the onsite 13.8 kV substation located between Unit 1 and Unit 3. To connect the Unit 2 6.9 kV buses 5 and 6 to either of these 13.8 kV power supplies, the buses must first be deenergized and the normal feed breakers from the Unit 2 station auxiliary transformer (ST5 and ST6) must be open.

A gas turbine is located onsite and may be connected to either Unit 2 or Unit 3 through the 13.8 kV switchgear located at the gas turbine installation at Unit 1. During normal plant operation, breaker GT/BT is

open and breaker GT/2F is closed. This breaker alignment maintains the Unit 1 gas turbine and 13.8 kV feeder 13W92 available for service to Unit 2 through breakers GT-25 and GT-26. The gas turbine is started and operated from the Unit 1 control panels. (The control panels for Unit 1 and 2 share a common control room.) Two additional gas turbines are located at the Buchanan substation and may be connected to either Unit 2 or Unit 3 through the 138 kV or 13.8 kV tielines. Gas turbine Unit 2 at Buchanan is normally aligned for service to Indian Point Unit 3 through 13.8 kV feeder 13W93. The third gas turbine may be aligned to either of the Indian Point units. Remote starting capability for these gas turbines is available in the Unit 1/Unit 2 control room. Breakers GT-1, GT-2, GT-25, and GT-26 are operated from the Unit 1 control panels. Breakers GT/2F and GT/BT are operated from the Unit 3 control room.

1.5.2.2.1.2.2.2 480V essential power supply subsystem.

1.5.2.2.1.2.2.2.1 Station auxiliary transformer. The normal source of offsite power to Unit 2 from the Buchanan 138 kV substation is stepped down to 6.9 kV through the station auxiliary transformer, which is connected to 6.9 kV buses 5 and 6 through supply breakers ST5 and ST6, respectively. The transformer is rated at 48,160 kVA and is oil-filled with a 5 to 10 psig nitrogen cover pressure and forced air oil coolers.

The protective relays for the station auxiliary transformer are activated by the following conditions:

- Transformer differential current.
- Transformer overcurrent.
- Transformer neutral ground overcurrent.
- Failure of breaker ST5 or ST6 to clear a fault at 6.9 kV bus 5 or 6.
- Failure of breaker BT4-5 to clear a fault at the 138 kV switchyard.
- Transfer trip signal from the pilot wire protection relays for Buchanan 138 kV feeder 95332.

When activated, the transformer protective relays trip and lock out 6.9 kV breakers ST5 and ST6, trip 138 kV breaker BT4-5, trip the pilot wire relays for feeder 95332, and provide trip annunciation in the Unit 2 control room.

1.5.2.2.1.2.2.2.2 Gas turbine/13.8 kV substation supply. A redundant source of offsite power from the 13.8 kV substation and an independent power supply from the onsite Unit 1 gas turbine installation are available to 6.9 kV buses 5 and 6 through supply breakers GT-25 and GT-26. These breakers are interlocked with the normal supply breakers ST5 and ST6 to prevent both breakers for a given bus from being closed at the same time. The transfer from the normal to the reserve supply (or vice versa) must be done manually and is a "dead bus"

transfer (i.e., the normal supply breaker must be opened before the reserve breaker is closed). The controls for breakers GT-25 and GT-26 are located at the Unit 1 control panels. Breaker position indication is provided on the Unit 2 control panels in the common Unit 1/Unit 2 control room.

Gas turbines 2 and 3 are located at the Buchanan substation and may be started remotely from the Unit 2 control room. Either of these gas turbines can supply power to the Unit 2 electric power system through the Buchanan 138 kV tielines (feeders 95332 and 95331) or through the 13.8 kV connections (feeders 13W92 and 13W93).

During normal plant operation, breaker GT/BT is open and breaker GT/2F is closed. This breaker alignment maintains gas turbine 1 and 13.8 kV feeder 13W92 available for service to Unit 2. Buchanan gas turbine 2 and feeder 13W93 are normally available for service to Indian Point Unit 3.

1.5.2.2.1.2.2.2.3 6.9 kV system. The six station 6.9 kV buses provide power to auxiliary equipment rated at 400 horsepower and above, and do not directly supply any safety related system components. During power operation, buses 1, 2, 3, and 4 are normally supplied from the Unit 2 main generator through the unit auxiliary transformer. Actuation of the main generator trip relays results in an automatic "dead fast transfer" of the supply to these buses to the station auxiliary transformer through the crosstie breakers connecting buses 1 and 2 to bus 5, and buses 3 and 4 to bus 6 (refer to Figure 1.5.2.2.1-3). This relaying scheme provides a transfer which is rapid enough to prevent voltage and current supply fluctuations from affecting any of the equipment powered from these four buses. Buses 5 and 6 are normally supplied from the station auxiliary transformer, and are not affected by the operating status of the main generator. An overcurrent condition on any of the 6.9 kV buses actuates the associated bus protection lockout relays, which isolate the bus by tripping and locking out the normal supply breaker and the 6.9 kV tie breaker for that bus.

Buses 2, 3, 5, and 6 supply the normal power to 480V essential power buses 2A, 3A, 5A, and 6A through individual station service transformers. These are dry type transformers, each rated at 2,666 kVA and are designed for natural convection cooling. Automatic fans are provided for supplementary cooling if the natural air circulation is not sufficient. The supply breakers from the 6.9 kV buses to the individual station service transformers trip automatically on either an overcurrent condition at the associated transformer or an undervoltage condition at the supply bus. If tripped, these breakers must be closed manually from the Unit 2 control panels.

The 6.9 kV buses are housed in two metal enclosed switchgear units located at Elevation 15' of the Unit 2 turbine building. Buses 1, 2, and 5 are contained in switchgear enclosure 21; buses 3, 4, and 6 constitute switchgear enclosure 22. DC control power for operating the circuit breakers associated with buses 1, 2, and 5 is supplied from

125 VDC power panel 21. Control power to the breakers at buses 3, 4, and 6 is supplied from 125 VDC power panel 22.

1.5.2.2.1.2.2.2.4 480V essential power buses. Components rated between 100 and 400 horsepower are supplied directly from the station 480V buses 2A, 3A, 5A, and 6A. Individual loads of 100 horsepower and below are supplied from 480V motor control centers (MCCs) fed from the 480V buses. The normal power supply to each of the 480V buses is from its associated 6.9 kV bus through a station service transformer. If this normal power source is unavailable, an independent source of onsite power is provided to each of these buses from the three emergency diesel generator units. (As illustrated in Figure 1.5.2.2.1-3, diesel generator 21 supplies bus 5A, diesel generator 23 supplies bus 6A, and diesel generator 22 supplies buses 2A and 3A through individual feed breakers.)

The station safeguards systems components are distributed among the four 480V buses in such a manner that, with coincident loss of all offsite power sources and failure of any one of the diesel generators, power will remain available to the minimum number of components needed to mitigate any of the design basis accident scenarios evaluated in the Indian Point Unit 2 final safety analysis report. (Under many situations that are less restrictive than these limiting design basis events, the accident may be mitigated by less than this nominal power supply availability.) The loads supplied from each of the 480V buses are summarized in Table 1.5.2.2.1-3.

If a fault occurs on one of the 480V buses, lockout relays are actuated. These relays trip and prevent reclosure of all breakers associated with the bus, including feeds from the station service transformer, diesel generator, and 480V bus tie breakers. These relays must be manually reset after the fault is cleared to allow any breaker to be reclosed.

The normal feed breaker to each bus from the station service transformer may be operated from either the Unit 2 control panels or from a local panel in the diesel generator building. The breaker may be closed from the main control room only if the associated bus is deenergized. The breaker may be closed from the diesel generator panel with the bus energized, using the local synchronizing scope interlock, to allow paralleling of the diesel generator and normal supplies during testing and other transfer operations. The normal feed breakers trip automatically on any of the following conditions:

- Bus lockout relay actuation.
- Safety injection with undervoltage on bus 5A or 6A.
- Main generator trip with undervoltage on bus 5A or 6A.
- Overcurrent.

The supply breaker from a diesel generator to its associated 480V bus cannot be closed unless all of the following conditions exist:

- No fault on the 480V bus.
- Normal diesel generator output voltage.
- Synchronizing scope on or an undervoltage condition existing on the 480V bus.

The breakers can be closed manually from either the Unit 2 control panels or from local control switches at the associated diesel generator control panels in the diesel generator building. The breakers will close automatically if the conditions listed in the preceding are satisfied on each associated bus and either of the following conditions are detected:

- Safety injection with undervoltage on bus 5A or 6A.
- Main generator trip with undervoltage on bus 5A or 6A.

The diesel generator feed breaker to a 480V bus trips automatically on any of the following conditions:

- Bus lockout relay actuation.
- Low diesel generator output voltage.
- Trip of the associated diesel generator.
- Overcurrent.

In addition to the normal and emergency power supplies to each of the 480V buses, crosstie breakers between buses 2A and 5A, 2A and 3A, and 3A and 6A provide manual interconnection for these buses (refer to Figure 1.5.2.2.1-3). These breakers are administratively controlled to remain open during normal unit operation and may be closed from the control room only if no fault exists on either of the associated buses and if one of the buses is deenergized. These breakers trip automatically on any of the following conditions:

- Bus lockout relay actuation on either associated bus.
- Undervoltage on both associated buses.
- Safety injection signal.
- Overcurrent.

Three loss of power conditions are particularly important to the 480V power supply system. These conditions are:

1. Safety Injection With No Blackout: defined as any safety injection signal during which both buses 5A and 6A remain energized, indicating normal offsite power is available.

2. Safety Injection With Blackout: defined by a coincident safety injection signal with undervoltage at either bus 5A or 6A, indicating probable loss of offsite power.

3. Blackout With No Safety Injection: defined by a coincident trip of the main generator with undervoltage at bus 5A or 6A, indicating probable loss of offsite power.

Following a safety injection with no blackout, all equipment supply breakers from the 480V buses are tripped, except the feeds to MCCs 26A, 26B, 24, 29, and 211. All three diesel generators start and run at idle, but their associated supply breakers remain open. (If either bus 2A or 3A is deenergized in this condition, its associated diesel generator supply breaker must be manually closed from the control room.) Safeguards systems components are then automatically reenergized sequentially through a series of time delay bus loading relays (nonessential equipment remains stripped until manually reenergized). Following a safety injection with blackout, the normal feed breaker to each 480V bus is tripped, and all equipment supply breakers are tripped, except the feeds to MCCs 26A and 26B. All three diesel generators start, and their supply breakers close automatically to reenergize all four buses. The safeguards system components are then sequentially reenergized (in a slightly different sequence from that in the case of no blackout) to minimize the loading transient on the diesel generators. A blackout with no safety injection similarly causes the normal 480V bus feed breakers to trip and all equipment to be stripped, except MCCs 26A and 26B. The diesel generators start and reenergize all four buses, and components are sequentially reclosed onto the buses to minimize the resulting loading transient. However, because there is no coincident safety injection in this case, the automatic loading sequence assigns a higher priority to the components needed for normal unit trip recovery (e.g., auxiliary feedwater pumps, service water pumps, component cooling pumps, fan cooler units) than it does for the core injection components reenergized first during the two safety injection scenarios.

The 480V buses are housed in two metal enclosed switchgear units located at Elevation 15' of the Unit 2 control building. Buses 5A and 2A are contained in switchgear enclosure 21; buses 6A and 3A constitute switchgear enclosure 22. The DC control power supplies for the circuit breakers at each of these buses and for each of the diesel generators are shown in the block diagram of Figure 1.5.2.2.1-2. A DC voltage sensing relay is located at each 480V bus and at each diesel generator to provide automatic transfer to the reserve control power supply if the normal supply should be deenergized.

1.5.2.2.1.2.2.2.5 Diesel generators. Each of the emergency diesel generators is powered by a 16-cylinder, four-cycle, turbo-charged diesel engine rated at 2,450 horsepower and 900 rpm. The generator driven by this engine is a self-excited, three-phase, 60 hertz, 480V unit rated at 2,188 kVA at 0.8 power factor. The output ratings of each diesel generator unit are 1,750 kW for continuous service and 1,950 kW for a maximum of 2,000 hours. Each unit is capable of supplying sufficient power to maintain the operation of at least 50% of the safeguards systems components required for mitigating any of the design basis accident scenarios analyzed in the Indian Point Unit 2 final safety analysis report.

All three diesel generators receive an automatic starting signal under either of the following conditions:

- Undervoltage on any 480V bus.
- Safety injection signal.

However, for a diesel generator to be available for auto starting, the engine starting mode control switch located at the diesel generator control panel in the diesel generator building must be in the "Auto" position. (Two other positions are available: "Off," which prevents the engine from starting, and "Manual," which allows manual starting from the local panel start pushbutton only.) An alarm is received in the control room if the switch is removed from the "Auto" position. Each diesel generator can attain full speed and voltage within 10 seconds and can be fully loaded within 30 seconds from the time of the starting signal. A speed droop fast acting electro-hydraulic governor maintains a constant diesel engine speed as load is applied to the unit. The generator output breakers will close automatically to load the diesel generators onto their associated buses only under the following conditions:

- Safety injection with blackout.
- Blackout with no safety injection (coincident with a main generator trip).

A more detailed description of these conditions and a discussion of the associated bus load sequencing schemes and the controls and interlocks provided for the diesel generator output breakers are presented in Section 1.5.2.2.1.2.2.2.4.

The normal protective function trip signals provided for each diesel generator are:

1. Local emergency stop pushbutton.
2. Generator overcurrent.
3. Generator reverse power.
4. Diesel engine overcrank (failure to attain speed within 37 seconds after start signal).
5. Low lube oil pressure.
6. Diesel engine electrical overspeed trip relay.
7. Diesel engine mechanical overspeed trip.

An automatic start due to a safety injection signal causes the first three of these trips to be blocked. These trips are automatically reinstated following clearance of the safety injection signal. Following any trip of the diesel generator, the trip lockout relay must be manually reset at the local diesel generator control panel before the engine can be restarted.

For successful starting and continued operation of the diesel generators, four auxiliary systems must be available: the diesel engine

starting air system, the diesel fuel oil transfer system, the station service water system, and 125 VDC control power. Each diesel engine has a 53 ft^3 starting air receiver, which is normally maintained at a pressure of 30 psig by a starting air compressor. The power supplies for these compressors are listed in Table 1.5.2.2.1-4. When fully charged, the receiver volume is sufficient to provide air pressure for three or four normal diesel engine starts without recharging. Although normally isolated, an equalizing line is available to connect all three receivers, in the event of failure of any of the air compressors. Each receiver discharges to two engine starting air motors through separate discharge lines and pressure reduction valves. DC solenoid-operated starting air valves are located in each line to admit air pressure to the starting motors. Either of the two starting motors will provide sufficient torque to start the diesel engine rolling.

Each diesel engine has a 175-gallon fuel oil day tank, which serves as an immediate source of fuel for engine starting and short term operation. (The diesel generator consumes approximately 115 gallons of fuel oil during 55 minutes of full load operation.) Fuel flows by gravity from the day tank to a booster pump driven from the free end of the diesel engine crankshaft and then to the individual cylinder fuel injection pumps. The primary storage capacity for the diesel generator fuel is provided by three 7,700 gallon underground fuel tanks located on the east side of the diesel generator building. When full, the three tanks contain enough fuel for approximately 72 hours of continuous operation of all three diesel generators at full load. The tanks are filled through a common truck hose connection and fill header. A fuel oil transfer pump is mounted on each tank and can be aligned to discharge through the common normal or emergency makeup line to all three diesel generator fuel oil day tanks. The pump power supplies are listed in Table 1.5.2.2.1-4. If a low level is detected in the day tank for diesel generator 21, transfer pump 21 will automatically start to refill the tank to approximately 158 gallons. If pump 21 fails to refill the day tank, transfer pump 23 will receive an automatic starting signal as a backup to the primary pump. Transfer pump 22 receives an automatic starting signal on low level in the day tank for diesel generator 22 and is backed up by transfer pump 21. Transfer pump 23 starts on low level in the day tank for diesel generator 23 and is backed up by transfer pump 22. A summary of the automatic transfer pump starting logic is included in Table 1.5.2.2.1-5.

The station service water system provides cooling water for the diesel engine jacket water cooling system heat exchangers and for the engine lube oil coolers. Two service water supply lines to each diesel generator are available: one from the service water nuclear services header, and one from the conventional services header. During normal plant operation, the diesel generators are aligned to the nuclear services header. A more detailed discussion of the plant's service water supply system is contained in the service water system analysis section of this study.

The diesel generators use 125 VDC control power for several auxiliary functions during starting and loading. To admit air pressure from the

starting air receiver to the engine starting motors, the DC solenoid operated starting air valves must be energized from the engine starting control circuitry. If DC power is not available to these valves, they may be opened manually by a mechanical pushbutton mounted on the valve body. This admits air to the starting motors and allows the engine to start rolling. DC power also provides automatic field flashing for the generator exciter before transferal to self-excitation from the generator output. Under normal circumstances, sufficient residual magnetism may be available within the exciter to provide an initial field for the generator. However, this residual field strength depends on factors such as the hysteresis characteristics of the generator rotor and the time since the generator was last operated. In addition, DC control power is required for automatic or remote closure of the generator output breakers. If DC power is unavailable, these breakers may be closed manually only at the 480V switchgear by a removable handle. Once started and loaded, a diesel generator does not need DC power for continued operation. Starting and operation of the emergency diesel generators may be feasible without DC control power. However, the lack of personnel experience in performing the required operations and the lack of specific station procedures for these operations indicate that the likelihood of successful diesel generator operation under these conditions within a relatively short time period (e.g., 1 hour or less) is small. As discussed in Section 1.5.2.2.1.2.2.2.4, Indian Point Unit 2 has two redundant sources of DC control power for each diesel generator. These supplies are shown in Figure 1.5.2.2.1-2 and are summarized in Table 1.5.2.2.1-4.

The diesel generators, fuel oil day tanks, starting air compressors and receivers, and local control panels are all located in the diesel generator building on the south side of the Unit 2 primary auxiliary building. The fuel oil transfer pumps and the fill connection for the underground storage tanks are housed in a structure built over the storage tanks directly to the east of the diesel generator building.

The Indian Point Unit 2 technical specifications require that a minumum of 41,000 gallons of fuel oil for the diesel generators be available onsite at all times. The additional storage capacity for this fuel, beyond the 23,100 gallons available in the three underground tanks, is provided by the two Unit 1 gas turbine fuel oil storage tanks and the oil storage tank at Buchanan substation.

1.5.2.2.1.2.2.3 DC power subsystem. The Indian Point Unit 2 DC power system consists of four independent battery installations. Each is connected to a DC power panel and is maintained under continuous charge by a self-regulating battery charger. The system is ungrounded, with the positive and negative legs maintained at a potential of approximately 125 volts with respect to ground. Ground detection is provided for each battery division with alarms in the control room.

Power panels 21 and 22 provide the primary sources of DC power to the safeguards equipment in Unit 2. The major loads supplied by each of these panels are listed in Table 1.5.2.2.1-6. A bus tie breaker is

available to connect power panel 21 to power panel 22 in the event of failure of the battery or battery charger for either of the panels. This breaker is administratively controlled to remain open during normal operation to maintain the separation and independence of these DC power divisions. Batteries 23 and 24 provide independent sources of DC power for operating the static inverters that supply 118 VAC instrument buses 23 and 24. These batteries are also used as reserve sources of DC control power for the operating the 480V switchgear and diesel generators as described in Sections 1.5.2.2.1.2.2.2.4 and 1.5.2.2.1.2.2.2.5.

Battery installations 21, 23 and 24 are each composed of 60 individual lead antimony cells that are connected to provide a nominal float voltage of 130.2 VDC. The battery 22 installation is composed of 58 lead calcium cells that are connected to provide a nominal float voltage of 130.5 VDC. Battery 21 is rated at 1,320 ampere hours, and battery 22 is rated at 1,200 ampere hours (both at an 8-hour discharge rate). Each of these batteries is connected to its respective power panel through an 800 ampere fuse. Batteries 23 and 24 are each rated at 425 ampere hours and are connected to their power panels through 800 ampere circuit breakers.

During normal operation, the loads from each of the power panels are supplied from the output of the associated battery charger, which also provides a constant trickle charge to maintain the battery in a fully charged condition. Each of the battery chargers is a 25 kVA silicon controlled rectifier self-regulating unit cooled by forced air circulation. Protective relays will trip the charger input circuit breaker to prevent the unit from overheating if the cooling fan fails or if inadequate cooling air flow is detected by an internally mounted differential pressure sensor. Each battery charger is directly connected to its associated power panel through the battery charger output supply breaker. An equalizing charge may be applied to the battery at 139.8 VDC (135.1 VDC for battery 22) for up to 24 hours during normal operation without removing either the battery or battery charger from service. The power supply to each of the battery chargers is provided from a source associated with the 480V bus for which that charger supplies DC control power. Battery charger 21 is powered from MCC 29 (which is supplied from bus 5A), battery charger 22 is powered from MCC 24 (bus 2A), battery charger 23 from MCC 22 (bus 3A), and battery charger 24 from MCC 26B (bus 6A). As described in Section 1.5.2.2.1.2.2.2.4, the supply to battery charger 24 remains energized whenever bus 6A is energized. The supplies to battery chargers 21 and 22 are stripped on any station blackout condition and must be manually reenergized. The supply to battery charger 23 is stripped on any station blackout or safety injection signal and must be manually reenergized.

The seven DC voltage sensing relays which will provide automatic transfer capabilities for control power to the 480V switchgear and diesel generators are described in Section 1.5.2.2.1.2.2.2.4.

Batteries 21, 22 and 24 are located in individual battery rooms at Elevation 33' cable spreading area of the Unit 2 control building. Battery 23 is located in a room next to the cable spreading room. This battery room extends into the Unit 1 superheater building, which is part of the combined Unit 1/Unit 2 turbine building structure. All four power panels are mounted on the exterior walls of the battery rooms in the control building, and the distribution panels are surface mounted at the rear of the Unit 2 control panels in the control room. The battery chargers are located in the cable spreading room at Elevation 33' in the control building.

1.5.2.2.1.2.2.4 Auxiliary AC power subsystems

1.5.2.2.1.2.2.4.1 480V motor control centers. All station 480V loads rated at 100 horsepower and below are supplied from MCCs powered from the 480V buses, as shown in Figure 1.5.2.2.1-3 and Table 1.5.2.2.1-3. All safeguards system motor-operated valves are powered from either MCC 26A or MCC 26B, which remain energized whenever their associated supply buses (5A and 6A, respectively) are energized. The supply breakers to these MCCs also receive automatic confirmatory closing signals on any safety injection actuation and may be operated from the Unit 2 control panels. The supply breakers to all other MCCs are operated locally at the 480V switchgear by manual close and trip pushbuttons.

As described in Section 1.5.2.2.1.2.2.2.4, various MCC feeds are stripped from the associated supply buses during three major station loss of power conditions. Following this automatic stripping, the affected MCCs must be manually reenergized at the 480V switchgear. The MCCs affected by these conditions are:

- Safety Injection With No Blackout: strips all MCC feeds except those to MCCs 24, 26A, 26B, 29, and 211.

- Safety Injection With Blackout: strips all MCC feeds except those to 26A and 26B.

- Blackout With No Safety Injection: strips all MCC feeds except those to 26A and 26B.

MCC 21 is located outdoors at the Unit 2 intake structure and supplies intake auxiliaries such as the traveling screens. MCCs 22 through 25 are located at Elevation 15' in the turbine building and generally supply auxiliaries associated with the conventional plant. MCCs 26A, 26B, and 27 are located at Elevation 98' of the primary auxiliary building. MCCs 26A and 26B supply safeguards system components, and MCC 27 generally supplies nonessential primary plant auxiliaries outside of the containment. MCC 28 is located inside the Unit 2 containment at Elevation 68' and supplies auxiliaries such as the control rod drive cooling fans and the reactor coolant pump bearing lift pumps. MCC 29 is located at Elevation 33' in the control building and generally supplies equipment associated with the building ventilation systems and

transformer auxiliaries. MCC 210 is located in the Unit 1 superheater building and supplies auxiliaries associated with the station service boilers. MCC 211 is located in the Unit 2 auxiliary feedwater pumps building and provides power to the motor-operated main feedwater stop valves for each of the steam generators.

1.5.2.2.1.2.2.4.2 118 VAC instrument power buses. All instrumentation that monitors vital plant parameters and provides input signals to the reactor protection and safeguards actuation systems is supplied from 118 VAC instrument power buses. Instruments providing redundant input signals to the reactor trip and safety injection logic matrices are supplied from separate buses so that failure of any one bus will not prevent a protection function from actuating or cause an inadvertent trip. (A separate inverter powered from 125 VDC distribution panel 21A supplies the instrumentation for channel IV of the containment pressure sensors due to the unique actuation logic provided for the containment spray system.)

Because these instruments require an extremely stable and reliable source of power, each instrument bus is supplied from the output of a static inverter which converts DC power into a very smooth, noise-free AC power signal. A schematic representation of the instrument bus power supply circuitry is shown in Figure 1.5.2.2.1-4. Each inverter is rated at 10 kVA with an output voltage of 118 VAC at 60 hertz. This output will be maintained over a range of input voltage fluctuations from 105 VDC to 140 VDC. The automatic static transfer switch at each inverter unit can replace the inverter output signal with that of the reserve AC power supply within one-eighth of a cycle. This transfer will be initiated under any of the following conditions:

- Undervoltage at the DC supply panel.
- Undervoltage at the inverter output.
- Frequency deviation of 0.3 hertz.

The transfer is automatically blocked if the reserve supply frequency deviates from the inverter output by more than 0.7 hertz. To maintain as smooth a reserve AC supply signal as possible, the 118 VAC power is passed through a constant voltage solatron transformer which filters noise and minimizes voltage fluctuations. There is also an external manual transfer switch that can be used to directly apply the reserve AC power signal to the instrument bus in the event of inverter or static transfer switch failure or required maintenance. This switch has three positions:

1. Off. Reserve AC supply isolated from both the static transfer switch and the instrument bus.

2. Normal. Reserve AC supply available to the static transfer switch.

3. Bypass. Reserve AC supply connected to the instrument bus and isolated from the static transfer switch.

Table 1.5.2.2.1-7 lists the normal and reserve power supplies to each of the instrument buses.

The instrument bus panels are located in the Unit 2 control room behind the flight panel. The static inverters, constant voltage transformers, and manual bypass switches are located at Elevation 33' of the control building in the cable spreading room.

1.5.2.2.1.2.3 Interfacing and Support Systems. The station electric power system provides AC and DC motive control and instrumentation power to all electrically operated components in the plant. The Consolidated Edison transmission network provides the normal source of power to the station through tielines with the Buchanan 138 kV and 13.8 kV substations. One onsite and two nearsite gas turbine units also provide independent sources of power to the station through these offsite tielines and an onsite switchyard.

If all offsite and gas turbine power supplies are unavailable, the Unit 2 electrical power systems can be powered from three independent onsite diesel generator units. The diesel generator starting air compressors and air receivers provide the compressed air supply necessary for diesel engine starting. The diesel fuel oil transfer and station service water systems provide sources of fuel and engine cooling for continued operation.

The safeguards actuation, reactor protection, main turbine-generator protection, and offsite tieline fault protection systems provide signals to the station electric power system for the initiation of automatic bus transfer operations, bus load shedding, diesel generator starting, and automatic bus load sequencing under a variety of transient conditions.

Within the system, the AC and DC subsystems are strongly dependent on one another through the AC powered battery chargers and DC control power supplies to the diesel generators and 6.9 kV and 480V switchgear.

The control room and local plant operators interface directly with the electric power system for remote and local manual circuit breaker operations and manual operation of the diesel generators. Although the system is designed to automatically provide a reliable source of onsite power during a wide range of anticipated events, these manual operations provide added flexibility for realignment of the power supply flow paths as conditions require, and provide the means by which individual components and subsystems may be recovered following severe system transients.

1.5.2.2.1.2.4 Technical Specifications. The Indian Point Unit 2 technical specifications require the following electric power system components to be operable before the unit can be brought above the cold shutdown condition.

- At least two 138 kV transmission circuits to Buchanan substation.
- 6.9 kV buses 5 and 6 energized through the station auxiliary transformer from either 138 kV feeder 95331 or feeder 95332.
- 13.8 kV feeder 13W92 or feeder 13W93 available.
- All four 480V buses energized, with crosstie breakers 2AT5A and 3AT6A open.
- All three diesel generators operable.
- A minimum of 19,000 gallons of diesel fuel in the underground storage tanks, with an additional 22,000 gallons of fuel available onsite.
- Batteries 21 and 22, and their associated DC power panels and battery chargers operable.

The technical specifications allow the following limited inoperability conditions during unit power operation.

- One diesel generator may be removed from service for a period of up to 7 days, provided the remaining two diesel generators are verified to be operable daily and both the 138 kV and 13.8 kV sources of offsite power are available during this inoperability period.
- Unit operation may continue for 24 hours if either the 138 kV or the 13.8 kV source of offsite power is unavailable, provided all three diesel generators are operable. Operation may continue beyond 24 hours in this condition if the NRC is notified of the specific plans in effect for the restoration of the offsite power supply.
- Battery 21 or 22 may be removed from service for 24 hours provided the remaining battery and both battery chargers are operable. The DC power panel for the unavailable battery must be energized from one of the battery chargers during this period.

In addition to these operability requirements, at least one of the three gas turbine-generators must be operable at all times with a minimum of 54,200 gallons of fuel available. All three gas turbines may be removed from service for a period of up to 7 days. If at least one of the gas turbine-generators is not returned to service within this period, an alternate independent power supply must be provided or the unit must be placed in hot shutdown. If the degraded operability condition lasts longer than 48 hours with the unit at hot shutdown, the unit must be brought to cold shutdown.

1.5.2.2.1.2.5 Testing Requirements. To minimize the unavailability of electric power system components during unit operating periods, all periodic testing at Indian Point Unit 2 requiring that an electrical system component be removed from normal service is performed during cold shutdown or refueling periods. The major periodic tests performed on the electric power system are summarized in the following. The numbers

in parentheses refer to the specific Indian Point Unit 2 procedure under which the given test is performed.

- A visual inspection of each diesel generator is performed daily. This inspection verifies and records satisfactory lube oil level, fuel oil day tank level, service water cooling flow, starting air pressure, and overspeed trip mechanism status (PT-D1).

- A visual inspection and check of each diesel generator is performed weekly to verify its availability for automatic operation, to check operation of the starting air compressor, to check for water and oil leaks, and to record the volume of fuel oil stored onsite (PT-W1).

- Each diesel generator is started manually and loaded onto its associated 480V bus in parallel with the normal bus power supply once each month. The diesel generator is operated at a load of approximately 500 kW for 1 to 2 hours (PT-M21). (This testing has been recently changed in conformance with NRC Regulatory Guide 1.108. The analysis of the diesel generators performed in this study does not take credit for these revised testing procedures and frequencies.)

- The terminal voltage, individual cell voltage, pilot cell electrolyte specific gravity, and electrolyte level are measured and recorded once each month for each station battery (PT-M22).

- One of the three gas turbines is started and run at a minimum load of 750 kW for at least 30 minutes each month (PT-M38).

- Each station battery is inspected and placed on a equalizing charge for 24 hours once each quarter (PT-Q1).

- The mechanical overspeed trip setpoint of each diesel generator is functionally tested once each quarter (PT-Q6).

- The DC control power automatic transfer switches for each of the diesel generators are functionally tested once each quarter (PT-Q9).

- Each battery is disconnected from its power panel and discharged into a load resistance bank for a period of 8 hours to verify its ampere hour capacity once each refueling outage (PT-A4).

- A safety injection with blackout signal is simulated during each refueling to verify the automatic starting of each diesel generator and the operation of the 480V bus load shedding and associated load sequencing control circuits (PT-R14).

- Each diesel generator is started manually and loaded onto its associated 480V bus in parallel with the normal bus power supply once each refueling. The diesel generator is operated for 1 to 2 hours at its rated load of 1,750 kW (PT-R20).

- If one of the diesel generators is unavailable for service during unit operation, the remaining two diesel generators are started daily to verify their continued operability (for a maximum allowable period of 7 days). The diesel generators are not loaded onto their buses during these nonroutine operability checks.

1.5.2.2.1.2.6 Maintenance Requirements. Except for the diesel generators, routine preventive maintenance performed on components of the electric power system is generally scheduled for cold shutdown periods during which the electrical load on the system is reduced and the technical specification component inoperability time limitations are relaxed. Repairs of failed or degraded components made during unit operating periods must conform with the applicable technical specifications system operability criteria, or the unit must be shut down until the failed components are returned to service. For most maintenance performed on individual 6.9 kV and 480V switchgear circuit breakers, the breaker is removed from its cubicle. During these periods, a spare breaker is normally installed and the associated buswork remains energized. Maintenance on other system components can also generally be performed without affecting the flow of power to the station loads using the manual bus tie interconnections and installed reserve power supplies.

Because of their complexity, frequent testing, and vital status as emergency power supplies, the diesel generators are subject to more frequent nonroutine and scheduled preventive maintenance than are most other components in the plant. Routine maintenance performed on the diesel generators during unit operation includes preventive maintenance items such as the repair of minor cooling water and oil leaks, replacement of oil filters, calibration of electrical and mechanical control systems, etc. The technical specifications also require that a major inspection and general overhaul of each diesel generator be performed annually in accordance with the manufacturer's recommendations.

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1.5.2.2.1.3 Logic Model.

1.5.2.2.1.3.1 Top Events Definition. The Indian Point Unit 2 electric power system is analyzed for the 16 operability states listed in Table 1.5.2.2.1-1. Each of these states is developed for the two general boundary conditions of offsite power available and offsite power not available.

The event trees developed for Indian Point Unit 2 analyze the loss of offsite power as an initiating event which causes a unit trip. This condition requires failure of the 345 kV transmission system to the extent necessary to cause an automatic generator trip or to require manual operator action to trip the unit. Because the 138 kV supply from Buchanan substation is the normal source of offsite power to Unit 2, the loss of offsite power also requires failure of this supply. The analysis of the Unit 2 electric power system described in this study has been developed as a conservatively bounding failure quantification for the purposes of identifying the dominant event sequence contributors to risk. As such, manual operator actions are excluded from this analysis but will be included during the assessment of recovery from the dominant failure sequences during event tree quantification. Because the 13.8 kV power supply from Buchanan and the three gas turbines require manual switching operations before they can energize any of the Unit 2 buses, the status of these supplies does not affect the condition of "offsite power" as applied in this analysis. (Their status significantly affects the time required to recover power to the essential buses from a source other than the diesel generators and, therefore, is vital to the quantification of failure recovery.) For this study, "offsite power" is defined to specifically include the following two items:

1. The 345 kV transmission system from Unit 2, to the extent that failures will necessarily result in a unit trip.

2. The 138 kV supply to Unit 2 from Buchanan substation.

Failure of "offsite power" requires failure of both of these elements as a minumum condition. The failure of "offsite power" to Unit 2 does not define the status of either of the 13.8 kV supply lines from Buchanan or of any of the gas turbine units. It may include failure of any, all, or none of these additional power sources. The status of these sources is important only in the quantification of the time required for onsite electric power recovery. The effects of the unavailability of these supplies will be quantified explicitly as they affect recovery from the dominant event sequences. The unit specific electric power system model developed in this analysis includes the station auxiliary transformer. Failures of this component are, therefore, not included in the definition of failure of "offsite power" and are quantified separately in the unit power supply availability analysis.

The electric power system is normally in service during all modes of unit operation. For this study, it is considered to be in its normal configuration (all buses energized from their normal power sources)

immediately before the initiation of any of the event sequences in the event trees. Those electric power system failures which produce any of the plant transients analyzed in the event trees are identified and quantified in the initiating event analysis section of this study. A summary of these failures and the corresponding initiating events is presented in Table 1.5.2.2.1-8. Any failure causing loss of power which does not lead directly to an initiating event will be quickly detected by plant personnel because of its effects on auxiliary equipment operation. These failures will either be quickly repaired or the unit will be shut down in conformance with the technical specifications operability criteria or normal operating procedures and practices. The probability of any other initiating event not associated with the loss of power occurring during this recovery period is very small compared with the probability of event initiation due to electric power failure. Therefore, the electric power system is analyzed for its unavailability conditional on the following criteria:

- An initiating event has occurred.
- The electric power system was available in its normal configuration immediately before event initiation.

Although it is desirable for the electric power system to remain in continuous operation for the duration of each of the event sequences analyzed in this study, a time period during which failures are less tolerable and may be critical to overall plant recoverability exists for each general initiating event category. The duration of this period is determined by factors such as the magnitude and type of initiating event, the operation of automatic mitigation systems, the response times of plant personnel, characteristic periods associated with core nuclear physics, primary and secondary thermal hydraulics, etc. In principle, each sequence studied presents a unique timeframe beyond which electric power failures are relatively more tolerable because of increased recovery times, the availability of additional personnel, reduced decay heat levels, and the establishment of a stable and well controlled core condition. To develop electric power unavailability information to be applied to the entire spectrum of event sequences studied, this electric power system failure analysis is extended for a nominal time period of 6 hours following event initiation. This period is considered to be a conservative representation of the time required to place the unit in a stable configuration so that core nuclear and thermal transients are relatively slow and the available time for system and plant recovery is extended. For the majority of sequences analyzed, stable shutdown will be achieved within a significantly shorter time period, and application of the results of this 6-hour failure analysis provides a conservative estimate of system unavailability. For those event sequences in which the unavailability of electric power is a dominant contributor to overall risk, the analysis will be refined to incorporate a more detailed time model of both failure and recovery phenomena in the context of each specific event scenario.

A second major factor in the overall conservatism of the electric power system analysis is that no credit is taken for manual operator action or

general system recoverability for the 6-hour study period. The response of the plant operators to any failure is strongly dependent on the specific conditions existing when the failure occurs. Failures may be massive and confusing or relatively minor. The operators may find themselves in the midst of a rapid sequence of events requiring almost immediate correct response or in a relatively slow transient during which even major component failures are tolerable. These event specific constraints must be coupled with the characteristic times required to effect recovery, as determined by the specific failure states analyzed. Thus, it is evident that the application of even the most simple recoverability factors for the electric power system cannot be taken out of the context of the event sequences during which the failures are postulated to occur. Assessment of the electric power system unavailability with no recovery provides a very conservative estimate of system response in the determination of the dominant contributors to risk. As discussed previously, once the dominant sequences are identified, the quantification of each of these sequences will include a detailed model of time dependent failure and recovery applied within the context of each specific postulated scenario.

The top event definition for each of the electric power system operability states is of the form "Failure to Maintain Bus(es) - Energized for a Period of 6 Hours Following Event Initiation," given that the electric power system was available immediately before event initiation and no efforts are made to recover any failed equipment.

1.5.2.2.1.3.2 System Fault Tree. Fault tree logic is used in this analysis to aid in the identification of those combinations of component failures which are necessary to produce overall system failure within the context of each specified operability state and boundary condition imposed on the system. Figure 1.5.2.2.1-5 shows the fault tree developed for the Indian Point Unit 2 electric power system. To facilitate the synthesis of the various system operability states analyzed in this study, the tree is drawn so that the failure of power at a single 480V bus can easily be extracted and combined with other buses to form a tree that is unique to each operability state.

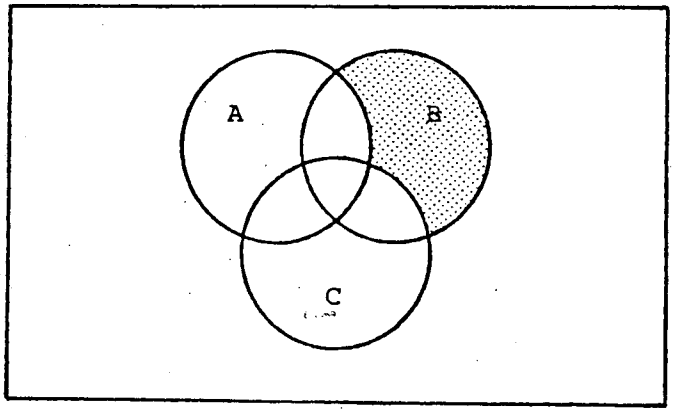
The fault tree is developed for all components of the station 6.9 kV, 480 VAC, 118 VAC, and 125 VDC subsystems which provide motive and control power to each of the safeguards systems analyzed in this study. It extends to the level of detail that is necessary to illustrate the electrical power supply components that provide a direct interface with the corresponding mechanical system components (e.g., motor control centers and 120 VAC distribution panels). All available bus ties and alternate power supply paths are specifically included to model the subsystem interdependencies. The fault tree does not include those components and subsystems which do not supply power to any systems analyzed in this study (e.g., 6.9 kV buses 1 and 4, several auxiliary motor control centers, etc.).

As shown, the system fault tree includes all component failure modes which contribute to system failure and is a complete representation of

the system hardware failures which are both necessary and sufficient to achieve the top event for any of the failure states analyzed. The fault tree does not include descriptions of the causes for these failures because a given component failure mode may be initiated through a wide variety of cause sequences. Similarly, the fault tree does not include manual recoverability operations which can lead to either repair or circumvention of these failures. These causes and recoverability factors are quantified in the context of the specific fault tree that is constructed for each failure state as they affect the specific hardware configurations relevant to that state.

1.5.2.2.1.3.3 System Failure State Synthesis. There is a unique fault tree that corresponds to each system operability state for each boundary condition imposed on the electric power system. Thus, there are 32 different top events for which system failure must be analyzed. To identify the component failure combinations contributing to each of these 32 cases, portions of the system fault tree shown in Figure 1.5.2.2.1-5 are combined to form a fault tree which uniquely describes the system hardware configuration applicable to each case under consideration.

For the application of the results of this electric power system analysis to be logically complete, each of the quantified system operability states must be mutually exclusive. For example, the calculated unavailability of power at bus 5A applied in the analysis of the event sequences must represent the condition that power is lost <u>only</u> at bus 5A (i.e., that buses 2A, 3A, and 6A remain energized). In principle, a complete mathematical expression which allows direct calculation of each of the mutually exclusive unavailabilities may be developed from the system logic model. However, in practice, the complexities of the system hardware configurations and the need to carefully compute several levels of conditional probabilities preclude the direct calculation of these mutually exclusive states. Therefore, the computation methodology of this analysis uses the system logic model to develop a complete mathematical expression of the failure modes necessary and sufficient to achieve each desired failure state without regard to the possible impact of the failures on other system states. The desired set of mutually exclusive failure states is then quantified by applying a simple logic expression to these nonmutually exclusive analysis results. The process is completely analagous to the determination of the mutually exclusive contributions to the problem represented by the following Venn diagram.



The area of the shaded portion of circle B (i.e., the mutually exclusive condition represented by "B and only B") is desired. If it is a relatively straightforward problem to compute the area of each of the three large circles and of each of the intersections, then the answer to the problem is determined through the logical expression:

$$\text{Shaded Area} = B - (A \wedge B) - (B \wedge C) + (A \wedge B \wedge C)$$

By following this approach, the electric power system analysis task is made mathematically simpler and logically complete. All possible failure contributors are explicitly included in each of the nonmutually exclusive unavailability expressions. This minimizes the chances for omission or miscalculation of conditional events. The simple application of basic logic principles then ensures that the mutually exclusive failure state representations are complete.

As an example of the methodology used in the development of the nonmutually exclusive failure state fault trees, consider the case for which the top event definition is "Failure of Power at Buses 2A and 6A Given Offsite Power Available." The fault trees for failure of power at bus 2A and failure of power at bus 6A are combined with the following "house events" specified to define the applicable boundary conditions under which the system is analyzed.

- Offsite power is available to the station auxiliary transformer.
- The diesel generator operating mode selector switches are specified as being in the correct positions for automatic starting.
- Circuit breakers requiring manual operator action to close, such as the gas turbine feed breakers GT-25 and GT-26 and the 480V bus crosstie breakers 2AT5A and 2AT3A, are specified to remain open

because the tree is developed only for hardware failure contributions to unavailability.

- The diesel generator feed breakers to buses 2A and 6A (EG2A and EG3) receive automatic signals to close under these conditions.

The resulting failure state fault tree is then analyzed to determine the minimal combinations of hardware failures which result in the failure of power at both buses 2A and 6A. These minimal component failure combinations are then used to develop an unavailability expression for the quantification of the hardware failure contributions to this scenario.

1.5.2.2.1.3.4 Fault Tree Coding. Table 1.5.2.2.1-9 presents a list of the basic events in the electric power system fault tree, the corresponding component failure modes, and the applicable failure rates.

1.5.2.2.1.4 Quantification. The unavailability of the Indian Point Unit 2 electric power system is quantified for each of the 16 system operability states listed in Table 1.5.2.2.1-1 under each of the general boundary conditions discussed in Section 1.5.2.2.1.2.6. To illustrate the relative contributions to system failure from active component failures (i.e., failures on demand) and from component failures during operation, a nominal reference operating period of 6 hours following event initiation is applied to each of the cases analyzed. Detailed time dependent conditional failure probabilities are not developed. Instead, an upper bound for system failure is determined by applying a uniform failure rate for each component over the entire study period (i.e., components, "X" and "Y" are allowed to fail at any time during the 6-hour period, even though component "Y" may not be called on to operate until component "X" has failed).

1.5.2.2.1.4.1 Hardware Failures. The component hardware failure contribution to system unavailability is quantified under the following analysis criteria:

- An initiating event has occurred.
- Power is unavailable from the main generator.
- The electric power system was in its normal configuration according to plant operating procedures immediately before event initiation.
- No operator intervention is considered during the study period.

The effects on component operation of the boundary conditions imposed on the system are described in the applicable analyses presented in Section 1.5.2.2.1.4.5. Recovery actions that require operator intervention are not included in the quantification of the hardware failure contributions because they are strongly dependent on the time available for response, the specific event scenario (due to varying degrees of urgency and operator distraction imposed), and because any operator action will alter the system hardware configuration and component operating characteristics from those observed in an analysis of hardware failures alone.

Therefore, the calculated system unavailability contribution from hardware failures represents a conservative upper bound which may be reduced by operator intervention in the context of the specific boundary conditions and event scenarios. A general discussion of these time dependent recoverability factors is presented in Section 1.5.2.2.1.4.5.

1.5.2.2.1.4.2 Testing Contribution. Of the tests summarized in Section 1.5.2.2.1.2.4, only actions performed during the diesel generator operability tests contribute to electric power system unavailability during noncold shutdown unit operating periods. During the monthly functional tests (PT-M21), the three diesel generators are started in succession and are operated under load for 1 to 2 hours. These tests are performed from the local control panels in the diesel generator building.

Because each diesel generator is running and is attended during these operability tests, the diesel generators remain available for emergency service throughout the testing periods. However, the performance of these tests requires that the diesel generator engine control switches be removed from the "Auto" position. (The switch is placed in "Manual" for local starting of the diesel engine and is turned to "Off" for shutdown of the diesel at the conclusion of the test.) If, after testing, the switch is left in any position other than "Auto," the switch inhibits an automatic starting signal from reaching the diesel engine control system and thus makes the unit unavailable for automatic emergency service. Removal of the switch from the "Auto" position is annunciated in the Unit 2 control room. All test procedures include a step that requires that the switch be returned to the "Auto" position following engine shutdown.

The section on human error rates in the methodology section of the main study presents the following lognormal distribution for the frequency of an operator omitting a step while using a procedure with check-off provisions:

Mean: $\phi_{WP} = 2.2 \times 10^{-3}$ failures/test

Variance: 1.9×10^{-5}

If the control switch is left in the wrong position at the end of the test, the control room annunciator will stay lighted to alert the control room personnel of this condition. (The annunciator alarms when the switch is initially removed from "Auto" at the start of the test and stays lighted throughout the test until the switch is returned to "Auto.") If the control room operator fails to respond to this annunciator, the switch will remain mispositioned, and the diesel generator will be unavailable for automatic operation. Neither the methodology section of this study nor the human reliability handbook (NUREG/CR-1278) specifically addresses the issue of an operator failing to respond to an annunciator which stays lighted for some time following its expected receipt. Therefore, the following distribution has been assigned as a conservative estimate of the total time required for the control room operator to respond to the lingering annunciator and for a local operator to return the control switch to the correct position.

Time to Restoration of Switch	Frequency
<1 hour	0.750
1 - 12 hours	0.225
12 hours - 7 days	0.024
7 days - 30 days	0.001

If a switch is left in the wrong position, most of these recovery actions will take place within an hour following completion of the test. Although this action may be taken within a few minutes, factors such as other tasks being performed by the control room operators, time

delays in communicating with the local operator, the local operator's response time to the diesel generator building, and the perceived urgency of clearing these alarms may all contribute to extending the reaction period. A 75% recovery rate within 1 hour is believed to be very conservative and is applicable to this bounding system analysis. If the operators on shift at the time of testing fail to respond to the alarm, then it is very likely that the operators on the next shift will investigate the situation if they recognize it as an abnormal condition. (However, if the preceding shift did not respond to the annunciator, they would probably not tell the incoming shift that an abnormal condition existed.) The new operators are likely to notice the annunciator during their review of the control boards, but may delay their response or instruct the local operators to investigate the problem at their convenience because of factors such as sensitivity to spurious alarms, perceived urgency, additional tasks, etc. It is believed that a 97.5% frequency of recovery within 12 hours is also very conservative for this analysis. If the alarm persists for several days, successive new shifts of operators will be exposed to the condition. However, it is possible that, due to unforeseen circumstances (which could include annunciator signal failure), the control switch could remain mispositioned for the entire 30-day period between tests. The mispositioned switch would be discovered during any diesel generator tests performed during this intervening period, but credit is taken only for the regularly scheduled monthly operability tests, as this is the maximum period during which this condition could persist.

The diesel generators are visually inspected each day (PT-D1). However, this inspection does not specifically require the verification of alignment for automatic operation. Because the mispositioned switches are not annunciated locally, it is unlikely that switches would be detected in the wrong position during these daily checks. (The local operators will rely on the control room annunciator to alert the control room personnel to this condition.) A weekly inspection of each diesel generator is also performed during which the local inspectors are instructed to verify that the diesel generators are available for automatic operation (PT-W1). The distribution presented previously assigns a 99.9% frequency to the discovery of a mispositioned switch within 7 days because of the control room annunciator. The weekly inspection will reduce the recovery failure frequency during the period of 7 to 30 days, but the effects are minor and, in the interest of conservatism, are not specifically quantified in this analysis.

The unavailability of a diesel generator due to its control switch being left in the wrong position at the completion of a monthly test is obtained by multiplying the distribution for failure frequency ($\phi_{WP}/720$) by the distribution for the time to discovery. The resulting lognormal distribution for the unavailability of a diesel generator due to these testing errors is:

Mean: $Q_{TE1} = 2.5 \times 10^{-5}$

Variance: 7.20×10^{-9}

This distribution is believed to be very conservative for the reasons outlined previously in the development of the recovery distritution.

During each monthly test, all three diesel generators are tested in succession. If the local test personnel leave one control switch mispositioned at the end of a test, it is possible that they could leave two or all three switches mispositioned. Because the same people perform all three tests and use the same test procedure, there is at least a moderate dependence among these failures. Thus, if one switch is mispositioned, the second and third switches will be left in the wrong positions at a higher frequency than if each of the diesel-generator tests were completely independent. There is also some dependence for the control room operator's failing to respond to the annunciated conditions. Although several alarms are lighted, the control room operator may decide to have them all cleared at the end of the test, he may be distracted by other operations, etc. Therefore, the overall effect of the combined actions of the local test personnel and the control room operators is a low dependence between the unavailability of one diesel generator due to a mispositioned control switch and the unavailability of two or three diesel generators. The quantification of this dependence is extremely difficult.

The section on human error rates in the methodology section of the main report provides an analytical expression which models this low dependence between errors made during task N and the error rate for the preceding task N-1.

$$\gamma_N = \frac{1 + 19\gamma_{N-1}}{20}$$

The development and application of this relation are discussed in the methodology section. It is used in this analysis to quantify the coupling between the medians of the unavailability distributions resulting from these dependent testing errors. As discussed in the development of this expression, an error factor of 5 is assigned to the resulting distribution for γ_N to express the uncertainty about this relation. The median of the lognormal distribution presented in the preceding for the unavailability of a single diesel generator is $\gamma_{N-1} = 9.72 \times 10^{-6}$. Using this value in the low dependence coupling expression and application of the error factor results in the following distribution for the conditional unavailability of a second diesel generator, given that an error has been committeed following testing of the first unit:

Median: 5.00×10^{-2} error/second event, given an initial error

Mean: 8.07×10^{-2} error/second event, given an initial error

Variance: 1.05×10^{-2}

The unavailability of both diesel generators due to these weakly coupled errors is determined by multiplying the conditional unavailability distribution for the second diesel generator by the distribution for error-produced unavailability of the first unit. The resulting distribution for the unavailability of two diesel generators due to mispositioned control switches is:

Mean: $Q_{TE2} = 2.03 \times 10^{-6}$

Variance: 2.34×10^{-11}

Application of the weak coupling expression to determine the conditional unavailability of a third diesel generator, given the condition that errors have occurred during the testing of two diesel generators, results in the following distribution for the unavailability of three diesel generators due to mispositioned switches:

Mean: $Q_{TE3} = 1.63 \times 10^{-7}$

Variance: 2.02×10^{-13}

The coupling factor is believed to be a very conservative estimate of the dependence among these specific testing and annunciator response errors. Therefore, the resulting unavailabilities for two and three diesel generators due to these errors are considered to be bounding values.

1.5.2.2.1.4.3 Maintenance Contribution. The only maintenance which contributes to the unavailability of the electric power system during noncold shutdown unit operating periods is that which is performed on the diesel generators. The Indian Point Unit 2 technical specifications allow a single diesel generator to be removed from service for maintenance for a maximum of 7 days, provided the remaining two diesel generators are operable and are started daily, and that both the 138 kV and 13.8 kV sources of offsite power are available throughout this period. The unit must be shut down if more than one diesel generator becomes inoperable. Maintenance Data Table 1.5.1-21 and Figure 1.5.1-22 provide the following information for diesel generator maintenance:

- The frequency of diesel generator maintenance is given by the lognormal distribution:

  Mean: 9.05×10^{-4} maintenance events/hour/diesel generator

  Variance: 1.85×10^{-8}

- The mean unavailability of each diesel generator due to maintenance is 3.02×10^{-2}. To directly apply the unavailability information presented in Figure 1.5.1-22 to this analysis, the smooth curve was discretized to produce the following histogram:

Generator Unavailability	Probability Density
0.020	0.104
0.025	0.302
0.030	0.315
0.035	0.137
0.040	0.066
0.045	0.039
0.050	0.024
0.055	0.013

1.5.2.2.1.4.4 Diesel Fuel Oil Supply Failure. One contributor to the failure of a diesel generator to remain in operation for periods in excess of approximately 1 hour is the failure of the fuel oil transfer system to maintain a supply of fuel to the diesel engine from the underground storage tanks. The diesel generator fuel oil day tanks are checked daily to verify that they contain a minimum of 115 gallons of fuel each (PT-D1). This is enough fuel to operate a diesel generator at full load for approximately 55 minutes. For periods that extend beyond this limit, fuel oil must be transferred from the underground storage tanks to the day tanks by the fuel oil transfer pumps. Fuel oil transfer pump 21 receives a signal to automatically start at a level of approximately 115 gallons in the diesel generator 21-day tank, and pump 23 receives a starting signal if the day tank level continues to decrease. Similar dual pump starting sequences are provided for refilling the day tanks for diesel generators 22 and 23. (The pump starting logics are summarized in Table 1.5.2.2.1-5.) A low-low fuel oil level alarm is activated at the diesel generator panels if a day tank level drops to 52 gallons (which is approximately 24 minutes diesel generator operating reserve time). This alarm is also received in the Unit 2 control room at the common annunciator window for diesel generator trouble.

With all three diesel generators operating at full load, the total fuel consumption rate is approximately 7 gallons per minute. A single transfer pump can provide this capacity and can supply all three diesel engines simultaneously through the common fuel oil supply piping.

The power supplies to the fuel oil transfer pumps are listed in Table 1.5.2.2.1-4. These motor control centers are automatically stripped from their associated 480V supply buses and are deenergized under the following conditions:

- Unit Trip With Blackout (undervoltage on bus 5A or bus 6A): strips MCCs 24, 27, and 29 (all transfer pumps deenergized).

- Safety Injection Without Blackout: strips MCC 27 (transfer pump 23 deenergized).

- Unit Trip Without Blackout: no MCCs stripped.

Following these automatic signals, the MCCs must be manually reenergized by locally closing their supply breakers at the 480V switchgear. The Indian Point Unit 2 emergency core cooling system actuation Emergency Procedure E-2 specifies that power must be restored to MCCs 24, 27, and 29 within one-half hour following the safety injection, if the diesel generators are operating, to ensure that power is maintained to the fuel oil transfer pumps. The loss of offsite power Emergency Procedure E-4 specifies that all MCCs should be reenergized following the stabilization of diesel generator loading, but does not identify MCCs 24, 27 and 29 as being critical for the continued operation of the diesels. If the diesel generators run out of fuel when offsite power is not available, no source of power is available to the transfer pumps, and neither the fuel oil pumps nor the diesel engines can be operated until an auxiliary power supply is established.

A given transfer pump will fail to supply fuel to the diesel generators if any of the following conditions occur:

- The MCC supplying power to the pump is automatically stripped from its 480V bus and is not reenergized.

- Power fails at the 480V bus supplying the pump MCC.

- With power available, the pump fails to start on demand or fails during operation.

All initiating events analyzed in this study are assumed to cause a trip of the main generator. The diesel generators receive automatic starting signals whenever an undervoltage condition is detected at any 480V bus or following any safeguards actuation. However, the diesel generator output breakers receive automatic closing signals only if voltage is lost at 480V bus 5A or bus 6A. As discussed in the preceding, this "blackout" condition automatically opens the supply breakers to MCCs 24, 27, and MCC 29. The emergency procedures and the diesel generator trouble annunciator, which will alarm as the fuel oil day tanks reach the low-low level setpoint, will alert the control room operator of the need to restore power to the MCCs. The human error section of the methodology section in the main study provides the following lognormal distribution for the omission of a procedural step:

Mean: $P_{PR} = 2.2 \times 10^{-3}$ failures/event

Variance: 1.9×10^{-5}

Although the operators using the emergency procedures are performing under at least moderate stress, which would tend to increase this failure frequency, it is felt that the high priorities assigned to the

restoration of power will tend to counterbalance these stress effects for this specific action. The need to restore power to these MCCs is not immediate; it must be accomplished within 45 minutes to 1 hour following the blackout to prevent fuel supply failure. Therefore, it is believed that the given distribution for procedural step omissions adequately models the failure frequency for control room personnel under these conditions.

If power is not restored to the MCCs, the fuel oil day tanks will reach the low-low level alarm setpoint after approximately 30 minutes of diesel generator operation. This alarm will be received in the control room and will provide the operators with an independent "reminder" to restore power to the fuel oil pump MCCs. (Approximately 20 to 25 minutes of diesel generator operating time remains before the day tanks will be completely drained.) Table 20-4 in the human reliability handbook (NUREG/CR-1278) provides frequency bounds of 3×10^{-4} to 3×10^{-2} for operator failure to respond to a given annunciator, assuming that approximately five annunciators are alarming. This is considered to be conservatively representative of the conditions 30 minutes following an initiating event. Using these bounds as the 5th and 95th percentiles of a lognormal distribution, the failure frequency for response to the diesel generator trouble annunciator is:

Mean: $P_{AN} = 7.99 \times 10^{-3}$ failures/event

Variance: 3.89×10^{-4}

If the control room operator reacts to either the procedural guidance or trouble annunciator, there is enough time to notify the local plant operators and to reenergize the fuel pump MCCs. Therefore, the frequency of failures of plant personnel to take actions to restore MCC power before the diesel generators run out of fuel is determined by:

$P_{NR} = (P_{NR})\ (P_{AN})$

Mean: $P_{NR} = 1.76 \times 10^{-5}$ response failures/event

Variance: 1.87×10^{-9}

To restore power to the fuel pump MCCs, the operators must manually reclose the MCC supply breakers at the 480V switchgear. If these breakers fail to close or if the 480V bus is deenergized, power will remain unavailable to the transfer pumps. Component Failure Data Table 1.5.1-4, item 29, provides the following distribution for circuit breaker failures to close on demand:

Mean: $P_{BF} = 2.46 \times 10^{-5}$ failures/demand

Variance: 1.84×10^{-8}

Although this failure rate includes failures of automatic closing signals, auxiliary contacts, etc., and may be somewhat conservative for local manual breaker operations, no data are available for these manual failures. Therefore, the given distribution is retained as an upper bound for the failure of an MCC supply breaker to close on demand.

No specific generic data are available in this study for failures of diesel fuel oil transfer pumps. A review of the component failure data summaries for a wide variety of motor driven pumps receiving automatic starting signals indicates that a median value of 2×10^{-3} is representative of the combined rate for these pumps failing to start on demand and to remain in operation for at least 6 hours. Assigning an error factor of 5 to represent the uncertainty in this value results in the following lognormal distribution for fuel oil transfer pump failures, given that power is available at the pump MCC:

Mean: $P_{PF} = 3.23 \times 10^{-3}$ pump failures/event

Variance: 1.67×10^{-5}

1.5.2.2.1.4.4.1 Fuel supply with offsite power not available. The loss of offsite power, as defined in this study, will result in a trip of the Unit 2 main generator. Therefore, all three fuel oil transfer pump MCCs are initially stripped from their respective 480V buses. If the plant operators respond to restore power to the MCCs, each MCC may remain deenergized if any of the following failures occur:

- No power is available from the diesel generator (due to diesel generator failure or unavailability when the loss of offsite power occurs).
- Malfunction of the diesel generator output breaker.
- Failure of the 480V bus.
- Malfunction of the MCC supply breaker (including failure to reclose).
- Failure of the MCC.

If the plant personnel fail to respond, all three MCCs will remain deenergized.

An analysis of the Indian Point Unit 2 electric power system has provided the following distributions for the unavailability of power at these MCCs if offsite power is not available:

Unavailability of power at one MCC:

Mean: 4.8×10^{-2}

Variance: 1.2×10^{-4}

Unavailability of power at two MCCs:

Mean: 1.5×10^{-3}

Variance: 2.7×10^{-7}

Unavailability of power at all three MCCs:

Mean: 4.3×10^{-5}

Variance: 4.8×10^{-10}

These distributions include contributions from diesel generator failures, maintenance and testing unavailability, and the failures of circuit breakers and buswork discussed previously. They are conditional on the response of the operators and their attempts to reclose the MCC supply breakers. Supply breaker reclosure failures (P_{BF}), are included. The distributions are also conditional on the availability of fuel to the diesel generators. The results of the analysis presented in this section will provide the fuel failure contribution to diesel generator unavailability. This will then be included in the full quantification of power unavailability.

The dominant contributors to the power unavailability distributions presented in the preceding are diesel generator failures and unavailability due to maintenance. Some of the failures contributing to these distributions will result in a loss of power at an MCC with the associated diesel generator remaining in operation (e.g., failures of the MCC supply breaker). For the analysis presented in this section only, the power unavailability distributions are assigned directly to the diesel generators. This approach is conservative, because it reduces the frequency of fuel oil transfer pump starting signals. The equivalent diesel generator unavailability distributions to be applied to this fuel supply failure analysis are:

Unavailability of one diesel generator:

Mean: $Q_{1DG} = 4.8 \times 10^{-2}$

Variance: 1.2×10^{-4}

Unavailability of two diesel generators:

Mean: $Q_{2DG} = 1.5 \times 10^{-3}$

Variance: 2.7×10^{-7}

Unavailability of all three diesel generators:

Mean: $Q_{3DG} = 4.3 \times 10^{-5}$

Variance: 4.8×10^{-10}

To evaluate the fuel supply failure contribution to diesel generator unavailability, it is important to recognize that two significant effects result from the failure of a diesel generator.

1. Power is lost at the associated 480V bus and its MCCs. This disables the fuel oil transfer pump powered from the failed diesel generator's power supply division.

2. The failed diesel generator does not consume any fuel. Therefore, its day tank level will either not fall below the transfer pump starting setpoint or, if the diesel generator failure occurs with a low level in the day tank, the tank will be refilled to above the low level setpoint and the pump starting signal will be blocked. In either case, neither the primary nor the backup transfer pump for the failed diesel generator will receive sustained operating signals from the affected day tank.

Any one of the transfer pumps can refill all the day tanks through the common fuel supply piping. Therefore, to maintain a supply of fuel to all three diesel generators, only one of the three transfer pumps must operate.

1.5.2.2.1.4.4.1.1 Fuel contribution to unavailability of diesel generator 21. If diesel generator 21 fails due to causes other than inadequate fuel supply, the need for a continuous supply of fuel oil to the diesel engine is eliminated. Therefore, the evaluation of the fuel supply contribution to diesel generator 21 unavailability must be performed under conditions in which the diesel generator is operating. For failure of fuel to diesel generator 21, any one of the following events must occur:

- Failure of the operators to respond to reclose the MCC supply breakers [P_{NR}].

- If all three diesel generators are operating, all three fuel oil transfer pumps should receive automatic starting signals, because all three fuel oil day tanks are being drained at approximately the same rate. Because any one pump can supply all three diesel generators, the failure of the fuel supply under these conditions requires failure of all three transfer pumps. For this analysis, the probability that all three diesel generators are operating is approximated by the factor

  $$[1 - (3Q_{1DG} + 3Q_{2DG} + Q_{3DG})]$$

  and the total contribution to fuel unavailability is

  $$\left[1 - \left(3Q_{1DG} + 3Q_{2DG} + Q_{3DG}\right)\right]\left[\left(P_{PF}\right)^3\right]$$

- If diesel generator 22 is unavailable, transfer pump 22 will remain deenergized. However, transfer pumps 21 and 23 will have power

available to them and will receive automatic starting signals. The unavailability of fuel to diesel generator 21 under this condition is given by

$$\left[Q_{1DG}\right]\left[\left(P_{PF}\right)^2\right]$$

- If diesel generator 23 is unavailable, transfer pump 23 will remain deenergized. However, transfer pumps 21 and 22 will have power available to them and will receive automatic starting signals. (Although transfer pump 22 does not receive a signal from the diesel generator 21 day tank, its operation to supply fuel to diesel generator 22 will also serve as a supply to diesel generator 21.) The unavailability of fuel to diesel generator 21 under this condition is

$$\left[Q_{1DG}\right]\left[\left(P_{PF}\right)^2\right]$$

- If diesel generators 22 and 23 are unavailable, transfer pumps 22 and 23 will be deenergized, and transfer pump 21 will provide the only source of fuel to diesel generator 21. Fuel failure is quantified by

$$[Q_{2DG}]\,[P_{PF}]$$

Any other failure states involve failure of diesel generator 21 and, therefore, are not relevant to this analysis. The total expression for the unavailability of fuel to diesel generator 21 is the sum of the individual contributions derived in the preceding,

$$Q_{F1} = P_{NR} + \left[1 - \left(3Q_{1DG} + 3Q_{2DG} + Q_{3DG}\right)\right]\left[\left(P_{PF}\right)^3\right]$$
$$+ 2\left[Q_{1DG}\right]\left[\left(P_{PF}\right)^2\right] + \left[Q_{2DG}\right]\left[P_{PF}\right]$$

The resulting unavailability of fuel oil to diesel generator 21 under the boundary condition of offsite power not available is evaluated using discrete probability distribution arithmetic:

Mean: $Q_{F1} = 2.43 \times 10^{-5}$

Variance: 4.89×10^{-10}

The dominant contributor to fuel supply failure is the failure of the operators to restore power to the fuel transfer pump MCCs before all three fuel oil day tanks are drained.

1.5.2.2.1.4.4.1.2 Fuel contribution to unavailability of diesel generator 22. An examination of the contributors to fuel supply failure to diesel generator 22 under this boundary condition shows that the

failure states are completely symmetric with those described for diesel generator 21. Therefore, the unavailability of fuel to diesel generator 22 is equal to that quantified previously.

Mean: $Q_{F2} = 2.43 \times 10^{-5}$

Variance: 4.89×10^{-10}

1.5.2.2.1.4.4.1.3 Fuel contribution to unavailability of diesel generator 23. This case is also completely symmetric to that described for diesel generator 21. The unavailability of fuel to this diesel generator is:

Mean: $Q_{F3} = 2.43 \times 10^{-5}$

Variance: 4.89×10^{-10}

1.5.2.2.1.4.4.1.4 Fuel contribution to unavailability of diesel generators 21 and 22. If both diesel generators 21 and 22 have failed, their continued fuel supply is unnecessary. However, because of the interrelationships among the fuel oil transfer pump starting signals and power supplies, the contributions of individual failures of each of these diesel generators must be included in the quantification of the fuel supply unavailability to both. Therefore, failure of the fuel supply to these diesel generators will occur if:

- The operators fail to respond to reclose the MCC supply breakers.
- All three diesel generators are operating and all three fuel oil transfer pumps fail.
- Diesel generator 21 is unavailable and transfer pumps 22 and 23 fail. (Transfer pump 23 receives a starting signal, because diesel generator 23 is operating.)
- Diesel generator 22 is unavailable and transfer pumps 21 and 23 fail.
- Diesel generator 23 is unavailable and transfer pumps 21 and 22 fail.
- Diesel generators 21 and 23 are unavailable and transfer pump 22 fails.
- Diesel generators 22 and 23 are unavailable and transfer pump 21 fails.

All other possible states include the failure of both diesel generators 21 and 22 and, therefore, are not relevant to this analysis.

The total unavailability expression for the failure of fuel to these two diesel generators is

$$Q_{F12} = P_{NR} + \left[1 - \left(3Q_{1DG} + 3Q_{2DG} + Q_{3DG}\right)\right]\left[\left(P_{PF}\right)^3\right] + 3\left[Q_{1DG}\right]\left[\left(P_{PF}\right)^2\right] + 2\left[Q_{2DG}\right]\left[P_{PF}\right]$$

This equation is evaluated using discrete probability distribution arithmetic.

Mean: $Q_{F12} = 3.01 \times 10^{-5}$

Variance: 6.09×10^{-10}

The dominant contributors to fuel supply failure are failure of the operators to reenergize the transfer pump MCCs and the unavailability of diesel generators 21 and 23 or 22 and 23 with subsequent failure of the third transfer pump.

1.5.2.2.1.4.4.1.5 Fuel contribution to unavailability of diesel generators 21 and 23. The evaluation of the fuel unavailability to these two diesel generators is identical to that described above for diesel generators 21 and 22. Therefore, the resulting fuel unavailability distribution is:

Mean: $Q_{F13} = 3.01 \times 10^{-5}$

Variance: 6.09×10^{-10}

1.5.2.2.1.4.4.1.6 Fuel contribution to unavailability of diesel generators 22 and 23. This case is symmetric to the two preceding cases.

1.5.2.2.1.4.4.1.7 Fuel contribution to unavailability of all three diesel generators. Fuel will be unavailable to all three diesel generators if any of the following conditions occur:

- The operators fail to respond to reclose the MCC supply breakers.
- All three diesel generators are operating, and all three fuel transfer pumps fail.
- Any single diesel generator is unavailable, and the remaining two transfer pumps fail.
- Any combination of two diesel generators is unavailable, and the remaining single transfer pump fails.

If all three diesel generators have failed, all three transfer pumps will be deenergized, but there will be no need to transfer any fuel.

The fuel supply unavailability equation for this case is

$$Q_{F123} = P_{NR} + \left[1 - \left(3Q_{1DG} + 3Q_{2DG} + Q_{3DG}\right)\right]\left[\left(P_{PF}\right)^3\right] + 3\left[Q_{1DG}\right]\left[\left(P_{PF}\right)^2\right] + 3\left[Q_{2DG}\right]\left[P_{PF}\right]$$

The resulting unavailability of fuel is:

Mean: $Q_{F123} = 3.49 \times 10^{-5}$

Variance: 7.51×10^{-10}

The dominant contributors are the failure of the operators to restore power to the MCCs and the unavailability of a set of two diesel generators with subsequent failure of the third fuel transfer pump.

The following table summarizes the fuel supply failure contribution to the unavailability of the various combinations of diesel generators when offsite power is not available.

Unavailability Due to Fuel Supply Failure

Diesel Generator(s)	Mean	Variance	Dominant Contributor
21	2.43×10^{-5}	4.89×10^{-10}	(1)
22	2.43×10^{-5}	4.89×10^{-10}	(1)
23	2.43×10^{-5}	4.89×10^{-10}	(1)
21 and 22	3.01×10^{-5}	6.09×10^{-10}	(1),(2)
21 and 23	3.01×10^{-5}	6.09×10^{-10}	(1),(2)
22 and 23	3.01×10^{-5}	6.09×10^{-10}	(1),(2)
21, 22 and 23	3.49×10^{-5}	7.51×10^{-10}	(1),(2)

(1) Operator response
(2) Unavailability of two diesel generators

1.5.2.2.1.4.4.2 Fuel supply with offsite power available. The only signal which automatically loads the diesel generators onto their associated buses is undervoltage on either bus 5A or bus 6A following a generator trip or a safety injection. This "blackout" signal also trips the normal supply breakers to all four 480V buses and strips the feeds to MCCs 24, 27, and 29.

From the standpoint of diesel generator operation, these conditions are equivalent to those experienced as a result of the loss of offsite power. The availability of offsite power at the station auxiliary transformer affects the frequency at which voltage is initially lost at

any of the 480V buses. However, once the diesel generators are called on to automatically reenergize the buses, the unavailability of a sustained power supply is determined by the same factors considered in response to the loss of offsite power event. Therefore, the analysis of plant personnel response failures, diesel generator failures and unavailability, and fuel oil transfer system operation under these conditions is identical to that presented in Section 1.5.2.2.1.4.4.1. The fuel supply failure contributions to diesel generator unavailability summarized in Section 1.5.2.2.1.4.4.1 are also directly applicable to the quantification of power unavailability under the boundary condition of offsite power available.

1.5.2.2.1.4.5 System Failure State Quantification. The quantification of the nonmutually exclusive electric power system failure states is summarized in Tables 1.5.2.2.1-10A through 1.5.2.2.1-100 and 1.5.2.2.1-11A through 1.5.2.2.1-110. The basis for each table is an unavailability expression developed from the system failure state logic model which includes all component failure modes necessary and sufficient to achieve the given failure state. The distributions characterizing the individual component failure rates are combined through this equation using discrete probability distribution arithmetic to develop the hardware contribution to failure. Specifying unity failure rates for each diesel generator allows calculation of the conditional failure of power for various states of diesel generator unavailability. These conditional failure distributions are then combined with the probabilities that the diesel generators are in each of these unavailability states. This determines the contributions to each system failure state from diesel generator maintenance and fuel oil supply failure. The conditional failure distributions are also input to the quantification of common cause failures discussed in Section 1.5.2.2.1.4.6.

A detailed description of the methodology used in calculating the failure state summarized in Table 1.5.2.2.1-10A is presented in the following. The development of each of the other failure states is similar, and only a brief discussion of the applicable unavailability expression is included. The following variables are used in the development of the unavailability expressions:

Variable	Component Failure Mode
A	Bus failure (per hour)
B	Circuit breaker transfers open (per hour)
C	Transformer failure (per hour)
H	Diesel generator failure to start and load (per demand)
J	Circuit breaker failure to close (per demand)
L	DC control power failure (per hour)
M	Diesel generator failure during operation (per hour)

1.5.2.2.1.4.5.1 Boundary condition 1 (offsite power not availabile, no recovery from failures during 6-hour study period). Under this boundary condition, the only source of power to the 480V buses is from the diesel generators. All three diesel generators start automatically on loss of

voltage at any of the buses, and the diesel generator output breakers all receive an automatic signal to close as a result of the initial loss of voltage at buses 5A and 6A. The normal supply breakers to all of the 480V buses are also automatically opened by this signal. All motor control centers except MCCs 26A and 26B are automatically shed from the 480V buses.

1.5.2.2.1.4.5.1.1 Case 1: failure of power at bus 2A (Table 1.5.2.2.1-10A). Because diesel generator 22 provides the only source of power to bus 2A under these boundary conditions, failure of the diesel generator to start (H) or failure of its output breaker EG2A to close (J) will prevent bus 2A from being reenergized following the loss of offsite power. If the diesel generator starts and the breaker closes, then the diesel generator must maintain its power supply to the bus for 6 hours. Failures of the diesel generator (M), the breaker (B), or bus 2A (A) during this period will also result in a loss of bus voltage. A linear model for failures during the 6-hour period provides essentially the same results as an exponential model, and the uniform hourly failure rates are simply multiplied by the duration of the period. The unavailability expression for this failure state takes the form

$$Q_{2A} = H + J + [M(1 - H) + B(1 - J) + A]t$$

Although recovery from many of these failures is possible within the 6-hour study period, this analysis has been developed as a conservatively bounding input to the quantification of the dominant event sequence contributors to risk. The inclusion of these recovery actions and the assignment of their associated time dependent failure probability distributions will be undertaken in the context of specific dominant event sequences. These sequences define the actions that need to be taken and the time within which these actions must be accomplished to achieve overall plant recovery.

DC power failures are not included in the unavailability expression presented previously. Because the entire electric power system is assumed to be in its normal operating state immediately before event initiation, DC control power will be available to this division. The probability of losing DC power as a result of the event is negligible compared with the other component failure rates. Even if DC power is lost from one source, complete failure of control power to the diesel generator or switchgear requires the additional failure of either the redundant supply or the automatic control power transfer device. Once the diesel generator has started and its output breaker has closed, loss of DC power during the subsequent 6-hour period will not affect electric power system operation and, therefore, is not quantified.

The recovery of neither offsite power nor the diesel generator is allowed in this bounding analysis. Therefore, if diesel generator 22 is inoperable or otherwise unavailable for service when offsite power is lost, bus 2A will remain deenergized for the 6-hour study period. The conditional unavailability of power at bus 2A is 1.0 if diesel generator 22 is inoperable under the established boundary conditions.

To develop the maintenance contribution to the failure of power at bus 2A, the unavailability of diesel generator 22 due to maintenance is combined with the conditional failure of power at bus 2A, given that diesel generator 22 is unavailable. Because recovery is not included in the analysis, this latter value is unity, and the resulting distribution for the failure of power at bus 2A due to diesel generator maintenance is identical to the diesel generator unavailability distribution presented in Section 1.5.2.2.1.4.3.

Because the fuel oil transfer system will be called on to maintain operation of the diesel generator during the 6-hour period, the contribution to power failure at bus 2A from diesel fuel oil supply failures is identical to the fuel supply contribution to diesel generator 22 unavailability developed in Section 1.5.2.2.1.4.4.1.2.

1.5.2.2.1.4.5.1.2 Case 2: failure of power at bus 3A (Table 1.5.2.2.1-10B). This case is similar to Case 1.

1.5.2.2.1.4.5.1.3 Case 3: failure of power at bus 5A (Table 1.5.2.2.1-10C). This case is similar to Case 1.

1.5.2.2.1.4.5.1.4 Case 4: failure of power at bus 6A (Table 1.5.2.2.1-10D). This case is similar to Case 1.

1.5.2.2.1.4.5.1.5 Case 5: failure of power at buses 2A and 3A (Table 1.5.2.2.1-10E). Diesel generator 22 provides the only source of power to these buses under this boundary condition. Therefore, failure of this diesel generator to start or failure during the 6-hour study period will cause both buses to be deenergized. Because each bus is supplied through its own output breaker (EG2A and EG2B), both of these breakers must fail in order to interrupt the power supply from the diesel generator. The system analysis guidelines preclude efforts to recover power to either bus after a failure has occurred. Therefore, these breakers need not fail simultaneously to achieve this combined failure state. Any combination of failures of both breakers during the 6-hour study period will produce power failure at both buses. The unavailability expression for this failure state is

$$Q_{2A + 3A} = H + M(1 - H)t + \{J + [B(1 - J) + A]t\}^2$$

If diesel generator 22 is unavailable for service when offsite power is lost, both buses will remain deenergized. The conditional unavailability of power at these buses, given that diesel generator 22 is inoperable, is unity. The maintenance and fuel oil supply contributions to this failure state are identical to those discussed for case 1.

1.5.2.2.1.4.5.1.6 Case 6: failure of power at buses 2A and 5A (Table 1.5.2.2.1-10F). With offsite power lost, the failure of power at buses 2A and 5A requires component failures in the power supply trains from diesel generators 22 and 21, respectively. Because these diesel generators operate independently of each other, the unavailability

expressions for each of the two single bus power failure cases can be multiplied to produce the equation applicable to this combined failure state. This expression is

$$Q_{2A + 5A} = \{H\ J + [M(1 - H) + B(1 - J) + A]t\}^2$$

The system analysis guidelines preclude efforts to recover power to either bus after a failure has occurred. Therefore, failures need not be simultaneous to achieve this combined failure state. Any combination of failures of both diesel generator power supply trains with no recovery during the 6-hour study period will produce power failure at both buses.

If diesel generator 21 is unavailable for service, the conditional failure of power at buses 2A and 5A is determined by the failure of power at bus 2A alone. The failure distribution for this conditional state is identical to the distribution developed for the single state of failure of power at bus 2A. Similarly, if diesel generator 22 is unavailable, the conditional failure of power at buses 2A and 5A is determined by the failure of power at bus 5A. If both diesel generators are inoperable, both buses will remain deenergized when offsite power is lost.

To determine the maintenance contribution to the failure of power at buses 2A and 5A, the unavailablility of each diesel generator due to maintenance is multiplied by the corresponding conditional distribution for failure of power with that diesel generator unavailable. The resulting distributions are then summed. Because both diesel generators cannot be removed from service for maintenance at the same time during unit operation, simultaneous diesel generator maintenance does not contribute to the unavailability of power at buses 2A and 5A.

The fuel oil transfer system is common to both diesel generators. Because this analysis is extended for 6 hours following event initiation, failure of this system will cause failure of both diesel generators and will result in loss of power at both of these buses. The fuel supply contribution to this failure state is obtained by multiplying the conditional unavailability of power at both buses, given that both diesel generators are inoperable (unity), with the distribution developed in Section 1.5.2.2.1.4.4.1.4 for the unavailability of diesel generators 21 and 22 due to fuel supply failures.

1.5.2.2.1.4.5.1.7 Case 7: failure of power at buses 2A and 6A (Table 1.5.2.2.1-10G). This case is similar to Case 6.

1.5.2.2.1.4.5.1.8 Case 8: failure of power at buses 3A and 5A (Table 1.5.2.2.1.1-10H). This case is similar to Case 6.

1.5.2.2.1.4.5.1.9 Case 9: failure of power at buses 3A and 6A (Table 1.5.2.2.1-10I). This case is similar to Case 6.

1.5.2.2.1.4.5.1.10 Case 10: failure of power at buses 5A and 6A (Table 1.5.2.2.1-10J). This case is similar to Case 6.

1.5.2.2.1.4.5.1.11 Case 11: failure of power at buses 2A, 3A, and 5A (Table 1.5.2.2.1-10K). Because diesel generators 21 and 22 operate independently under these boundary conditions, the unavailability expression for this failure state is obtained by multiplying the expressions developed for the failure of power at buses 2A and 3A and the failure of power at bus 5A.

$$Q_{2A,\ 3A\ +\ 5A} = \{H + J + [M(1 - H) + B(1 - J) + A]t\}\ \{H + M\ (1 - H)t + [J + (B(1 - J) + A)\,t]^2\}$$

The maintenance and fuel supply contributions to power failure at these three buses are treated in the same manner as for the cases of power failure at two buses.

1.5.2.2.1.4.5.1.12 Case 12: failure of power at buses 2A, 3A, and 6A (Table 1.5.2.2.1-10L). This case is similar to Case 11.

1.5.2.2.1.4.5.1.13 Case 13: failure of power at buses 2A, 5A and 6A (Table 1.5.2.2.1-10M). This failure state requires failures in the power supply trains from all three diesel generators. The unavailability expression for this state is

$$Q_{2A,\ 5A\ +\ 6A} = \{H + J + [M(1 - H) + B(1 - J) + A]t\}^3$$

Although failure of diesel generator 22 will cause a loss of power at buses 2A and 3A, this expression defines the failure combinations which are necessary and sufficient to achieve the given nonmutually exclusive failure state. The application of Boolean logic to the entire set of nonmutually exclusive states will eliminate higher order failure influences from each mutually exclusive state. (Refer to Section 1.5.2.2.1.3.2 for a discussion of mutually and nonmutually exclusive failure states.)

Because recovery actions are not included in this analysis, it should be emphasized that this failure state is achieved if each of the three diesel generator divisions experiences a failure at any time during the 6-hour analysis period (i.e., once power has been lost to a specific bus, it remains deenergized for the entire period). The conditional unavailability of power at these buses with each combination of diesel generators inoperable is obtained directly from the reduced system failure state caused by that condition. (For example, with diesel generators 21 and 22 inoperable, power will be failed at buses 2A and 5A. The conditional unavailability of power at all three buses with these two diesel generators inoperable is identical to the distribution for failure of power at bus 6A alone.)

The maintenance contribution to power unavailability is obtained by summing the effects from each of the three diesel generators. This

value is calculated for each diesel generator from the product of diesel generator unavailability due to maintenance (from Section 1.5.2.2.1.4.3) and the conditional power unavailability with that diesel generator inoperable.

Fuel transfer system failures cause all three diesel generators to fail. The contribution to power unavailability from this cause is obtained from the product of the unavailability of all three diesel generators due to fuel supply failures (from Section 1.5.2.2.1.4.4.1.7) and the unavailability of power at these buses with all three diesel generators failed (unity).

1.5.2.2.1.4.5.1.14 Case 14: failure of power at buses 3A, 5A, and 6A (Table 1.5.2.2.1-10N). This case is similar to Case 13.

1.5.2.2.1.4.5.1.15 Case 15: failure of power at all 480V buses (Table 1.5.2.2.1-100). The unavailability expression for the failure of power at all four 480V buses is similar to that developed for Cases 13 and 14, except that failures of both output breakers from diesel generator 22 and failures of buses 2A and 3A are included.

$$Q_{2A,\ 3A,\ 5A\ +\ 6A} = \{H + M(1 - H)t + [J + (B(1 - J) + A)t]^2\}$$
$$\times \{H + J + [M(1 - H) + B(1 - J) + A]t\}^2$$

The maintenance and fuel supply contributions to this failure state are quantified in the same manner as for Case 13.

1.5.2.2.1.4.5.2 Boundary condition 2 (offsite power available, no recovery from failure during 6-hour study period). Under this boundary condition, the 480V buses should remain energized from the offsite power source. When the unit trip occurs, the supplies to 480V buses 2A and 3A (from 6.9 kV buses 2 and 3) are automatically transferred to the station auxiliary transformer. Buses 5A and 6A remain energized through their normal offsite power supply paths (from 6.9 kV buses 5 and 6). No motor control centers are automatically shed from the buses.

If an undervoltage condition is detected at any of the 480V buses, an automatic signal to start all three diesel generators is initiated. However, under these boundary conditions, the diesel generator output breakers will automatically close only if an undervoltage condition is detected at bus 5A or bus 6A (normally indicative of offsite power failure). This undervoltage signal also opens the normal supply breakers to all of the 480V buses and sheds all motor control centers except MCCs 26A and 26B. Therefore, for any cases which do not affect power at bus 5A or bus 6A, the diesel generators will receive starting signals but will run unloaded until the operator takes manual action to load them onto the deenergized bus (or buses). As discussed previously, the quantification presented in this section does not include operator recovery considerations. This is because of their strong dependence on the allowable recovery time for the specific scenario analyzed and because the operator's actions will drastically modify the operating

characteristics of the system hardware. The unavailability calculated for each of these failure states is a conservative upper bound which may be reduced through operator intervention. (These recoverability factors are discussed further in Section 1.5.2.2.1.4.9.)

1.5.2.2.1.4.5.2.1 Case 1: failure of power at bus 2A (Table 1.5.2.2.1-11A). If the normal power supply to bus 2A is lost as a result of failures of breaker UT2/ST5 (either failure to transfer or spurious failure following transfer), 6.9 kV bus 2, breaker SS2, station service transformer 2, or breaker 2A (refer to Figure 1.5.2.2.1-3 for component designations), diesel generator 22 will automatically start but will run unloaded until the operator closes its output breaker to the bus. Because manual operator actions are excluded from this boundary analysis, any of these failures will result in bus 2A remaining deenergized for the study period. The contribution to power failure at bus 2A from these failures is identified by the term

$$J + [A + 2B + B(1 - J) + C]t$$

in the unavailability expression presented in the following.

If voltage is lost at bus 5A or bus 6A because of failures involving the normal power supply paths to these buses, the normal power supply to bus 2A will also be automatically deenergized (breaker 2A receives a trip signal) and diesel generator 22 will be automatically loaded onto the bus. Therefore, failures of the following components will affect the normal source of power to bus 2A and are included in this analysis (refer to Figure 1.5.2.2.1-3 for component designations):

- Failure of the station auxiliary transformer.
- Breaker ST5 or ST6 transfers open.
- Failure of 6.9 kV bus 5 or bus 6.
- Breaker SS5, SS6, 5A or 6A transfers open.
- Failure of station service transformer 5 or 6.
- Failure of bus 5A or bus 6A.

The factor in unavailiability expression which quantifies these contributions is

$$\{Ct + 2[2A + 3B + C]t\}$$

Following any of these failures involving bus 5A or bus 6A, diesel generator 22 receives an automatic signal to reenergize bus 2A. Failures of the diesel generator or breaker EG2A will cause subsequent power loss at bus 2A. The bus will also remain deenergized if DC control power has failed at the diesel generator or at the 480V switchgear during the period between event initiation and loss of voltage at bus 5A or bus 6A. The factor in the unavailability expression which quantifies these diesel generator power train failures is

$$\{H + J + [M(1 - H) + B(1 - J) + L]t\}$$

Although specific sequential failures are required in this scenario (i.e., the diesel generator is required to operate only after power has been lost at bus 5A or bus 6A), the modeling of these failures is simplified by including component failures over the full 6-hour period. This introduces additional conservatism into the results because the diesel generator may not need to operate for 6 hours. However, these effects are minor and conservative. The failure of DC control power is represented by a single variable (L) in the unavailability expression. The value assigned to this variable includes the failures of the normal and reserve supplies of control power and, in all cases of interest in this analysis, is very small compared with the failure rates for the diesel generator and its output breaker.

In addition to the failures discussed in the preceding, bus 2A may fail at any time during the 6-hour study period. This contribution to power failure is represented by the term "At." The complete unavailability expression for the failure of power at bus 2A under this boundary condition is

$$Q_{2A} = J + [2A + 2B + B(1 - J) + C]t + \{Ct + 2[2A + 3B + C]t\}$$

$$\times \{H + J + [M(1 - H) + B(1 - J) + L]t\}$$

If diesel generator 22 is unavailable for service, bus 2A will remain deenergized following any failure in the normal power supply paths to bus 2A, bus 5A or bus 6A. The conditional unavailability expression for the loss of power at bus 2A, given that diesel generator 22 is inoperable, is

$$Q_{2A,\ \overline{DG}} = J + [2A + 2B + B(1 - J) + C]t + \{Ct + 2[2A + 3B + C]t\}$$

The maintenance contribution to power failure is obtained by multiplying this conditional power availability distribution by the distribution presented in Section 1.5.2.2.1.4.3 for the unavailability of diesel generator 22 due to maintenance. Similarly, the fuel supply contribution to power failure is obtained by combining the conditional power unavailability distribution with the distribution for diesel generator 22 unavailability due to fuel failures developed in Section 1.5.2.2.1.4.4.2.

1.5.2.2.1.4.5.2.2 Case 2: failure of power at bus 3A (Table 1.5.2.2.1-11B). This case is similar to Case 1.

1.5.2.2.1.4.5.2.3 Case 3: failure of power at bus 5A (Table 1.5.2.2.1-11C). Following a unit trip, an undervoltage condition at bus 5A or bus 6A will cause breaker 5A to be tripped and diesel generator 21 to be automatically loaded onto bus 5A. Because the diesel generator output breaker receives an automatic closing signal whenever voltage is lost at bus 5A, failure of power at this bus requires failure of any component in the normal power supply train to bus 5A or bus 6A and subsequent failure of the power supply from diesel generator 21. The unavailability expression for this failure state is

$$Q_{5A} = At + [(3A + 6B + 3C)t]\{H + J + [M(1 - H) + B(1 - J) + L]t\}$$

If the diesel generator is unavailable for service, bus 5A will remain deenergized following any of the normal power supply path failures discussed above. The expression for the conditional unavailability of power at bus 5A with diesel generator 21 inoperable is

$$Q_{5A,\ \overline{DG}} = At + (3A + 6B + 3C)t$$

As described previously, the maintenance and fuel supply failure contributions to this case are obtained by multiplying this conditional power failure distribution by the distributions from Sections 1.5.2.2.1.4.3 and 1.5.2.2.1.4.4.2 for diesel generator 21 unavailabilty due to these causes.

1.5.2.2.1.4.5.2.4 Case 4: failure of power at bus 6A (Table 1.5.2.2.1-11D). This case is similar to Case 3.

1.5.2.2.1.4.5.2.5 Case 5: failure of power at buses 2A and 3A (Table 1.5.2.2.1-11E). Combinations of failures of the following components in each bus power supply path will result in both buses 2A and 3A being deenergized with no signal for automatic closure of diesel generator 22 output breakers EG2A or EG2B (refer to Figure 1.5.2.2.1-3 for component designations).

- Breakers UT2/ST5 and UT3/ST6 (failure to transfer or spurious failure following transfer).
- 6.9 kV bus 2 and bus 3.
- Breakers SS2, SS3, 2A and 3A.
- Station service transformers 2 and 3.
- Bus 2A and bus 3A.

Because no manual operator actions are considered in this analysis, buses 2A and 3A will remain deenergized if these normal power supplies fail. The contribution of these failures to the unavailability of power at these buses is quantified by the term

$$\{At + [J + (A + 2B + B(1 - J) + C)t]\}^2$$

An undervoltage condition at bus 5A or bus 6A will automatically trip the normal supply breakers to buses 2A and 3A. Therefore, any component failure in the normal power supply path to bus 5A or bus 6A will also cause failure of the normal power supply to buses 2A and 3A. However, in this situation diesel generator 22 is automatically loaded onto these buses. Complete failure of power at both buses requires the additional failure of the diesel generator, both diesel generator output breakers, or the normal and reserve sources of DC control power.

The complete unavailability expression for the failure of power at buses 2A and 3A is

$$Q_{2A + 3A} = \{At + [J + (A + 2B + B(1 - J) + C)t]\}^2 + \{Ct + 2[2A + 3B + C]t\}\{H + [M(1 - H) + L]t + [J + B(1 - J)t]^2\}$$

If diesel generator 22 is inoperable, power will be lost at both buses as a result of the combined failures of the supply paths from 6.9 kV buses 5 and 6 to these buses or as a result of any single failure in the normal power supply path to bus 5A or bus 6A. The expression for the conditional unavailability of power at buses 2A and 3A with diesel generator 22 inoperable is

$$Q_{2A + 3A, \overline{DG}} = \{At + [J + (A + 2B + B(1 - J) + C)t]\}^2 + \{Ct + 2[2A + 3B + C]t\}$$

The calculation of the maintenance and fuel supply contributions to power failure uses this conditional failure distribution as discussed in the preceding cases.

1.5.2.2.1.4.5.2.6 Case 6: failure of power at buses 2A and 5A (Table 1.5.2.2.1-11F). Failure of power at both of these buses will occur if any of the following conditions are satisfied:

- Buses 2A and 5A fail.
- The normal power supply to bus 5A or bus 6A fails, the power supply to bus 5A from diesel generator 21 fails, and bus 2A fails.
- Bus 5A fails, and the power supply to bus 2A from diesel generator 22 fails (breaker 2A is automatically tripped when bus 5A fails).
- The normal power supply to bus 5A or bus 6A fails, and the power supplies to buses 2A and 5A from diesel generators 21 and 22 fail.

The unavailability expression derived from these four failure conditions is

$$Q_{2A + 5A} = (At)^2 + [(3A + 6B + 3C)t](At)\{H + J + [M(1 - H) + B(1 - J) + L]t\} + (At)\{H + J + [M(1 - H) + B(1 - J) + L]t\} + [(3A + 6B + 3C)t] \times \{H + J + [M(1 - H) + B(1 - J) + L]t\}^2$$

Any failure which causes only bus 2A to be deenergized will not affect the power supply to bus 5A. However, any failure which causes a loss of power at bus 5A will also trip the normal power supply to bus 2A. Therefore, failures involving components unique to the normal power supply path to bus 2A are irrelevant to the achievement of this combined bus failure state. (Examples are failures of breaker UT2/ST5, station service transformer 2, etc.)

If diesel generator 21 is inoperable, the conditional failure of power at buses 2A and 5A is determined through evaluation of the expression

$$Q_{2A + 5A, \overline{DG21}} = (At)^2 + [(3A + 6B + 3C)t](At) + (At)\{H + J + [M(1 - H) + B(1 - J) + L]t\} + [(3A + 6B + 3C)t] \times \{H + J + [M(1 - H) + B(1 - J) + L]t\}$$

Similarly, if diesel generator 22 is inoperable

$$Q_{2A + 5A, \overline{DG22}} = (At)^2 + [(3A + 6B + 3C)t](At)\{H + J\ [M(1 - H) + B(1 - J) + L]t\} + (At) + [(3A + 6B + 3C)t]\{H + J + [M(1 - H) + B(1 - J) + L]t\}$$

If both diesel generators are unavailable, power will be lost at both of these buses if both buses fail, if only bus 5A fails, or if any component fails in the normal power supply path to bus 5A or bus 6A.

$$Q_{2A + 5A, \overline{DG22 + 21}} = (At)^2 + (At) + (3A + 6B + 3C)t$$

The maintenance contribution to this failure state is calculated by combining the unavailability of each diesel generator due to maintenance with the corresponding conditional power failure distribution. Because either diesel generator may be out of service for maintenance when the initiating event occurs, these individual diesel generator effects are added to produce the total maintenance contribution.

Failure of the fuel oil transfer system will result in failure of both diesel generators. Because both diesel generators will automatically start and load under any condition involving loss of voltage at bus 5A, the contribution to this failure state from diesel fuel oil supply failures is obtained by multiplying the conditional power unavailability distribution developed previously with both diesel generators inoperable by the distribution presented in Section 1.5.2.2.1.4.4.2 for the unavailability of diesel generators 21 and 22 due to fuel supply failures.

1.5.2.2.1.4.5.2.7 Case 7: failure of power at buses 2A and 6A (Table 1.5.2.2.1-11G). This case is similar to Case 6.

1.5.2.2.1.4.5.2.8 Case 8: failure of power at buses 3A and 5A (Table 1.5.2.2.1-11H). This case is similar to Case 7.

1.5.2.2.1.4.5.2.9 Case 9: failure of power at buses 3A and 6A (Table 1.5.2.2.1-11I). This case is similar to Case 6.

1.5.2.2.1.4.5.2.10 Case 10: failure of power at buses 5A and 6A (Table 1.5.2.2.1-11J). Because an undervoltage condition at either of these buses trips the normal power supply breakers to both buses, any of the following conditions will result in this failure state:

- Buses 5A and 6A fail.
- Bus 5A fails, and the power supply to bus 6A from diesel generator 23 fails.
- Bus 6A fails, and the power supply to bus 5A from diesel generator 21 fails.
- The normal power supply to either bus fails, and the power supplies to both buses from diesel generators 21 and 23 fail.

The unavailability expression corresponding to these failures conditions is

$$Q_{5A + 6A} = (At)^2 + 2(At)\{H + J + [M(1 - H) + B(1 - J) + L]t\} + [(2A + 6B + 3C)t]\{H + J + [M(1 - H) + B(1 - J) + L]t\}^2$$

If diesel generator 21 or diesel generator 23 is inoperable, the condition failure of power at buses 5A and 6A is determined by the expression

$$Q_{5A + 6A, \overline{DG}} = (At)^2 + (At) + (At)\{H + J + [M(1 - H) + B(1 - J) + L]t\} + [(2A + 6B + 3C)t]\{H + J + [M(1 - H) + B(1 - J) + L]t\}$$

If both diesel generators are unavailable for service, the conditional failure state is characterized by

$$Q_{5A + 6A, \overline{DG21 + 23}} = (At)^2 + 2(At) + [(2A + 6B + 3C)t]$$

Maintenance and fuel supply failure contributions to this failure state are evaluated in the same manner as in the preceding cases.

1.5.2.2.1.4.5.2.11 Case 11: failure of power at buses 2A, 3A and 5A (Table 1.5.2.2.1-11K). The methodology used in the analysis of this failure state is identical to that described for the preceding cases under this boundary condition. Failure of power at all three of these buses will occur if any of the following criteria are satisfied:

- Buses 2A, 3A, and 5A fail.
- Buses 2A and 3A fail, and the normal power supply to bus 5A or bus 6A fails, and the power supply to bus 5A from diesel generator 21 fails.
- Buses 2A and 5A (3A and 5A) fail, and the power supply to bus 3A (2A) from diesel generator 22 fails.
- Bus 2A (3A) fails, the normal power supply to bus 5A or bus 6A fails, and the power supply to buses 3A and 5A (2A and 5A) from diesel generators 21 and 22 fail.
- Bus 5A fails, and the power supply to buses 2A and 3A from diesel generator 22 fails.
- The normal power supply to bus 5A or bus 6A fails, and the power supplies from diesel generators 21 and 22 fail.

The unavailability expression corresponding to these failures conditions is the following:

$$
\begin{aligned}
Q_{2A,\ 3A\ +\ 5A} = {} & (At)^3 + (At)^2[(3A + 6B + 3C)t]\{H + J + [M(1 - H) \\
& + B(1 - J) + L]t\} + 2(At)^2\{H + J + [M(1 - H) \\
& + B(1 - J) + L]t\} + 2(At)\{H + J + [M(1 - H) + B(1 - J) \\
& + L]t\}^2 + (At)\{H + [M(1 - H) + L]t \\
& + [J + B(1 - J)t]^2\} + [(3A + 6B + 3C)t]\{H + J \\
& + [M(1 - H) + B(1 - J) + L]t\}\ \{H + [M(1 - H) + L]t \\
& + [J + B(1 - J)t]^2\}
\end{aligned}
$$

No failures of components unique to the normal power supply paths to buses 2A and 3A are included in this analysis. The failure of at least one component in the normal power supply path to bus 5A or bus 6A is required to achieve the given failure state. The resulting undervoltage condition at bus 5A or bus 6A will trip the normal power supplies to buses 2A and 3A regardless of their status.

The derivations of the conditional power unavailability expressions with diesel generator 21 inoperable, diesel generator 22 inoperable, and with

both diesel generators unavailable for service are analogous to those presented in each of the preceding cases. These conditional equations are:

$$Q_{2A,\ 3A+5A,\ \overline{DG21}} = (At)^3 + 2(At)^2\{H + J + [M(1 - H) + B(1 - J) + L]t\} + (At)^2[(3A + 6B + 3C)t] + 2(At)[(3A + 6B + 3C)t]\{H + J + [M(1 - H) + B(1 - J) + L]t\} + (At)\{H + [M(1 - H) + L]t + [J + B(1 - J)t]^2\} + [(3A + 6B + 3C)t] \times \{H + [M(1 - H) + L]t + [J + B(1 - J)t]^2\}$$

$$Q_{2A,\ 3A+5A,\ \overline{DG22}} = (At)^3 + 2(At)^2 + (At)^2[(3A + 6B + 3C)t] \times \{H + J + [M(1 - H) + B(1 - J) + L]t\} + 2(At)[(3A + 6B + 3C)t]\{H + J + [M(1 - H) + B(1 - J) + L]t\} + (At) + [(3A + 6B + 3C)t] \times \{H + J + [M(1 - H) + B(1 - J) + L]t\}$$

$$Q_{2A,\ 3A+5A,\ \overline{DG21+22}} = (At)^3 + 2(At)^2 + (At) + 2(At) \times [(3A + 6B + 3C)t] + (3A + 6B + 3C)t$$

1.5.2.2.1.4.5.2.12 Case 12: failure of power at buses 2A, 3A and 6A (Table 1.5.2.2.1-11L). This case is similar to Case 11.

1.5.2.2.1.4.5.2.13 Case 13: failure of Power at Buses 2A, 5A and 6A (Table 1.5.2.2.1-11M). The failure of power at buses 2A, 5A and 6A will occur if:

- Buses 2A, 5A and 6A fail.
- Two of the buses fail, and the power supply from the diesel generator to the remaining bus fails.
- Bus 5A (6A) fails, and the power supplies from diesel generators 22 and 23 (21) fail.
- Bus 2A fails, the normal power supply to bus 5A or bus 6A fails, and the power supplies from diesel generators 21 and 23 fail.
- The normal power supply to bus 5A or bus 6A fails, and the power supplies from all three diesel generators fail.

The unavailability expression for this failure state is:

$$Q_{2A,\ 5A + 6A} = (At)^3 + 3(At)^2\{H + J + [M(1 - H) + B(1 - J) + L]t\} + 2(At)\{H + J + [M(1 - H) + B(1 - J) + L]t\}^2 + [(2A + 6B + 3C)t](At)\{H + J + [M(1 - H) + B(1 - J) + L]t\}^2 + [(2A + 6B + 3C)t]\{H + J + [M(1 - H) + B(1 - J) + L]t\}^3$$

Some of the failures described here may also cause the failure of power at bus 3A. However, the given unavailability expression has been derived for the set of failure conditions which are necessary and sufficient for the achievement of this nonmutually exclusive failure state. Section 1.5.2.2.1.3.2 discusses the application of Boolean logic to determine the mutually exclusive failure states from the complete set of nonmutually exclusive states.

The conditional failure of power at all three of these buses with each combination of diesel generators unavailable is computed by selectively removing the inoperable diesel generator(s) from the given unavailability expression and by evaluating the resulting reduced equation. The maintenance contribution to power failure is obtained by multiplying the distributions for individual diesel generator unavailability due to maintenance (from Section 1.5.2.2.1.4.3) by the corresponding conditional power failure distributions. Because any of the diesel generators may be out of service for maintenance when the initiating event occurs, these three individual diesel generator maintenance inputs are added to produce the total contribution to power failure due to maintenance. Similarly, the distribution presented in Section 1.5.2.2.1.4.4.2 for the unavailability of all three diesel generators due to fuel supply failures is multiplied by the conditional power failure distribution with all three diesel generators inoperable to produce the fuel supply failure contribution to this power failure state.

1.5.2.2.1.4.5.2.14 Case 14: failure of power at buses 3A, 5A and 6A (Table 1.5.2.2.1-11N). This case is similar to Case 13.

1.5.2.2.1.4.5.2.15 Case 15: failure of power at all 480V buses (Table 1.5.2.2.1-110). The derivation of the unavailability expression for this failure state is an extension of the process outlined in the preceding cases. As discussed, failures of components in the normal power supply paths from 6.9 kV buses 5 and 6 to buses 2A and 3A are not included in this analysis, because any failure involving the normal power supply to bus 5A or bus 6A will automatically trip the normal

supply breakers to all four buses. The unavailability expression for the failure of power at all four 480V buses with offsite power available is:

$$
\begin{aligned}
Q_{2A,\ 3A,\ 5A,\ 6A} = {} & (At)^4 + 4(At)^3 \{H + J + [M(1 - H) + B(1 - J) \\
& + L]t\} + 4(At)^2 \{H + J + [M(1 - H) + B(1 - J) \\
& + L]t\}^2 + (At)^2 [(2A + 6B + 3C)t] \{H + J \\
& + [M(1 - H) + B(1 - J) + L]t\}^2 + (At)^2 \\
& \times \{H + [M(1 - H) + L]t + [J + B(1 - J)t]^2\} \\
& + 2(At) [(2A + 6B + 3C)t] \{H + J + [M(1 - H) \\
& + B(1 - J) + L]t\}^3 + 2(At) \{H + J + [M(1 - H) \\
& + B(1 - J) + L]t\} \{H + [M(1 - H) + L]t \\
& + [J + B(1 - J)t]^2\} + [(2A + 6B + 3C)t] \\
& \times \{H + J + [M(1 - H) + B(1 - J) + L]t^2\} \\
& \times \{H + [M(1 - H) + L]t + [J + B(1 - J)t]^2\}
\end{aligned}
$$

As in all of the cases analyzed under this boundary condition, failures of any of the components in the electric power system are conservatively allowed to occur at any time during the 6-hour period of this study. No attempt is made to model the time sequencing of the various combined failures required to achieve this failure state, and no recovery of failed components is considered.

The maintenance and fuel supply failure contribution to power unavailability are quantified in the same manner as described in the preceding cases.

1.5.2.2.1.4.6 Common Cause Failures. A number of common causes have been identified as potential contributors to failure of the electric power system at Indian Point Unit 2. The susceptibility of the system to failures induced by these causes generally depends on: the locations of the system components, the physical properties of these components, the operating characteristics of the components as they are integrated into the power system design, and the manner in which the system is operated, maintained, and tested by plant personnel.

1.5.2.2.1.4.6.1 External events. Electrical power supply equipment is generally susceptible to failures induced by high temperature, moisture, vibration or impact, and grit or dirt. Switchgear and cable fires can affect the operation of many plant safeguards systems. Because of their pervasive nature, these fires are treated separately in this study as a generic failure cause applicable to all systems. Fires in the Indian Point Unit 2 diesel generator building present a potential hazard to all three diesel generators, and their treatment is also included in

the fire analysis section of the main study report. The generic category of plant system failures caused by seismic events is also treated separately in this study.

The only portions of the electric power system subject to conditions in which significant moisture or flooding could be present are the electrical cable tunnel and the containment penetration area. In the cable tunnel, all cables are fully insulated and are routed in cable trays supported above floor level. There is a floor drain system and ventilation fans maintain sufficient air circulation to reduce the latent moisture to a level below which cable degradation could be expected. To disable any portion of the electric power system, a flood in this area would have to be of sufficient magnitude and duration to submerge at least the lower cable trays. Under these extreme conditions, it is expected that many plant systems and components located at lower elevations would be affected more severely than the cabling. Even if submerged, water could affect the cables only through insulation faults, and these faults would have to result in a very selected set of consequences to produce any significant damage to the power system. (For example, because the power supply cables to the switchgear buses are not routed in the cable tunnel, the flood-induced faults would have to be of such a nature as to defeat the normal overcurrent fault protection devices which would open the affected load circuits at their switchgear supply breakers.) Moisture which could be present in the containment cable penetration area (from pipe ruptures, minor leakage, condensation, etc.) could similarly affect single component power supply circuits through selected insulation faults, but is very unlikely to result in damage to the power supply switchgear due to the operation of the fault protection devices.

Diesel engine failures which result in the ejection of large missiles are extremely rare events. Although there is no substantial shielding between the diesel generators to prevent these objects from impacting upon the adjacent units, the missile would have to be of sufficient energy to sever a control, lubrication, or fuel line before severe damage to the operability of a second unit would occur. In such cases, immediate unit shutdown would be required by the plant technical specifications, because more than one diesel generator would be inoperable. The probability of the occurrence of an independent initiating event requiring the operation of all three diesel generators in coincidence with this type of failure is negligible when compared with other causes which could affect the diesels. The only other location in which the electric power system exhibits a potential susceptibility to impact damage is the 480V switchgear room located in the control building. The instrument air compressor located in this room is a low pressure reciprocating unit which is not subject to failures which would result in the ejection of high energy missiles. Even if such a failure were to occur, the compressor is oriented so that the most probable trajectory for the resulting low energy missiles is away from the switchgear. The switchgear buswork is mounted in steel enclosures which provide additional protection of the energized sections from impact damage.

None of the electric power system equipment is located in areas of the plant that are subject to significant dust, dirt, or grit. Individual component failures resulting from conditions such as dirty contacts, relay plunger binding, control line clogging, etc., which are the result of this general cause category, have been included in the quantification of the plant specific hardware failure data in Section 1.5.1 of this report.

1.5.2.2.1.4.6.2 Human error. Personnel errors associated with the periodic testing of the diesel generators are included in the testing contribution to power failure for each operability state. In Section 1.5.2.2.1.4.2 it is noted that the diesel generator operating mode selector switches are annunciated at the Unit 2 control panels if they are placed in any position other than "Auto." Therefore, the inoperability of a diesel generator due to a mispositioned switch requires errors by the testing personnel and by the control room operators. These errors are discussed in greater detail and are quantified in Section 1.5.2.2.1.4.2.

Operator failures to reenergize the motor control centers that supply vital diesel generator auxiliaries following automatic load shedding sequences are included in the quantification of failure of the diesel fuel oil supply presented in Section 1.5.2.2.1.4.4.

The diesel generators are the only major components of the electric power system which are subject to frequent maintenance during unit operation. Errors made by maintenance personnel during the disassembly, inspection, repair, and reassembly of the diesel engine, generator, or of any portion of their control or support systems could result in subsequent failure of the diesel generator. The section on human error rates in the methodology section of the main study report provides the following lognormal distribution for the frequency of errors by maintenance personnel:

Mean: 9.0×10^{-3} error/maintenance event

Variance: 1.8×10^{-4}

Not all of the errors committed during maintenance have the same potential for causing total failure of the diesel generator. In fact, it is expected that most of the errors will have a relatively minor impacts on the successful operation of the unit. However, it must also be recognized that any error results in a measurable level of degradation. Because very little information is available regarding the long term operational effects of minor errors, it is conservatively assumed in this analysis that any error, regardless of its precise nature, could lead to failure of the diesel generator.

Each diesel generator must be tested to verify its operability following maintenance. Because the successful completion of this testing requires that the diesel generator start, accept the load, and operate under load for some period of time without exceeding established operating parameter limits, most maintenance personnel errors affecting diesel

generator operability will be detected before the diesel generators are returned to service. A conservative estimate of 95% for the effectiveness of the diesel generator testing program is used for detecting these errors. The resulting frequency of undetected maintenance errors is:

Mean: 4.50×10^{-4} undetected error/maintenance event

Variance: 4.50×10^{-7}

Because normal diesel generator testing will not identify these errors, they would remain in effect for the entire period between successive maintenance events. Because the frequency of maintenance and the mean duration between maintenance events are reciprocal quantities, the distribution developed for the error frequency per maintenance event is numerically equal to the distribution for the unavailability of each diesel generator due to these undetected errors:

Mean: $Q_{ME1} = 4.50 \times 10^{-4}$

Variance: 4.50×10^{-7}

All the diesel generators are serviced by the same plant maintenance staff and are subject to the same testing procedures. A review of the plant's maintenance records indicates that the actual work performed during individual maintenance events varies significantly in terms of the scope and the specific components affected. Except for the major overhaul and inspection of each unit that is performed once during each refueling cycle, there is no significant evidence of maintenance trends in which the same work is performed on each of the diesel generators in succession. Therefore, only a weak coupling is considered to exist between errors made during the repair of one diesel generator and those made during work on the other units. The section on human error rates in the methodolody section of the main report provides an analytical expression which models this low dependence between errors made during task N and the error rate for the preceding task N-1,

$$\gamma_N = \frac{1 + 19\,\gamma_{N-1}}{20}$$

The development and application of this relation are discussed in the methodology section. It is used in this analysis to quantify the coupling between the medians of the error frequency distributions for maintenance events. As discussed in the development of this expression, an error factor of 5 is assigned to the resulting distribution for γ_N to express the uncertainty about this relation. The median of the lognormal distribution for undetected errors on single diesel generators is $\gamma_{N-1} = 2.50 \times 10^{-4}$. Use of this value in the low dependence coupling expression and application of the error factor results in the following distribution for the frequency of undetected errors on a second

diesel generator, given an error has been committed during maintenance of the first unit:

Median: 5.02×10^{-2} error/second event, given an initial error

Mean: 8.10×10^{-2} error/second event, given an initial error

Variance: 1.05×10^{-2}

The unavailability of both diesel generators due to these weakly coupled errors is determined by multiplying the conditional unavailability distribution for the second diesel generator by the distribution for error produced unavailability of the first unit. The resulting distribution for the unavailability of two diesel generators due to undetected maintenance errors is:

Mean: $Q_{ME2} = 3.65 \times 10^{-5}$

Variance: 4.73×10^{-9}

Given that errors have occurred during the maintenance of two diesel generators, application of the weak coupling expression to determine the conditional error frequency for a third diesel generator results in the following distribution for the unavailability of three diesel generators due to undetected maintenance errors:

Mean: $Q_{ME3} = 2.95 \times 10^{-6}$

Variance: 4.92×10^{-11}

The net effect of these maintenance errors is the possibility that one, two, or all three diesel generators may be unavailable for service due to some undetected flaw which will cause failure of the diesel generator during starting or subsequent operation. Each of the electric power system failure states developed in Section 1.5.2.2.1.4.5 includes distributions for the conditional unavailability of power for various combinations of diesel generator unavailability. The contribution to power failure from undetected maintenance errors is obtained by combining the conditional power failure distributions with the corresponding diesel generator unavailability distributions presented previously. The process is analogous to that described previously for quantifying the effects of fuel supply failures. Mathematically, the contribution to power failure from diesel generator maintenance errors (Q_{HE}) is obtained through evaluation of the following general expression:

Q_{HE} = [Q_{ME1} x Σ (conditional unavailability of power with each single diesel generator inoperable)]

+ [Q_{ME2} x Σ (conditional unavailability of power with each set of two diesel generators inoperable)]

+ [Q_{ME3} x Σ (conditional unavailability of power with all three diesel generators inoperable)].

The results of this combination process are presented in the system failure state summary Tables 1.5.2.2.1-12A and 1.5.2.2.1-12B, which are discussed more fully in Section 1.5.2.2.1.4.7.

The only other significant human error contribution to failure of the electric power system is associated with the recovery of portions of the system which are deenergized by other independent failures following event initiation. As discussed previously, to develop a conservative set of bounding failure probabilities for use in each of the event sequences considered in this study, the operator recovery error rate is taken to be unity over the 6-hour period following event initiation. For those event sequences in which the failure of electric power under these boundary conditions is a major contributor to overall plant nonrecoverability, the time dependent operator interactions with the electric power system will be quantified in the specific context of the applicable accident scenario.

1.5.2.2.1.4.6.3 System design. The most significant design related contributors to failure of the electric power system are:

- The automatic opening of all 480V normal bus power supply breakers and loading of the diesel generators onto all buses conditional upon a selected set of undervoltage conditions at only two of the buses. (The effects of this diesel generator loading logic are described and quantified in each of the system failure states presented in Section 1.5.2.2.1.4.5.2.)

- The automatic stripping of the motor control centers supplying power to the diesel fuel oil transfer pumps under indications of loss of offsite power. (This contribution is quantified in the fuel oil supply failure analysis presented in Section 1.5.2.2.1.4.4.)

1.5.2.2.1.4.6.4 Other failure cause contributors. It is possible that other factors not explicitly identified and quantified in the preceding sections could affect the operation of the electric power system. The contribution of these causes to the unavailability of power for each of the system failure states depends on the nature of the specific hardware failures required to achieve the loss of power and the anticipated impact these unidentified causes have on these components.

It is important to emphasize that these causes are unidentified. They have not been observed during the operational history of Indian Point Unit 2 and are difficult to conceptualize through any specific failure scenario. Furthermore, because many unobserved causes have been specifically identified and quantified in the preceding sections, it is expected that the failure contribution from these other causes will be significantly lower than any of those presented thus far in the analysis.

The quantification of this contribution, although subjective in nature, is possible through a conservative assessment of the analysis developed in the preceding sections of this study. There is high confidence that the total contribution to each system failure state from these

unidentified causes is much less than that presented by the least contributing identified cause. However, for conservatism, the 95th percentile of the "other causes" distribution is set equal to the mean of this smallest identified contributor. (This process essentially assigns a 95% confidence to the ability to identify the significant contributors to failure for any possible failure state.) The precise contribution from these causes is highly uncertain. Therefore, a range of three orders of magnitude is assigned between the 5th and 95th percentiles of the assumed lognormal distribution. The resulting distribution for the contribution of these other causes thus depends on the magnitude of the smallest identifed cause for each electric power system failure state and is characterized by the following parameters:

95th percentile = mean value of smallest identified cause distribution

5th percentile = (95th percentile) x 10^{-3}

It is believed that this distribution provides a very conservative upper bound estimate of the impact of these other causes. The contribution of this cause category to each of the electric power system failure states is shown in the summary tables discussed in Section 1.5.2.2.1.4.7.

1.5.2.2.1.4.7 System Failure State Summaries. Tables 1.5.2.2.1-12A and 1.5.2.2.1-12B summarize the contributions to each of the Indian Point Unit 2 electric power system failure states from each of the cause categories discussed in the preceding sections of this study. The hardware, testing error, maintenance and fuel supply failure contributors are developed in Section 1.5.2.2.1.4.5 and are shown in Tables 1.5.2.2.1-10A through 1.5.2.2.1-100 and 1.5.2.2.1-11A through 1.5.2.2.1-110. The human error contributors have been calculated by multiplying the diesel generator unavailability distributions resulting from these causes (presented in Section 1.5.2.2.1.4.6) by the corresponding conditional power failure distributions for the various states of diesel generator inoperability shown in Tables 1.5.2.2.1-10A through 1.5.2.2.1-100 and 1.5.2.2.1-11A through 1.5.2.2.1-110. The quantification of the unidentified "other causes" contributor is discussed in detail in Section 1.5.2.2.1.4.6.4.

Although each of these contributing causes has been developed separately in this analysis, they are not independent and, therefore, cannot simply be summed to produce the total unavailability of power for each system failure state. Examples illustrating the dependencies between causes are that fuel supply failure can lead to loss of power only if no other diesel generator failures occur; hardware failures can occur only if the affected components are not tagged out of service for maintenance. It is conservatively assumed that the unidentified "other causes" of system failure can occur independently of any of the identified causes. The

following variables are used to define each of the given cause categories:

Q_H = unavailability due to hardware failures

Q_M = unavailability due to components out of service for maintenance

Q_T = unavailabiltity due to human error following testing

Q_{FS} = unavailability due to fuel supply failures

Q_{HE} = unavailability due to human errors during maintenance

Q_O = unavailability due to other (unidentified) causes

The distributions for these failure contributors are combined to produce the total unavailability distribution for each electric power system failure state through the following expression, which specifically identifies the significant dependencies among the various cause categories:

$$Q_{Total} = Q_H \times [(1 - Q_M)(1 - Q_T)(1 - Q_{HE})(1 - Q_{FS})] + Q_M \times (1 - Q_T)$$
$$+ Q_{FS} \times [(1 - Q_H)(1 - Q_M)(1 - Q_T)(1 - Q_{HE})] + Q_T \times (1 - Q_M)$$
$$+ Q_{HE} \times [(1 - Q_M)(1 - Q_T)] + Q_O$$

The "total" columns in Tables 1.5.2.2.1-12A and 1.5.2.2.1-12B characterize the distributions for the unavailability of power in each of the system failure states obtained from the combined contributions of all possible causes, including the dependencies among these cause categories.

Each of the failure state distributions presented in Tables 1.5.2.2.1-12A and 1.5.2.2.1-12B has been developed by considering all possible contributors to failure without regard to the impact these contributors have on other system failure states. Therefore, these distributions are the quantification of the nonmutually exclusive unavailabilities discussed in Section 1.5.2.2.1.3.2. To apply the electric power system analysis to the quantification of the event trees, each of the electric power failure states must be mutually exclusive (e.g., the "Failure of Power at Buses 2A and 5A" must represent the system state of no power at bus 2A, no power at bus 5A, <u>and</u> power <u>is</u> available at buses 3A and 6A).

The discussion in Section 1.5.2.2.1.3.2 provides the basis for determining the required mutually exclusive failure state unavailability distributions from the results summarized in Tables 1.5.2.2.1-12A and 1.5.2.2.1-12B. For each of the desired mutually exclusive failure states, a logic expression which accounts for the relative contributions from each of the nonmutually exclusive states can be constructed (refer to the determination of the shaded area of the Venn diagram in

Section 1.5.2.2.1.3.2). The mutually exclusive failure distribution for the failure of power at only bus 2A is determined from the following combination of nonmutually exclusive failure distributions (the circled numbers correspond to the identification numbers of the failure states presented in Tables 1.5.2.2.1-12A and 1.5.2.2.1-12B).

Unavailability of power at only bus 2A is

$$(2) - ((6) + (7) + (8)) + ((12) + (13) + (14)) - (16)$$

Similarly,

Unavailability of power at only bus 3A is

$$(3) - ((6) + (9) + (10)) + ((12) + (13) + (15)) - (16)$$

The quantification of the other two mutually exclusive single bus failure states follows the same logic. The expression for the mutually exclusive failure of power at only buses 2A and 3A is given by

Unavailability of power at only buses 2A and 3A is

$$(6) - ((12) + (13)) + (16)$$

and

Unavailability of power at only buses 2A and 5A is

$$(7) - ((12) + (14)) + (16)$$

The remaining mutually exclusive two-bus failure states are obtained in the same manner. Extending this logic to the mutually exclusive state of failure of power at buses 2A, 3A and 5A results in

Unavailability of power at only buses 2A, 3A and 5A is

$$(12) - (16)$$

The expressions for the other three-bus states are similar. Because the failure of power at all four buses is a unique event for this system, the mutually exclusive distribution for this failure state is identical to the nonmutually exclusive distribution.

Once the 15 mutually exclusive failure states have been determined, the remaining possible state of the electric power system (i.e., the state in which power is available at all four buses) is defined by the following expression:

Probability that power is available at all four buses
$= 1.0 - \Sigma$ (15 mutually exclusive failure states).

Tables 1.5.2.2.1-2A and 1.5.2.2.1-2B present the results of this process and are the logically complete, mutually exclusive electric power system failure state distributions for each of the specified system analysis boundary conditions.

1.5.2.2.1.4.8 Interface with Event Tree Quantification. The Indian Point Unit 2 electric power system is analyzed for the unavailability of power for each of 16 possible system operability states under two different boundary conditions. To interface directly with the quantification of the event trees developed for this study, these electric power system failure states must be carefully examined and combined to satisfy the appropriate initiating event analysis boundary conditions.

The loss of offsite power initiating event requires failure of at least the 345 kV and 138 kV offsite power supplies to Unit 2. (These are the minimum failures required to cause a unit trip and failure of all offsite power, if no operator actions are considered.) The electric power system failure state quantifications directly applicable to this initiating event are summarized in Table 1.5.2.2.1-2A. For completeness, these results are repeated in Table 1.5.2.2.1-2C for the "Loss of Offsite Power" initiating event.

It is assumed in this study that all initiating events ultimately result in a trip of the main generator. Because Indian Point Unit 2 is rated at 873 MW(e), the instantaneous loss of this input could have a significant effect upon the stability of the offsite power supply network due to reduced transmission voltages, frequency fluctuations, or power flow imbalances as the grid recovers from the transient. The Consolidated Edison transmission network has been designed to provide a stable power supply grid under conditions of multiple large generating unit and major transmission line outages. Detailed guidelines have been established for the entire Consolidated Edison power supply network which define the basis for system operation under a wide variety of steady state and transient conditions. A prime consideration in the establishment of these guidelines is the requirement that no single loss of a generating unit or transmission facility should result in an unacceptable condition of degraded system operation. System operating contingencies are defined by these guidelines and specify the need to provide additional generating capacity from Consolidated Edison's own facilities or to provide power from network interties long before critical operating stability limits are approached. A detailed voltage reduction and selective load shedding program is also specified to maintain grid stability with adequate margins under the most severe conditions. Detailed system stability studies have been performed to verify the efficacy of these operating guidelines under a wide range of scenarios.

The assignment of a distribution for the probability of losing offsite power to Indian Point Unit 2 as a result of a trip of that unit is extremely difficult. Factors affecting this condition are total system load, available spinning reserve capacity, the fraction of the load being supplied from the Indian Point units, the status of neighboring utilities' networks, scheduled and unscheduled outages of specific generating units and transmission lines, etc. The analysis of this problem presented in the RSS applies a median value of 10^{-3} for the conditional loss of offsite power as a result of a unit trip.*

*Reactor Safety Study, Appendix II, page 34

Several factors limit the applicability of this value for use in this study. The RSS distribution was developed from a review of Federal Power Commission studies of power supply networks in a wide variety of locations east of the Rocky Mountains. While it may be applicable to the composite site studied in the RSS, it is not directly applicable to the Indian Point site. Additionally, the reference study is now several years old and significant advances in the design, operation, and overall stability of most transmission networks in the United States have been made during the intervening years.

A detailed study of the availability of offsite power to the Indian Point site was undertaken by the Consolidated Edison Electrical Planning Department in support of this project. This study provided a macroscopic analysis of the independent hardware failure contributors to the unavailability of offsite power at the Buchanan substation. Local grid failures and Consolidated Edison interconnected system failures were investigated. The analysis used Consolidated Edison historical component failure data, when available, and generic industry data when no specific failure data were found. The assumptions and boundary conditions applied to the analysis provided a pessimistic assessment of system-wide and localized grid stability within the established system operating and design criteria. The study results conclude that the unavailability of offsite power at the Buchanan substation due to independent hardware failures is approximately 3.88×10^{-8}, without regard to the status of either of the Indian Point units. The stated uncertainty in these results is one to two orders of magnitude, primarily due to uncertainties in the component failure data bases applied.

The Consolidated Edison study provides a firm basis for a lower limit estimation of the probability of failure of offsite power due to a trip of one of the Indian Point units. Power availability at the Buchanan substation should be no better than that evaluated through the analysis of these independent failures. However, the study does not consider the effects of common cause hardware failures or the effects of multiple component unavailabilities due to causes such as nonroutine maintenance, construction, system contingencies, etc. Furthermore, the analysis has not evaluated the contributions to power failure from local or system-wide transient instabilities which could be initiated or aggravated by the trip of a large generating unit under rare severe operating contingency conditions.

For these reasons, the conditional power unavailability at Buchanan substation, given a trip of either Indian Point unit, could be higher than that evaluated in the Consolidated Edison study. To quantify the impact of this conditional power failure state on risk, the following approach was adopted for this study. An uncertainty of one order of magnitude was applied to the Consolidated Edison analysis results. The value of 3.88×10^{-7} was then assigned as the 5th percentile of an assumed lognormal distribution for this conditional loss of power.

Because very little evidence is available for the quantification of the upper limits of this distribution, the value of 1.0×10^{-3} from the RSS study was conservatively assigned as the 95th percentile. Therefore, the following parameters are used in this study to characterize the distribution to be applied for the probability of losing offsite power to Indian Point Unit 2 as a result of any trip of that unit:

5th Percentile:	3.88×10^{-7} failure/unit trip
95th Percentile:	1.00×10^{-3} failure/unit trip
Median:	1.97×10^{-5} failure/unit trip
Mean:	3.41×10^{-4} failure/unit trip
Variance:	3.45×10^{-5}

A few observations will place this distribution in proper perspective. It is a subjective best estimate of a conservative distribution and can be applied to this analysis only. Although it is broadly based on the results of the Consolidated Edison power unavailability study performed for the Indian Point site, that study provided substantial information for the estimation of the lower bound only. However, the Consolidated Edison analysis demonstrates the extreme stability of the power supply grid at Buchanan under severe operating conditions and reinforces the belief that the conditional power failure distribution for Indian Point lies below that applied in the RSS.

The median value of the distribution is believed to be a very conservative estimate for the frequency of this event. However, it is also believed that the assigned broad distribution adequately accounts for the uncertainty in this value. Thus, the given distribution is considered to represent a conservatively bounding estimate for the conditional failure of offsite power, which is specialized to the Indian Point site as much as is possible with the existing information base.

For all initiating events other than the loss of offsite power initiator, offsite power is considered to be available immediately before event initiation. Because each event results in the loss of the main generator, the electric power unavailability for each of the system operability states must be evaluated in light of the probability that offsite power could be lost as a result of the unit trip. The distributions presented in Tables 1.5.2.2.1-2A and 1.5.2.2.1-2B are based on the existence of clearly defined boundary conditions. The following general quantities are also defined:

$Q(X, O)$ = unavailability of power in state X, given offsite power available

$Q(X, \overline{O})$ = unavailability of power in state X, given offsite power not available

$P(\overline{O}, T)$ = probability of losing offsite power due to a unit trip

$Q(X, T)$ = unavailability of power in state X, given that a unit trip has occurred

For any initiator other than the loss of offsite power,

$$Q(X, T) = Q(X, \overline{O}) \times P(\overline{O}, T) + Q(X, O) \times [1 - P(\overline{O}, T)]$$

Table 1.5.2.2.1-2D presents the mutually exclusive electric power system operability state distributions which are applicable to initiating events other than the loss of offsite power. They have been computed by combining the distributions from Tables 1.5.2.2.1-2A and 1.5.2.2.1-2B with the distribution for the conditional loss of offsite power discussed previously.

1.5.2.2.1.4.9 Recoverability Factors. To develop consistent failure probabilities to be applied to all the event sequences analyzed in this study, the electric power system failure states have been quantified under the limiting condition of an operator recovery failure rate of unity applicable to those situations in which power is lost due to equipment inoperability or failure. This is a very pessimistic assessment of human response, but it is not meant to be applied as a model of real behavior. Rather, it represents a convenient method for temporarily removing a very complex and subjective influence from the treatment of a detailed system analysis which must be consistently applied to a wide variety of event scenarios. Human response to system failures cannot be neglected. However, the quantitative treatment of that response is made manageable by addressing the issue in detail only in those specific instances in which the lack of response is critical to overall plant recovery success or failure.

The actions that the plant operators must take for recovery of any portion of the electric power system vary from simple manual operations of circuit breaker controls at the main control room panels to rather complex local manual switching, starting, and control of the emergency diesel generators and provision of emergency power supplies from onsite and nearsite sources. The nature of the required actions depends on the observed system failures. The required response time is determined by the magnitude of the failure and its effects on the operation of those safeguards systems necessary to maintain the plant in a stable condition under the imposed initiating event scenario. The operator's failure rate in response to the emergency is influenced by its actual magnitude, the perceived urgency, the presence of conflicting or confusing indications, his training and written procedural guidance, and additional technical, physical, and psychological factors too numerous to consider explicitly in this study. The task of assigning a measure of confidence in the operator's performance under these conditions is not as difficult as it might seem at first glance. However, to provide a meaningful assessment of his likely behavior, a precise description of

the situation with which he is faced must be provided. "Best estimate" quantifications of human performance under the worst case conditions applied to a broad range of scenarios are no more accurate than are very optimistic assessments of simple actions that are applied to complex and confusing situations requiring rapid and correct assessment and response.

A summary of the available operator actions and the applicable times for successful performance of these actions to mitigate a wide variety of the failures quantified in Section 1.5.2.2.1.4.5 is provided in this section. The general methodology for the assignment of human error rates under time dependent situations of varying stress levels and with varying degrees of operator assistance is described in a separate section of this study. The detailed application of this methodology is deferred until the scenarios in which it must be applied are completely defined (i.e., until the precise event sequences in which these actions are required have been identified).

Tables 1.5.2.2.1-13A and 1.5.2.2.1-13B summarize the recovery actions which are most likely to reduce the consequences of or completely mitigate each of the electric power system failure states presented in Section 1.5.2.2.1.4.5. Also included are estimates of the time required for the performance of each of these actions. This summary is not an exhaustive documentation of all possible recovery actions; it is simply an assessment of the most direct methods available for coping with each of the analyzed failure states based on information such as automatic system response and dominant contributors to failure. Because the loss of offsite power and its effects on the availability of the electric power system are of particular significance, several recovery actions available for the restoration of this vital source of power are summarized in Table 1.5.2.2.1-14.

1.5.2.2.1.5 Conclusions. The Indian Point Unit 2 electric power system has been analyzed for the failure of power at the 480V essential switchgear buses during the 6-hour period immediately following an initiating event. This analysis provides a very conservative upper bound for the unavailability of power in each of the system failure states examined. Operator actions for the recovery of failed components have not been included because the analysis has been developed for a broad range of initiating event scenarios. It is unrealistically pessimistic to assume that nothing can be done to restore power during a period as long as 6 hours. However, the impact of that power recovery and the probability of successful operator response are highly dependent on the precise event scenario during which the failures occur. The bounding analysis presented in this study will be used in the identification of those event sequences in which electric power failure has a significant impact on risk. Once these dominant sequences have been identified, the boundary conditions will be established for the inclusion and quantification of specific power recovery actions.

Sixteen electric power system operability states have been quantified for each of two analysis boundary conditions. The more restrictive of these boundary conditions is that in which all offsite power remains unavailable for the entire 6-hour study period. "Offsite power" is defined in this analysis as including, at a minimum, the 345 kV and 138 kV offsite power supplies to Unit 2. Because manual operator recovery actions are excluded from this analysis, the unavailability of offsite power does not define the status of the 13.8 kV offsite supply from the Buchanan substation or the status of any of the gas turbines available to the site. The availability of these reserve offsite supplies will significantly affect the time required to recover a source of power from other than the diesel generators, but it has had no impact on this conservatively bounding failure analysis. The quantification of offsite power recovery, including the effects of the gas turbine units, will be included in the overall plant recoverability analysis for those event sequences in which offsite power failure proves to be a dominant contributor to risk.

If the diesel generators provide the only possible source of power to the 480V essential buses, the dominant failure cause contributors are diesel generator failures and diesel generator unavailability due to maintenance. Diesel fuel oil transfer system failures contribute significantly to failure states involving three or more buses. However, this specific failure cause must be placed in a proper perspective. Because the analysis is extended for a period of 6 hours following event initiation, the fuel oil transfer system is required to maintain all three of the diesel generators operating. Analysis periods of less than 1 hour would not require transfer system operation, because of the normal fuel reserve in each diesel generator's day tank. The most important contributor to failure of the fuel oil transfer system is the failure of plant personnel to restore power to the transfer pump motor control centers after their supply breakers are tripped by the power blackout signal.

With offsite power available, a significant contributing cause to each of the failure states is that the normal power supply to each of the

essential buses is automatically tripped when an undervoltage condition is detected at either bus 5A or bus 6A. This loss of normal power, combined with the subsequent failures and maintenance unavailability of the diesel generators, is the most significant contributor to each power failure state. It must again be emphasized that these contributions represent extremely conservative upper bounds, since no credit is taken for operator actions to recover power to any of the buses over a period of 6 hours.

Following any transient other than the loss of offsite power initiating event, the probability of losing the offsite power supply as a result of the unit trip is extremely low. Even though this analysis is conservatively bounding and includes no power recovery considerations, the availability of the Indian Point Unit 2 electric power system is extremely high under these conditions.

The loss of offsite power transient has the most severe impact on the electric power system. The results reported in this analysis do not take credit for any operator actions to recover either onsite components or offsite power at any time during the 6-hour period following event initiation. Absolutely no consideration has been given in this bounding analysis to the operation or availability of the gas turbines at the Indian Point site or Buchanan substation. Even under extremely severe conditions affecting the offsite power supply grid, these units should provide a reserve source of power available to station personnel well within the 6-hour period covered by this analysis. Therefore, it is believed that the inclusion of recovery actions will significantly improve the availabilty of power in all of these electric power operability states. However, the quantification of these effects is deferred to the detailed evaluation of specific event sequences in which electric power failure contributes significantly to risk. The timeframes available for plant recovery and the response characteristics of plant operating personnel are defined through these specific event sequences. This information provides a necessary input to the final quantification of not only electric power recovery actions, but also to the specific efforts made to minimize the consequences of the given event scenario.

The intricacies and operational complexities of the Indian Point Unit 2 electric power system have necessitated the bounding analysis approach adopted in this study. The results presented in this section do not provide the full quantification of the contribution to risk from electric power failures. The conservative boundary conditions and restrictive guidelines imposed on this analysis ensure that the results provide bounding values for any of the event sequences studied. However, vital interactions between the operators and the electric power system have been omitted from this analysis and cannot be effectively evaluated until specific event sequences are clearly defined. Therefore, it is extremely restrictive and improper to remove this system analysis from the context of the main study. The full effects of electric power system failures are important only as they affect risk. Therefore, these effects, including operator recovery actions, are quantified in detail only at the specific event sequence level.

TABLE 1.5.2.2.1-1

INDIAN POINT UNIT 2 ELECTRIC POWER SYSTEM OPERABILITY STATES

State	No Power at Bus(es)	Power Available at Bus(es)
1	-	All buses
2	2A	3A, 5A, 6A
3	3A	2A, 5A, 6A
4	5A	2A, 3A, 6A
5	6A	2A, 3A, 5A
6	2A, 3A	5A, 6A
7	2A, 5A	3A, 6A
8	2A, 6A	3A, 5A
9	3A, 5A	2A, 6A
10	3A, 6A	2A, 5A
11	5A, 6A	2A, 3A
12	2A, 3A, 5A	6A
13	2A, 3A, 6A	5A
14	2A, 5A, 6A	3A
15	3A, 5A, 6A	2A
16	All buses	-

TABLE 1.5.2.2.1-2A

INDIAN POINT 2 ELECTRIC POWER SYSTEM MUTUALLY EXCLUSIVE FAILURE STATES - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

State	Failure of Power at Bus(es)	Frequency of Given Electric Power State				
		Mean	Median	Variance	5th Percentile	95th Percentile
1	-	8.59×10^{-1}	8.58×10^{-1}	2.50×10^{-4}	8.28×10^{-1}	8.81×10^{-1}
2	2A	$< 5 \times 10^{-5}$*				
3	3A	$< 5 \times 10^{-5}$*				
4	5A	4.54×10^{-2}	4.38×10^{-2}	8.55×10^{-5}	3.09×10^{-2}	5.92×10^{-2}
5	6A	4.54×10^{-2}	4.38×10^{-2}	8.55×10^{-5}	3.09×10^{-2}	5.92×10^{-2}
6	2A, 3A	4.54×10^{-2}	4.38×10^{-2}	8.55×10^{-5}	3.09×10^{-2}	5.92×10^{-2}
7	2A, 5A	$< 5 \times 10^{-6}$*				
8	2A, 6A	$< 5 \times 10^{-6}$*				
9	3A, 5A	$< 5 \times 10^{-6}$*				
10	3A, 6A	$< 5 \times 10^{-6}$*				
11	5A, 6A	1.53×10^{-3}	1.42×10^{-3}	2.12×10^{-7}	8.03×10^{-4}	2.24×10^{-3}
12	2A, 3A, 5A	1.53×10^{-3}	1.42×10^{-3}	2.12×10^{-7}	8.03×10^{-4}	2.24×10^{-3}
13	2A, 3A, 6A	1.53×10^{-3}	1.42×10^{-3}	2.12×10^{-7}	8.03×10^{-4}	2.24×10^{-3}
14	2A, 5A, 6A	$< 5 \times 10^{-8}$*				
15	3A, 5A, 6A	$< 5 \times 10^{-8}$*				
16	All buses	8.82×10^{-5}	8.31×10^{-5}	8.56×10^{-10}	4.59×10^{-5}	1.36×10^{-4}

*Bounded by a more limiting failure state.

TABLE 1.5.2.2.1-2B

INDIAN POINT 2 ELECTRIC POWER SYSTEM MUTUALLY EXCLUSIVE FAILURE STATES - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

State	Failure of Power at Bus(es)	Frequency of Given Electric Power State				
		Mean	Median	Variance	5th Percentile	95th Percentile
1	-	1.00	1.00	1.33×10^{-9}	1.00	1.00
2	2A	3.93×10^{-5}	3.05×10^{-5}	6.86×10^{-10}	8.73×10^{-6}	7.93×10^{-5}
3	3A	3.93×10^{-5}	3.05×10^{-5}	6.86×10^{-10}	8.73×10^{-6}	7.93×10^{-5}
4	5A	1.60×10^{-6}	1.41×10^{-6}	4.85×10^{-13}	6.65×10^{-7}	2.66×10^{-6}
5	6A	1.60×10^{-6}	1.41×10^{-6}	4.85×10^{-13}	6.65×10^{-7}	2.66×10^{-6}
6	2A, 3A	1.44×10^{-6}	1.27×10^{-6}	4.39×10^{-13}	5.72×10^{-7}	2.45×10^{-6}
7	2A, 5A	$< 2 \times 10^{-10}$*				
8	2A, 6A	$< 2 \times 10^{-10}$*				
9	3A, 5A	$< 2 \times 10^{-10}$*				
10	3A, 6A	$< 2 \times 10^{-10}$*				
11	5A, 6A	6.40×10^{-8}	5.70×10^{-8}	6.43×10^{-16}	2.68×10^{-8}	1.03×10^{-7}
12	2A, 3A, 5A	5.59×10^{-8}	4.95×10^{-8}	5.39×10^{-16}	2.24×10^{-8}	9.18×10^{-8}
13	2A, 3A, 6A	5.59×10^{-8}	4.95×10^{-8}	5.39×10^{-16}	2.24×10^{-8}	9.18×10^{-8}
14	2A, 5A, 6A	$< 5 \times 10^{-12}$*				
15	3A, 5A, 6A	$< 5 \times 10^{-12}$*				
16	All buses	3.32×10^{-9}	3.15×10^{-9}	1.59×10^{-18}	1.56×10^{-9}	5.39×10^{-9}

*Bounded by a more limiting failure state.

TABLE 1.5.2.2.1-2C

INDIAN POINT 2 ELECTRIC POWER SYSTEM MUTUALLY EXCLUSIVE FAILURE STATES - LOSS OF OFFSITE POWER INITIATING EVENT

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

State	Failure of Power at Bus(es)	Frequency of Given Electric Power State				
		Mean	Median	Variance	5th Percentile	95th Percentile
1	-	8.59×10^{-1}	8.58×10^{-1}	2.50×10^{-4}	8.28×10^{-1}	8.81×10^{-1}
2	2A	$< 5 \times 10^{-5}$*				
3	3A	$< 5 \times 10^{-5}$*				
4	5A	4.54×10^{-2}	4.38×10^{-2}	8.55×10^{-5}	3.09×10^{-2}	5.92×10^{-2}
5	6A	4.54×10^{-2}	4.38×10^{-2}	8.55×10^{-5}	3.09×10^{-2}	5.92×10^{-2}
6	2A, 3A	4.54×10^{-2}	4.38×10^{-2}	8.55×10^{-5}	3.09×10^{-2}	5.92×10^{-2}
7	2A, 5A	$< 5 \times 10^{-6}$*				
8	2A, 6A	$< 5 \times 10^{-6}$*				
9	3A, 5A	$< 5 \times 10^{-6}$*				
10	3A, 6A	$< 5 \times 10^{-6}$*				
11	5A, 6A	1.53×10^{-3}	1.42×10^{-3}	2.12×10^{-7}	8.03×10^{-4}	2.24×10^{-3}
12	2A, 3A, 5A	1.53×10^{-3}	1.42×10^{-3}	2.12×10^{-7}	8.03×10^{-4}	2.24×10^{-3}
13	2A, 3A, 6A	1.53×10^{-3}	1.42×10^{-3}	2.12×10^{-7}	8.03×10^{-4}	2.24×10^{-3}
14	2A, 5A, 6A	$< 5 \times 10^{-8}$*				
15	3A, 5A, 6A	$< 5 \times 10^{-8}$*				
16	All buses	8.82×10^{-5}	8.31×10^{-5}	8.56×10^{-10}	4.59×10^{-5}	1.36×10^{-4}

*Bounded by a more limiting failure state.

TABLE 1.5.2.2.1-2D

INDIAN POINT 2 ELECTRIC POWER SYSTEM MUTUALLY EXCLUSIVE FAILURE STATES - INITIATING EVENTS OTHER THAN LOSS OF OFFSITE POWER

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

State	Failure of Power at Bus(es)	Frequency of Given Electric Power State				
		Mean	Median	Variance	5th Percentile	95th Percentile
1	-	1.00	1.00	8.26×10^{-7}	1.00	1.00
2	2A	3.93×10^{-5}	3.08×10^{-5}	6.03×10^{-10}	1.07×10^{-5}	7.73×10^{-5}
3	3A	3.93×10^{-5}	3.08×10^{-5}	6.03×10^{-10}	1.07×10^{-5}	7.73×10^{-5}
4	5A	1.71×10^{-5}	4.62×10^{-6}	2.34×10^{-9}	1.01×10^{-6}	2.84×10^{-5}
5	6A	1.71×10^{-5}	4.62×10^{-6}	2.34×10^{-9}	1.01×10^{-6}	2.84×10^{-5}
6	2A, 3A	1.69×10^{-5}	4.46×10^{-6}	2.34×10^{-9}	9.00×10^{-7}	2.82×10^{-5}
7	2A, 5A	$< 2 \times 10^{-9}$*				
8	2A, 6A	$< 2 \times 10^{-9}$*				
9	3A, 5A	$< 2 \times 10^{-9}$*				
10	3A, 6A	$< 2 \times 10^{-9}$*				
11	5A, 6A	5.86×10^{-7}	1.64×10^{-7}	2.64×10^{-12}	3.96×10^{-8}	1.39×10^{-6}
12	2A, 3A, 5A	5.78×10^{-7}	1.55×10^{-7}	2.64×10^{-12}	3.59×10^{-8}	1.38×10^{-6}
13	2A, 3A, 6A	5.78×10^{-7}	1.55×10^{-7}	2.64×10^{-12}	3.59×10^{-8}	1.38×10^{-6}
14	2A, 5A, 6A	$< 3 \times 10^{-11}$*				
15	3A, 5A, 6A	$< 3 \times 10^{-11}$*				
16	All buses	3.34×10^{-8}	8.61×10^{-9}	8.88×10^{-15}	2.22×10^{-9}	6.53×10^{-8}

*Bounded by a more limiting failure state.

TABLE 1.5.2.2.1-3

INDIAN POINT 2 480V ESSENTIAL BUS LOADING

Bus	Load
Bus 2A	Pressurizer Heaters Backup Group 22 Component Cooling Pump 22 Service Water Pump 22 (redundant supply from bus 3A) Service Water Pump 25 (redundant supply from bus 3A) Safety Injection Pump 22 (redundant supply from bus 3A) Fan Cooler Unit 23 De-Icing Pump 21 Rod Power Supply M-G Set 21 MCC 21 MCC 23 MCC 24 MCC 210 Lighting Transformer 21 (normal supply)
Bus 3A	Pressurizer Heaters Backup Group 21 Component Cooling Pump 23 Service Water Pump 22 (redundant supply from bus 2A) Service Water Pump 25 (redundant supply from bus 2A) Safety Injection Pump 22 (redundant supply from bus 2A) Residual Heat Removal Pump 21 Auxiliary Feedwater Pump 21 Fan Cooler Unit 24 Charging Pump 22 De-Icing Pump 22 MCC 22 MCC 25 Lighting Transformer 22
Bus 5A	Pressurizer Heaters Backup Group 23 Safety Injection Pump 21 Containment Spray Pump 21 Recirculation Pump 21 Component Cooling Pump 21 Service Water Pump 21 Service Water Pump 24 Fan Cooler Unit 21 Fan Cooler Unit 22 Charging Pump 21 Service Air Compressor MCC 26A MCC 28 MCC 29 Lighting Transformer 23

TABLE 1.5.2.2.1-3 (continued)

INDIAN POINT 2 480V BUS LOADING

Bus	Load
Bus 6A	Pressurizer Heaters Control Group Safety Injection Pump 23 Containment Spray Pump 22 Recirculation Pump 22 Residual Heat Removal Pump 22 Service Water Pump 23 Service Water Pump 26 Auxiliary Feedwater Pump 23 Fan Cooler Unit 25 Charging Pump 23 Rod Power Supply M-G Set 22 Main Turbine Auxiliary Lube Oil Pump MCC 26B MCC 27 MCC 211 Lighting Transformer 21 (emergency supply)

TABLE 1.5.2.2.1-4

INDIAN POINT 2 DIESEL GENERATOR
AUXILIARIES POWER SUPPLIES

Diesel Generator 21	
Crankcase Exhauster	
(normal supply)	MCC 26A
(reserve supply)	MCC 26B
Starting Air Compressor	MCC 27
Fuel Oil Transfer Pump 21	MCC 29
Diesel Generator Control Power	
(normal supply)	DC Power Panel 21
(reserve supply)	DC Power Panel 23
Output Breaker Control Power	
(normal supply)	DC Power Panel 21
(reserve supply)	DC Power Panel 23
Diesel Generator 22	
Crankcase Exhauster	
(normal supply)	MCC 26B
(reserve supply)	MCC 26A
Starting Air Compressor	MCC 29
Fuel Oil Transfer Pump 22	MCC 24
Diesel Generator Control Power	
(normal supply)	DC Power Panel 22
(reserve supply)	DC Power Panel 23
Bus 2A Output Breaker Control Power	
(normal supply)	DC Power Panel 22
(reserve supply)	DC Power Panel 24
Bus 3A Output Breaker Control Power	
(normal supply)	DC Power Panel 21
(reserve supply)	DC Power Panel 23
Diesel Generator 23	
Crankcase Exhauster	
(only supply)	MCC 26B
Starting Air Compressor	MCC 27
Fuel Oil Transfer Pump 23	MCC 27
Diesel Generator Control Power	
(normal supply)	DC Power Panel 22
(reserve supply)	DC Power Panel 24
Output Breaker Control Power	
(normal supply)	DC Power Panel 22
(reserve supply)	DC Power Panel 24

TABLE 1.5.2.2.1-5

INDIAN POINT 2 DIESEL GENERATOR - FUEL OIL TRANSFER PUMP STARTING LOGIC

Low Level in Fuel Oil Day Tank for Diesel Generator	Primary Fuel Oil Transfer Pump (starts first)	Backup Fuel Oil Transfer Pump (starts if primary pump fails)
21	21	23
22	22	21
23	23	22

TABLE 1.5.2.2.1-6

INDIAN POINT 2 MAJOR DC POWER SYSTEM LOADS

Power Panel 21	Main Turbine Emergency Oil Pump Instrument Bus 21 Static Inverter 6.9 kV Buses 1, 2, and 5 Control Power 480V Buses 3A and 5A Control Power (normal supply) Train A Reactor Trip Breakers Control Power Control Rod Position Indication Inverter Conventional Plant Emergency Lighting Control Room Emergency Lighting Diesel Generator Building Emergency Lighting Distribution Panel 21 Distribution Panel 21A
Distribution Panel 21	Safety Injection System Valves Control Power Diesel Generator 21 Control Power (normal supply) Main Steam Dump Control Main Generator Trip Relays Main Turbine Trip Relays Station Auxiliary Transformer Trip Relays Safeguards Actuation Train A Relays Reactor Coolant System Overpressurization Protection Train A
Distribution Panel 21A	Reactor Protection Train A Relays Miscellaneous Plant Fire Protection System Controls
Power Panel 22	Main Feedwater Pumps Emergency Oil Pump Air Side Seal Oil Backup Pump Instrument Bus 22 Static Inverter 6.9 kV Buses 3, 4, and 6 Control Power 480V Buses 2A and 6A Control Power (normal supply) Train B Reactor Trip Breakers Control Power Nuclear Plant Emergency Lighting Distribution Panel 22 Distribution Panel 22A
Distribution Panel 22	Safety Injection System Valves Control Power Diesel Generators 22 and 23 Control Power (normal supply) Main Generator Backup Trip Relays Main Turbine Backup Trip Relays Station Auxiliary Transformer Backup Trip Relays Safeguards Actuation Train B Relays Reactor Protection Train B Relays

TABLE 1.5.2.2.1-6 (continued)

INDIAN POINT 2 MAJOR DC POWER SYSTEM LOADS

Distribution Panel 22A	Reactor Coolant System Overpressurization Protection Train B Reactor Analog Protection Inverter
Power Panel 23	Instrument Bus 23 Static Inverter 480V Buses 3A and 5A Control Power (reserve supply) Diesel Generators 21 and 22 Control Power (reserve supply)
Power Panel 24	Instrument Bus 24 Static Inverter 480V Buses 2A and 6A Control Power (reserve supply) Diesel Generator 23 Control Power (reserve supply)

TABLE 1.5.2.2.1-7

INDIAN POINT 2 118 VAC INSTRUMENT BUS POWER SUPPLIES

Instrument Bus	Static Inverter	DC Power Panel (normal supply)	AC Power Supply (reserve supply)
21	21	21	MCC 26A*
22	22	22	MCC 24*
23	23	23	120 VAC Lighting Bus 22**
24	24	24	MCC 26B*

*Through 480/120V stepdown and constant voltage solatron transformers.

**Through constant voltage solatron transformer (normal power supply to 120 VAC lighting bus 22 is from bus 3A through 480/120V lighting transformer 22).

TABLE 1.5.2.2.1-8

INDIAN POINT 2 ELECTRIC POWER FAILURE INITIATING EVENTS

System Failure	Initiating Event Category
Loss of Offsite Power Supply from Station Auxiliarly Transformer	Loss of Offsite Power
Loss of Power to Any 6.9 kV Bus	Loss of Primary Flow
Loss of Power at DC Power Panel 21 or 22	Reactor Trip
Loss of Power to Any Two Instrument Power Buses	Reactor Trip or Safety Injection (depends upon which buses are deenergized)

TABLE 1.5.2.2.1-9

INDIAN POINT 2 ELECTRIC POWER FAULT TREE BASIC EVENT DESCRIPTION, COMPONENT FAILURE MODE CODING, AND FAILURE RATES

Component	Failure Mode	Coding	Failure Rate(1)	Reference(2)
6.9 kV Bus 2	Open Circuit	JBS6922K	2.80×10^{-8}	37
6.9 kV Bus 3	Open Circuit	JBS6923K	2.80×10^{-8}	37
6.9 kV Bus 5	Open Circuit	JBS6925K	2.80×10^{-8}	37
6.9 kV Bus 6	Open Circuit	JBS6926K	2.80×10^{-8}	37
480V Bus 2A	Open Circuit	JBS-22AK	2.80×10^{-8}	37
480V Bus 3A	Open Circuit	JBS-23AK	2.80×10^{-8}	37
480V Bus 5A	Open Circuit	JBS-25AK	2.80×10^{-8}	37
480V Bus 6A	Open Circuit	JBS-26AK	2.80×10^{-8}	37
DC Power Panel 21	Open Circuit	4BS-221K	2.80×10^{-8}	37
DC Power Panel 22	Open Circuit	4BS-222K	2.80×10^{-8}	37
DC Power Panel 23	Open Circuit	4BS-223K	2.80×10^{-8}	37
DC Power Panel 24	Open Circuit	4BS-224K	2.80×10^{-8}	37
Motor Control Center 22	Open Circuit	JBSMC22K	2.80×10^{-8}	37
Motor Control Center 24	Open Circuit	JBSMC24K	2.80×10^{-8}	37
Motor Control Center 26A	Open Circuit	JBSM26AK	2.80×10^{-8}	37
Motor Control Center 26B	Open Circuit	JBSM26BK	2.80×10^{-8}	37
Motor Control Center 29	Open Circuit	JBSMC29K	2.80×10^{-8}	37
Instrument Bus 21	Open Circuit	JBSIB21K	2.80×10^{-8}	37
Instrument Bus 22	Open Circuit	JBSIB22K	2.80×10^{-8}	37
Instrument Bus 23	Open Circuit	JBSIB23K	2.80×10^{-8}	37
Instrument Bus 24	Open Circuit	JBSIB24K	2.80×10^{-8}	37
480V Lighting Bus 22	Open Circuit	JBS4822K	2.80×10^{-8}	37
120V Lighting Bus 21	Open Circuit	JBS1221K	2.80×10^{-8}	37
120V Lighting Bus 22	Open Circuit	JBS1222K	2.80×10^{-8}	37
120V Lighting Bus 23	Open Circuit	JBS1223K	2.80×10^{-8}	37
120 VAC Distribution Panel 21	Open Circuit	JBSDP21K	2.80×10^{-8}	37

Note: Table footnotes (1 through 7) listed on last page of this table.

TABLE 1.5.2.2.1-9 (continued)

INDIAN POINT 2 ELECTRIC POWER FAULT TREE BASIC EVENT DESCRIPTION, COMPONENT FAILURE MODE CODING, AND FAILURE RATES

Component	Failure Mode	Coding	Failure Rate(1)	Reference(2)
120 VAC Distribution Panel 22	Open Circuit	JBSDP22K	2.80×10^{-8}	37
Station Auxiliary Transformer	Open Circuit, Loss of Function	JPTSTAXK	7.63×10^{-7}	32
Station Service Transformer 2	Open Circuit, Loss of Function	JPTSST2K	7.63×10^{-7}	32
Station Service Transformer 3	Open Circuit, Loss of Function	JPTSST3K	7.63×10^{-7}	32
Station Service Transformer 5	Open Circuit, Loss of Function	JPTSST5K	7.63×10^{-7}	32
Station Service Transformer 6	Open Circuit, Loss of Function	JPTSST6K	7.63×10^{-7}	32
480/120V Stepdown Transformer 22	Open Circuit, Loss of Function	JPTSD22K	7.63×10^{-7}	32
480/120V Stepdown Transformer 23	Open Circuit, Loss of Function	JPTSD23K	7.63×10^{-7}	32
480/120V Stepdown Transformer 24	Open Circuit, Loss of Function	JPTSD24K	7.63×10^{-7}	32
Sola Transformer 21	Open Circuit, Loss of Function	JPTST21K	7.63×10^{-7}	32
Sola Transformer 22	Open Circuit, Loss of Function	JPTST22K	7.63×10^{-7}	32
Sola Transformer 23	Open Circuit, Loss of Function	JPTST23K	7.63×10^{-7}	32
Sola Transformer 24	Open Circuit, Loss of Function	JPTST24K	7.63×10^{-7}	32
Lighting Transformer 21	Open Circuit, Loss of Function	JPTLT21K	7.63×10^{-7}	32
Lighting Transformer 22	Open Circuit, Loss of Function	JPTLT22K	7.63×10^{-7}	32
Lighting Transformer 23	Open Circuit, Loss of Function	JPTLT23K	7.63×10^{-7}	32
Circuit Breaker ST5	Transfers open	JCB-ST5B	4.81×10^{-7}	31
Circuit Breaker ST6	Transfers open	JCB-ST6B	4.81×10^{-7}	31
Circuit Breaker SS2	Transfers open	JCB-SS2B	4.81×10^{-7}	31
Circuit Breaker SS3	Transfers open	JCB-SS3B	4.81×10^{-7}	31
Circuit Breaker SS5	Transfers open	JCB-SS5B	4.81×10^{-7}	31

TABLE 1.5.2.2.1-9 (continued)

INDIAN POINT 2 ELECTRIC POWER FAULT TREE BASIC EVENT DESCRIPTION, COMPONENT FAILURE MODE CODING, AND FAILURE RATES

Component	Failure Mode	Coding	Failure Rate(1)	Reference(2)
Circuit Breaker SS6	Transfers Open	JCB-SS6B	4.81×10^{-7}	31
Circuit Breaker 2A	Transfers Open	JCB-22AB	4.81×10^{-7}	31
Circuit Breaker 3A	Transfers Open	JCB-23AB	4.81×10^{-7}	31
Circuit Breaker 5A	Transfers Open	JCB-25AB	4.81×10^{-7}	31
Circuit Breaker 6A	Transfers Open	JCB-26AB	4.81×10^{-7}	31
Battery Charger 21 Supply Breaker	Transfers Open	JCB2921B	4.81×10^{-7}	31
Battery Charger 22 Supply Breaker	Transfers Open	JCB2422B	4.81×10^{-7}	31
Battery Charger 23 Supply Breaker	Transfers Open	JCB2223B	4.81×10^{-7}	31
Battery Charger 24 Supply Breaker	Transfers Open	JCB6B246	4.81×10^{-7}	31
Supply Breaker to MCC 22	Transfers Open	JCBMCC2B	4.81×10^{-7}	31
Supply Breaker to MCC 24	Transfers Open	JCBMCC4B	4.81×10^{-7}	31
Supply Breaker to MCC 26A	Transfers Open	JCBMC6AB	4.81×10^{-7}	31
Supply Breaker to MCC 26B	Transfers Open	JCBMC6BB	4.81×10^{-7}	31
Supply Breaker to MCC 29	Transfers Open	JCBMCC9B	4.81×10^{-7}	31
Supply Breaker to Sola Transformer 21	Transfers Open	JCBSD21B	4.81×10^{-7}	31
Supply Breaker to Sola Transformer 22	Transfers Open	JCBSD22B	4.81×10^{-7}	31
Supply Breaker to Sola Transformer 23	Transfers Open	JCBSD23B	4.81×10^{-7}	31
Supply Breaker to Sola Transformer 24	Transfers Open	JCBSD24B	4.81×10^{-7}	31
Supply Breaker to Lighting Transformer 22	Transfers Open	JCB LT2B	4.81×10^{-7}	31
Supply Breaker to Lighting Transformer 23	Transfers Open	JCB LT3B	4.81×10^{-7}	31
Supply Breaker to 120 VAC Lighting Bus 21	Transfers Open	JCBLB21B	4.81×10^{-7}	31
Supply Breaker to 120 VAC Lighting Bus 22	Transfers Open	JCBLB22B	4.81×10^{-7}	31
Supply Breaker to 120 VAC Lighting Bus 23	Transfers Open	JCBLB23B	4.81×10^{-7}	31

TABLE 1.5.2.2.1-9 (continued)

INDIAN POINT 2 ELECTRIC POWER FAULT TREE BASIC EVENT DESCRIPTION, COMPONENT FAILURE MODE CODING, AND FAILURE RATES

Component	Failure Mode	Coding	Failure Rate(1)	Reference(2)
Supply Breaker to 120 VAC Distribution Panel 21	Transfers Open	JCBDP21B	4.81×10^{-7}	31
Supply Breaker to 120 VAC Distribution Panel 22	Transfers Open	JCBDP22B	4.81×10^{-7}	31
480V Lighting Bus 22 Normal Supply Breaker	Transfers Open	JCBLT1NB	4.81×10^{-7}	31
480V Lighting Bus 22 Emergency Supply Breaker	Transfers Open	JCBLT1EB	4.81×10^{-7}	31
Battery 23 Output Breaker	Transfers Open	4CBBY23B	4.81×10^{-7}	31
Battery 24 Output Breaker	Transfers Open	4CBBY24B	4.81×10^{-7}	31
DC Supply Breaker to Inverter 21	Transfers Open	4CBNV21B	4.81×10^{-7}	31
DC Supply Breaker to Inverter 22	Transfers Open	4CBNV22B	4.81×10^{-7}	31
DC Supply Breaker to Inverter 23	Transfers Open	4CBNV23B	4.81×10^{-7}	31
DC Supply Breaker to Inverter 24	Transfers Open	4CBNV24B	4.81×10^{-7}	31
Circuit Breaker U2S5	Fails to Close on Demand	JCBU2S5X	2.46×10^{-5}*	29
Circuit Breaker U3S6	Fails to Close on Demand	JCBU2S6X	2.46×10^{-5}*	29
Circuit Breaker EG1	Fails to Close on Demand	JCB EG1X	2.46×10^{-5}*	29
Circuit Breaker EG2A	Fails to Close on Demand	JCBEG2AX	2.46×10^{-5}*	29
Circuit Breaker EG2B	Fails to Close on Demand	JCBEG2BX	2.46×10^{-5}*	29
Circuit Breaker EG3	Fails to Close on Demand	JCB EG3X	2.46×10^{-5}*	29
Circuit Breaker GT-25	Fails to Close	JCB GT5X	1.00*	(3)
Circuit Breaker GT-26	Fails to Close	JCB GT6X	1.00*	(3)
Circuit Breaker 2AT3A	Fails to Close	JCB2A3AX	1.00*	(3)
Circuit Breaker 2AT5A	Fails to Close	JCB2A5AX	1.00*	(3)
Circuit Breaker 3AT6A	Fails to Close	JCB3A6AX	1.00*	(3)
DC Power Panels 21 and 22 Crosstie	Fails to Close	4CB2122X	1.00*	(3)
Supply Breaker to MCC 22	Fails to Close (if open)	JCBMCC2X	1.00*	(3)
Supply Breaker to MCC 24	Fails to Close (if open)	JCBMCC4X	1.00*	(3)
Supply Breaker to MCC 29	Fails to Close (if open)	JCBMCC9X	1.00*	(3)

TABLE 1.5.2.2.1-9 (continued)

INDIAN POINT 2 ELECTRIC POWER FAULT TREE BASIC EVENT DESCRIPTION, COMPONENT FAILURE MODE CODING, AND FAILURE RATES

Component	Failure Mode	Coding	Failure Rate(1)	Reference(2)
120 VAC Lighting Buses 22 and 23	Fails to Close Pressure	JCBLBXTX	1.00* Failure Rate	(3)
Gas Turbine Unit 1	Fails to Supply Power	JGEGASTS	1.00*	(4)
Diesel Generator 21	Fails to Start and Load	XDLDG21N	1.29×10^{-2}	27
Diesel Generator 22	Fails to Start and Load	XDLDG22N	1.29×10^{-2}	27
Diesel Generator 23	Fails to Start and Load	XDLDG23N	1.29×10^{-2}	27
Diesel Generator 21 Starting Air	Insufficient Air Supply Pressure	XCRDG21S	Included in Diesel Generator Failure Rate	
Diesel Generator 22 Starting Air	Insufficient Air Supply Pressure	XCRDG22S	Included in Diesel Generator Failure Rate	
Diesel Generator 23 Starting Air	Insufficient Air Supply Pressure	XCRDG23S	Included in Diesel Generator Failure Rate	
Battery 21 Output Fuse	Opens Below Rating	4FUBY21K	8.32×10^{-7}	46
Battery 21 Output Fuse	Opens Below Rating	4FUBY21K	8.32×10^{-7}	46
Battery 21	Failure (no output)	4BY-221D	8.21×10^{-8}	34
Battery 22	Failure (no output)	4BY-222D	8.21×10^{-8}	34
Battery 23	Failure (no output)	4BY-223D	8.21×10^{-8}	34
Battery 24	Failure (no output)	4BY-224D	8.21×10^{-8}	34
Battery Charger 21	Failure (no output)	4BC-221S	2.01×10^{-6}	35
Battery Charger 22	Failure (no output)	4BC-222S	2.01×10^{-6}	35
Battery Charger 23	Failure (no output)	4BC-223S	2.01×10^{-6}	35
Battery Charger 24	Failure (no output)	4BC-224S	2.01×10^{-6}	35
Static Inverter 21	Failure (no output)	JIVSI21S	1.55×10^{-5}	33
Static Inverter 22	Failure (no output)	JIVSI22S	1.55×10^{-5}	33
Static Inverter 23	Failure (no output)	JIVSI23S	1.55×10^{-5}	33
Static Inverter 24	Failure (no output)	JIVSI24S	1.55×10^{-5}	33
Bus 2A DC Transfer Switch	Fails to Transfer	4SSBS2AX	2.71×10^{-6}*	36

TABLE 1.5.2.2.1-9 (continued)

INDIAN POINT 2 ELECTRIC POWER FAULT TREE BASIC EVENT DESCRIPTION, COMPONENT FAILURE MODE CODING, AND FAILURE RATES

Component	Failure Mode	Coding	Failure Rate(1)	Reference(2)
Bus 3A DC Transfer Switch	Fails to Transfer	4SSBS3AX	2.71×10^{-6}*	36
Bus 5A DC Transfer Switch	Fails to Transfer	4SSBS5AX	2.71×10^{-6}*	36
Bus 6A DC Transfer Switch	Fails to Transfer	4SSBS6AX	2.71×10^{-6}*	36
Diesel Generator 21 DC Transfer Switch	Fails to Transfer	4SSDG21X	2.71×10^{-6}*	36
Diesel Generator 22 DC Transfer Switch	Fails to Transfer	4SSDG22X	2.71×10^{-6}*	36
Diesel Generator 23 DC Transfer Switch	Fails to Transfer	4SSDG23X	2.71×10^{-6}*	36
Inverter 21 Bypass Switch	Transfer Open (open circuit)	JSSBP21B	ε	38
Inverter 22 Bypass Switch	Transfer Open (open circuit)	JSSBP22B	ε	38
Inverter 23 Bypass Switch	Transfer Open (open circuit)	JSSBP23B	ε	38
Inverter 24 Bypass Switch	Transfer Open (open circuit)	JSSBP24B	ε	38
Inverter 21 Bypass Switch	Failure to Bypass Inverter	JSSBP21S	1.00*	(5)
Inverter 22 Bypass Switch	Failure to Bypass Inverter	JSSBP22S	1.00*	(5)
Inverter 23 Bypass Switch	Failure to Bypass Inverter	JSSBP23S	1.00*	(5)
Inverter 24 Bypass Switch	Failure to Bypass Inverter	JSSBP24S	1.00*	(5)
Inverter 21 Static Transfer Switch	Transfers Open (open circuit)	JSSST21B	ε	38
Inverter 22 Static Transfer Switch	Transfers Open (open circuit)	JSSST22B	ε	38
Inverter 23 Static Transfer Switch	Transfers Open (open circuit)	JSSST23B	ε	38
Inverter 24 Static Transfer Switch	Transfers Open (open circuit)	JSSST24B	ε	38
480V Lighting Bus 22 Transfer Switch	Failure to Transfer	JSSTS22S	2.71×10^{-6}*	36
480V Lighting Bus 22 Transfer Switch	Transfers Open (open circuit)	JSSTS22B	ε	38

ε = insignificant contribution to failure.

TABLE 1.5.2.2.1-9 (continued)

INDIAN POINT 2 ELECTRIC POWER FAULT TREE BASIC EVENT DESCRIPTION, COMPONENT FAILURE MODE CODING, AND FAILURE RATES

Component	Failure Mode	Coding	Failure Rate(1)	Reference(2)
Circuit Breaker U2S5	Failure of Closing Signal	JREU2S5S	Included in Breaker Failure Rate	
Circuit Breaker U3S6	Failure of Closing Signal	JREU3S6S	Included in Breaker Failure Rate	
Circuit Breaker EG1	Failure of Closing Signal	JRE-EG1S	Determined by Boundary Conditions	
Circuit Breaker EG2A	Failure of Closing Signal	JREEG2AS	Determined by Boundary Conditions	
Circuit Breaker EG2B	Failure of Closing Signal	JREEG2BS	Determined by Boundary Conditions	
Circuit Breaker EG3	Failure of Closing Signal	JRE-EG3S	Determined by Boundary Conditions	
Offsite Power Supply	Failure (no offsite power)	JSHOSPSD	Determined by Boundary Conditions	
Offsite Power Supply	Failure (no offsite power)	JSHOSPSD	Determined by Boundary Conditions	
Diesel Generator 21	Failure of Safety Injection Signal	MRESIS1S	Determined by Boundary Conditions	
Diesel Generator 22	Failure of Safety Injection Signal	MRESIS2S	Determined by Boundary Conditions	
Diesel Generator 23	Failure of Safety Injection signal	MRESIS3S	Determined by Boundary Conditions	

TABLE 1.5.2.2.1-9 (continued)

INDIAN POINT 2 ELECTRIC POWER FAULT TREE BASIC EVENT DESCRIPTION, COMPONENT FAILURE MODE CODING, AND FAILURE RATES

Component	Failure Mode	Coding	Failure Rate	Reference
Diesel Generator 21	Failure of undervoltage Signal	JBSUV21S	Included in Diesel Generator Failure	
Diesel Generator 22	Failure of undervoltage Signal	JBSUV22S	Included in Diesel Generator Failure	
Diesel Generator 23	Failure of undervoltage Signal	JBSUV22S	Included in Diesel Generator Failure	
Diesel Generator 21	Starting Selector Switch in "Auto"	XSSSEL1K	0.00	(6)
Diesel Generator 22	Starting Selector Switch in "Auto"	XSSSEL2K	0.00	
Diesel Generator 23	Starting Selector Switch in "Auto"	XSSSEL3K	0.00	
Supply Breaker to MCC 22	Receives Signal to Open	JREMCC2D	Determined by Boundary Conditions	
Supply Breaker to MCC 24	Receives Signal to Open	JREMCC4D	Determined by Boundary Conditions	
Supply Breaker to MCC 29	Receives Signal to Open	JREMCC9D	Determined by Boundary Conditions	
Inverter 21 Bypass Switch	Switch in "Off" Position	JSSBS21K	0.00	(6)
Inverter 22 Bypass Switch	Switch in "Off" Position	JSSBS22K	0.00	(6)
Inverter 23 Bypass Switch	Switch in "Off" Position	JSSBS23K	0.00	(6)
Inverter 24 Bypass Switch	Switch in "Off" Position	JSSBS24K	0.00	(6)
Diesel Generator 21	Fails During Operation	XDLDG21N(7)	9.37×10^{-4}	28
Diesel Generator 22	Fails During Operation	XDLDG22N	9.37×10^{-4}	28
Diesel Generator 23	Fails During Operation	XDLDG23N	9.37×10^{-4}	28

(1) All failure rates shown are failure rates per hour, except those marked with an asterisk (*), which are failure rates per demand.
(2) All failure data obtained from Table 1.5.1-4 in Section 1.5.1 to this report. The number listed corresponds to the specific item number presented in Table 1.5.1-4.
(3) Circuit breaker requires manual operator action to close and is considered to remain open for hardware failure quantification.
(4) Operator must manually start and load gas turbine unit.
(5) Bypass switch requires manual operator action to transfer and is considered to remain in normal position for hardware failure quantification.
(6) This failure rate is determined by human interactions during testing and maintenance and is considered to be in the unfailed state for hardware failure quantification.
(7) Failure to start on demand and failure during operation combined in a single code to reduce number of cutsets generated.

TABLE 1.5.2.2.1-10A

INDIAN POINT 2 FAILURE OF POWER AT BUS 2A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Unavailability on demand (at event initiation):

  Mean: 1.29×10^{-2}
  Variance: 3.12×10^{-5}

- Dominant failure contributors:

  Diesel generator 22 failure to start on demand:

  Mean: 1.29×10^{-2}
  Variance: 4.15×10^{-5}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22: 1.00
- Diesel generator 23: No effect

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at bus 2A with diesel generator 22 inoperable yields:

  Testing contribution to unavailability (Q_T):

  Mean: 2.51×10^{-5}
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-10A (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUS 2A -
OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

  Applying this to the conditional unavailability of power at bus 2A with diesel generator 22 inoperable yields:

  Maintenance contribution to unavailability (Q_M):

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generator 22 due to fuel oil supply failure:

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

  Applying this to the conditional unavailability of power at bus 2A with diesel generator 22 inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

TABLE 1.5.2.2.1-10B

INDIAN POINT 2 FAILURE OF POWER AT BUS 3A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failure
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Unavailability on demand (at event initiation):

  Mean: 1.29×10^{-2}
  Variance: 3.12×10^{-5}

- Dominant failure contributors:

  Diesel generator 22 failure to start on demand

  Mean: 1.29×10^{-2}
  Variance: 4.15×10^{-5}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22: 1.00
- Diesel generator 23: No effect

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

Applying this to the conditional unavailability of power at bus 3A with diesel generator 22 inoperable yields:

Testing contribution to unavailability (Q_T):

Mean: 2.51×10^{-5}
Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-10B (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUS 3A -
OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

  Applying this to the conditional unavailability of power at bus 3A with diesel generator 22 inoperable yields:

  Maintenance contribution to unavailability (Q_M):

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generator 22 due to fuel oil supply failure:

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

  Applying this to the conditional unavailability of power at bus 3A with diesel generator 22 inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

TABLE 1.5.2.2.1-10C

INDIAN POINT 2 FAILURE OF POWER AT BUS 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Unavailability on demand (at event initiation):

  Mean: 1.29×10^{-2}
  Variance: 3.12×10^{-5}

- Dominant failure contributors:

  Diesel generator 21 failure to start on demand

  Mean: 1.29×10^{-2}
  Variance: 4.15×10^{-5}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: 1.00
- Diesel generator 22: No effect
- Diesel generator 23: No effect

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at bus 5A with diesel generator 21 inoperable yields:

  Testing contribution to unavailability (Q_T):

  Mean: 2.51×10^{-5}
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-10C (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUS 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

  Applying this to the conditional unavailability of power at bus 5A with diesel generator 21 inoperable yields:

  Maintenance contribution to unavailability (Q_M):

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generator 21 due to fuel oil supply failure:

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

  Applying this to the conditional unavailability of power at bus 5A with diesel generator 21 inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

TABLE 1.5.2.2.1-10D

INDIAN POINT 2 FAILURE OF POWER AT BUS 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Unavailability on demand (at event initiation):

  Mean: 1.29×10^{-2}
  Variance: 3.12×10^{-5}

- Dominant failure contributors:

  Diesel generator 23 failure to start on demand

  Mean: 1.29×10^{-2}
  Variance: 4.15×10^{-5}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22: No effect
- Diesel generator 23: 1.00

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at bus 6A with diesel generator 23 inoperable yields:

  Testing contribution to unavailability (Q_T):

  Mean: 2.51×10^{-5}
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-10D (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUS 6A -
OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

  Applying this to the conditional unavailability of power at bus 6A with diesel generator 23 inoperable yields:

  Maintenance contribution to unavailability (Q_M):

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generator 23 due to fuel oil supply failure:

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

  Applying this to the conditional unavailability of power at bus 6A with diesel generator 23 inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

TABLE 1.5.2.2.1-10E

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 3A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Unavailability on demand (at event initiation):

  Mean: 1.29×10^{-2}
  Variance: 3.12×10^{-5}

- Dominant failure contributors:

  Diesel generator 22 failure to start on demand

  Mean: 1.29×10^{-2}
  Variance: 4.15×10^{-5}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22: 1.00
- Diesel generator 23: No effect

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A and 3A with diesel generator 22 inoperable yields:

  Testing contribution to unavailability (Q_T):

  Mean: 2.51×10^{-5}
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-10E (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 3A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

  Applying this to the conditional unavailability of power at buses 2A and 3A with diesel generator 22 inoperable yields:

  Maintenance contribution to unavailability (Q_M):

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generator 22 due to fuel oil supply failure:

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

  Applying this to the conditional unavailability of power at buses 2A and 3A with diesel generator 22 inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 2.43×10^{-5}
  Variance: 4.89×10^{-10}

TABLE 1.5.2.2.1-10F

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Unavailability on demand (at event initiation):

  Mean: 1.98×10^{-4}
  Variance: 2.70×10^{-8}

- Dominant failure contributors:

  Diesel generators 21 and 22 fail to start on demand:

  Mean: 1.98×10^{-4}
  Variance: 2.69×10^{-8}

  Diesel generators 21 and 22 fail during operation for 6 hours:

  Mean: 6.77×10^{-5}
  Variance: 1.21×10^{-8}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 23: No effect
- Diesel generators 21 and 22: 1.00

TABLE 1.5.2.2.1-10F (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

  Mean: 9.29×10^{-7}
  Variance: 3.61×10^{-12}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A and 5A with diesel generator 21 and diesel generator 22 inoperable yields:

  Mean: 2.03×10^{-6}
  Variance: 2.34×10^{-11}

- Testing contribution to unavailability (Q_T):

  Mean: 2.96×10^{-6}
  Variance: 1.60×10^{-11}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-10F (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 1.12×10^{-3}
Variance: 1.89×10^{-7}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 21 and 22 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 2A and 5A with diesel generators 21 and 22 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

TABLE 1.5.2.2.1-10G

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Unavailability on demand (at event initiation):

  Mean: 1.98×10^{-4}
  Variance: 2.70×10^{-8}

- Dominant failure contributors:

  Diesel generators 22 and 23 fail to start on demand:

  Mean: 1.98×10^{-4}
  Variance: 2.69×10^{-8}

  Diesel generators 22 and 23 fail during operation for 6 hours:

  Mean: 6.77×10^{-5}
  Variance: 1.21×10^{-8}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 22 and 23: 1.00

TABLE 1.5.2.2.1-10G (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

  Mean: 9.29×10^{-7}
  Variance: 3.61×10^{-12}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A and 6A with diesel generator 22 and diesel generator 23 inoperable yields:

  Mean: 2.03×10^{-6}
  Variance: 2.34×10^{-11}

- Testing contribution to unavailability (Q_T):

  Mean: 2.96×10^{-6}
  Variance: 1.60×10^{-11}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-10G (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 1.12×10^{-3}
Variance: 1.89×10^{-7}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 22 and 23 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 2A and 6A with diesel generators 22 and 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

TABLE 1.5.2.2.1-10H

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Unavailability on demand (at event initiation):

  Mean: 1.98×10^{-4}
  Variance: 2.70×10^{-8}

- Dominant failure contributors:

  Diesel generators 21 and 22 fail to start on demand:

  Mean: 1.98×10^{-4}
  Variance: 2.69×10^{-8}

  Diesel generators 21 and 22 fail during operation for 6 hours:

  Mean: 6.77×10^{-5}
  Variance: 1.21×10^{-8}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 23: No effect
- Diesel generators 21 and 22: 1.00

TABLE 1.5.2.2.1-10H (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 3A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

  Mean: 9.29×10^{-7}
  Variance: 3.61×10^{-12}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 3A and 5A with diesel generator 22 and diesel generator 23 inoperable yields:

  Mean: 2.03×10^{-6}
  Variance: 2.34×10^{-11}

- Testing contribution to unavailability (Q_T):

  Mean: 2.96×10^{-6}
  Variance: 1.60×10^{-11}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-10H (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 5A -
OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 3A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 1.12×10^{-3}
Variance: 1.89×10^{-7}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 21 and 22 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 3A and 5A with diesel generators 21 and 22 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

TABLE 1.5.2.2.1-10I

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Unavailability on demand (at event initiation):

  Mean: 1.98×10^{-4}
  Variance: 2.70×10^{-8}

- Dominant failure contributors:

  Diesel generators 22 and 23 fail to start on demand:

  Mean: 1.98×10^{-4}
  Variance: 1.69×10^{-8}

  Diesel generators 22 and 23 fail during operation for 6 hours:

  Mean: 6.77×10^{-5}
  Variance: 1.21×10^{-8}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 22 and 23: 1.00

TABLE 1.5.2.2.1-10I (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 3A and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

  Mean: 9.29×10^{-7}
  Variance: 3.61×10^{-12}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 3A and 6A with diesel generator 22 and diesel generator 23 inoperable yields:

  Mean: 2.03×10^{-6}
  Variance: 2.34×10^{-11}

- Testing contribution to unavailability (Q_T):

  Mean: 2.96×10^{-6}
  Variance: 1.60×10^{-11}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-10I (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 3A and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 1.12×10^{-3}
Variance: 1.89×10^{-7}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 22 and 23 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 3A and 6A with diesel generators 22 and 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

TABLE 1.5.2.2.1-10J

INDIAN POINT 2 FAILURE OF POWER AT BUSES 5A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Unavailability on demand (at event initiation):

  Mean: 1.98×10^{-4}
  Variance: 2.70×10^{-8}

- Dominant failure contributors:

  Failure of diesel generators 21 and 23 to start on demand:

  Mean: 1.98×10^{-4}
  Variance: 2.69×10^{-8}

  Failue of diesel generators 21 and 23 during operation for 6 hours:

  Mean: 6.77×10^{-2}
  Variance: 1.21×10^{-8}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 22: No effect
- Diesel generator 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 21 and 22: 1.00

TABLE 1.5.2.2.1-10J (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 5A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 5A and 6A with diesel generator 21 or diesel generator 23 inoperable yields:

  Mean: 9.29×10^{-7}
  Variance: 3.61×10^{-12}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 5A and 6A with diesel generator 21 and diesel generator 23 inoperable yields:

  Mean: 2.03×10^{-6}
  Variance: 2.34×10^{-11}

- Testing contribution to unavailability (Q_T):

  Mean: 2.96×10^{-6}
  Variance: 1.60×10^{-11}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-10J (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 5A AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 5A and 6A with diesel generator 21 or diesel generator 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 1.12×10^{-3}
Variance: 1.89×10^{-7}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 21 and 23 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 5A and 6A with diesel generators 21 and 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

TABLE 1.5.2.2.1-10K

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Unavailability on demand (at event initiation):

  Mean: 1.98×10^{-4}
  Variance: 2.70×10^{-8}

- Dominant failure contributors:

  Failure of diesel generators 21 and 22 to start on demand:

  Mean: 1.98×10^{-4}
  Variance: 2.69×10^{-8}

  Failure of diesel generators 21 and 22 during operation for 6 hours:

  Mean: 6.77×10^{-5}
  Variance: 1.21×10^{-8}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 23: No effect
- Diesel generators 21 and 22: 1.00

TABLE 1.5.2.2.1-10K (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A, 3A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

  Mean: 9.29×10^{-7}
  Variance: 3.61×10^{-12}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A, 3A and 5A with diesel generator 21 and diesel generator 22 inoperable yields:

  Mean: 2.03×10^{-6}
  Variance: 2.34×10^{-11}

- Testing contribution to unavailability (Q_T):

  Mean: 2.96×10^{-6}
  Variance: 1.60×10^{-11}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-10K (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 5A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A, 3A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 1.12×10^{-3}
Variance: 1.89×10^{-7}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 21 and 22 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 2A, 3A, and 5A with diesel generators 21 and 22 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

TABLE 1.5.2.2.1-10L

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Unavailability on demand (at event initiation):

  Mean: 1.98×10^{-4}
  Variance: 2.70×10^{-8}

- Dominant failure contributors:

  Failure of diesel generators 22 and 23 to start on demand:

  Mean: 1.98×10^{-4}
  Variance: 2.69×10^{-8}

  Failure of diesel generators 22 and 23 during operation for 6 hours:

  Mean: 6.77×10^{-5}
  Variance: 1.21×10^{-8}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect

- Diesel generator 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generator 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 22 and 23: 1.00

TABLE 1.5.2.2.1-10L (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A, 3A, and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

  Mean: 9.29×10^{-7}
  Variance: 3.61×10^{-12}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A, 3A, and 6A with diesel generator 22 and diesel generator 23 inoperable yields:

  Mean: 2.03×10^{-6}
  Variance: 2.34×10^{-11}

- Testing contribution to unavailability (Q_T):

  Mean: 2.96×10^{-6}
  Variance: 1.60×10^{-11}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-10L (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A, 3A, and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 1.12×10^{-3}
Variance: 1.89×10^{-7}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 22 and 23 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 2A, 3A, and 6A with diesel generators 22 and 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

TABLE 1.5.2.2.1-10M

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 5A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.04×10^{-5}
  Variance: 1.68×10^{-10}

- Unavailability on demand (at event initiation):

  Mean: 3.47×10^{-6}
  Variance: 1.61×10^{-11}

- Dominant failure contributors:

  Failure of diesel generators 21, 22, and 23 to start on demand:

  Mean: 3.45×10^{-6}
  Variance: 1.60×10^{-11}

  Failure of diesel generators 21, 22, and 23 during operation for 6 hours:

  Mean: 1.04×10^{-6}
  Variance: 3.33×10^{-12}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Diesel generator 22:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Diesel generator 23:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

TABLE 1.5.2.2.1-10M (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 5A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

- Diesel generators 21 and 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 21 and 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 22 and 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- All three diesel generators: 1.00

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with diesel generator 21, 22, or 23 inoperable yields:

  Mean: 3.08×10^{-8}
  Variance: 4.19×10^{-15}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with each combination of two diesel generators inoperable yields:

  Mean: 1.13×10^{-7}
  Variance: 3.72×10^{-14}

TABLE 1.5.2.2.1-10M (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 5A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

- From Section 1.5.2.2.1.4.2, unavailability of three diesel generators due to testing errors:

  Mean: $Q_{TE3} = 1.63 \times 10^{-7}$
  Variance: 2.02×10^{-13}

  Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with al three diesel generators inoperable yields:

  Mean: 1.63×10^{-7}
  Variance: 2.02×10^{-13}

- Testing contribution to unavailability (Q_T):

  Mean: 3.06×10^{-7}
  Variance: 1.33×10^{-13}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

  Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with diesel generator 21, 22, or 23 inoperable yields:

  Maintenance contribution to unavailability (Q_M):

  Mean: 3.70×10^{-5}
  Variance: 3.74×10^{-10}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 21, 22 and 23 due to fuel oil supply failure:

  Mean: 3.49×10^{-5}
  Variance: 7.51×10^{-10}

TABLE 1.5.2.2.1-10M (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 5A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A, 5A and 6A with all three diesel generators inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.49×10^{-5}
Variance: 7.51×10^{-10}

TABLE 1.5.2.2.1-10N

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A, 5A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.04×10^{-5}
  Variance: 1.68×10^{-10}

- Unavailability on demand (at event initiation):

  Mean: 3.47×10^{-6}
  Variance: 1.61×10^{-11}

- Dominant failure contributors:

  Failure of diesel generators 21, 22, and 23 to start on demand:

  Mean: 3.45×10^{-6}
  Variance: 1.60×10^{-11}

  Failure of diesel generators 21, 22, and 23 during operation for 6 hours:

  Mean: 1.04×10^{-6}
  Variance: 3.33×10^{-12}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Diesel generator 22:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Diesel generator 23:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

TABLE 1.5.2.2.1-10N (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A, 5A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

- Diesel generators 21 and 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 21 and 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 22 and 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- All three diesel generators: 1.00

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with diesel generator 21, 22, or 23 inoperable yields:

  Mean: 3.08×10^{-8}
  Variance: 4.19×10^{-15}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with each combination of two diesel generators inoperable yields:

  Mean: 1.13×10^{-7}
  Variance: 3.72×10^{-14}

TABLE 1.5.2.2.1-10N (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A, 5A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

- From Section 1.5.2.2.1.4.2, unavailability of three diesel generators due to testing errors:

  Mean: $Q_{ET3} = 1.63 \times 10^{-7}$
  Variance: 2.02×10^{-13}

  Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with all three diesel generators inoperable yields:

  Mean: 1.63×10^{-7}
  Variance: 2.02×10^{-13}

- Testing contribution to unavailability (Q_T):

  Mean: 3.06×10^{-7}
  Variance: 1.33×10^{-13}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

  Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with diesel generator 21, 22, or 23 inoperable yields:

  Maintenance contribution to unavailability (Q_M):

  Mean: 3.70×10^{-5}
  Variance: 3.74×10^{-10}

TABLE 1.5.2.2.1-10N (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A, 5A, AND 6A - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 21, 22, and 23 due to fuel oil supply failure:

  Mean: 3.49×10^{-5}
  Variance: 7.51×10^{-10}

  Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with all three diesel generators inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 3.49×10^{-5}
  Variance: 7.51×10^{-10}

TABLE 1.5.2.2.1-100

INDIAN POINT 2 FAILURE OF POWER AT ALL 480V BUSES - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.04×10^{-5}
  Variance: 1.67×10^{-10}

- Unavailability on demand (at event initiation):

  Mean: 3.46×10^{-6}
  Variance: 1.61×10^{-11}

- Dominant failure contributors:

  Failure of all three diesel generators to start on demand:

  Mean: 3.45×10^{-6}
  Variance: 1.60×10^{-11}

  Failure of all three diesel generators during operation for 6 hours:

  Mean: 1.04×10^{-6}
  Variance: 3.33×10^{-12}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Diesel generator 22:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Diesel generator 23:

  Mean: 4.09×10^{-4}
  Variance: 1.21×10^{-7}

- Diesel generators 21 and 22:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

TABLE 1.5.2.2.1-100 (continued)

INDIAN POINT 2 FAILURE OF POWER AT ALL 480V BUSES - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

- Diesel generators 21 and 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- Diesel generators 22 and 23:

  Mean: 1.85×10^{-2}
  Variance: 6.64×10^{-5}

- All three diesel generators: 1.00

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at all four buses with each of the diesel generators inoperable yields:

  Mean: 3.08×10^{-8}
  Variance: 4.19×10^{-15}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at all four buses with each combination of two diesel generators inoperable yields:

  Mean: 1.13×10^{-7}
  Variance: 3.72×10^{-14}

- From Section 1.5.2.2.1.4.2, unavailability of three diesel generators due to testing errors:

  Mean: $Q_{ET3} = 1.63 \times 10^{-7}$
  Variance: 2.02×10^{-13}

TABLE 1.5.2.2.1-100 (continued)

INDIAN POINT 2 FAILURE OF POWER AT ALL 480V BUSES - OFFSITE POWER NOT AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at all four buses with all three diesel generators inoperable yields:

Mean: 1.63×10^{-7}
Variance: 2.02×10^{-13}

- Testing contribution to unavailability (Q_T):

Mean: 3.06×10^{-7}
Variance: 1.33×10^{-13}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at all four buses with each of the diesel generators inoperable yields:

- Maintenance contribution to unavailability (Q_M):

Mean: 3.70×10^{-5}
Variance: 3.74×10^{-10}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.1, unavailability of diesel generators 21, 22, and 23 due to fuel oil supply failure:

Mean: 3.49×10^{-5}
Variance: 7.51×10^{-10}

Applying this to the conditional unavailability of power at all four buses with all three diesel generators inoperable yields:

- Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 3.49×10^{-5}
Variance: 7.51×10^{-10}

TABLE 1.5.2.2.1-11A

INDIAN POINT 2 FAILURE OF POWER AT BUS 2A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 3.88×10^{-5}
  Variance: 1.34×10^{-9}

- Unavailability on demand (at event initiation):

  Mean: 2.46×10^{-5}
  Variance: 1.84×10^{-8}

- Dominant failure contributors:

  Breaker UT2/ST5 failure to close on demand

  Mean: 2.46×10^{-5}
  Variance: 1.84×10^{-8}

  Transformer SST2 failure over 6 hours:

  Mean: 4.58×10^{-6}
  Variance: 1.81×10^{-11}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect

- Diesel generator 22:

  Mean: 6.99×10^{-5}
  Variance: 2.30×10^{-9}

- Diesel generator 23: No effect

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-11A (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUS 2A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at bus 2A with diesel generator 22 inoperable yields:

Testing contribution to unavailability (Q_T):

Mean: 1.75×10^{-9}
Variance: 1.47×10^{-17}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at bus 2A with diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 2.11×10^{-6}
Variance: 2.18×10^{-12}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generator 22 due to fuel oil supply failure:

Mean: 2.43×10^{-5}
Variance: 4.89×10^{-10}

Applying this to the conditional unavailability of power at bus 2A with diesel generator 22 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 1.70×10^{-9}
Variance: 3.60×10^{-18}

TABLE 1.5.2.2.1-11B

INDIAN POINT 2 FAILURE OF POWER AT BUS 3A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 3.88×10^{-5}
  Variance: 1.34×10^{-9}

- Unavailability on demand (at event initiation):

  Mean: 2.46×10^{-5}
  Variance: 1.84×10^{-8}

- Dominant failure contributors:

  Breaker UT3/ST6 failure to close on demand

  Mean: 2.46×10^{-5}
  Variance: 1.84×10^{-8}

  Transformer SST3 failure over 6 hours:

  Mean: 4.58×10^{-6}
  Variance: 1.81×10^{-11}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22:

  Mean: 6.99×10^{-5}
  Variance: 2.30×10^{-9}

- Diesel generator 23: No effect

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-11B (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUS 3A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at bus 3A with diesel generator 22 inoperable yields:

Testing contribution to unavailability (Q_T):

Mean: 1.75×10^{-9}
Variance: 1.47×10^{-17}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at bus 3A with diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 2.11×10^{-6}
Variance: 2.18×10^{-12}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generator 22 due to fuel oil supply failure:

Mean: 2.43×10^{-5}
Variance: 4.89×10^{-10}

Applying this to the conditional unavailability of power at bus 3A with diesel generator 22 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 1.70×10^{-9}
Variance: 3.60×10^{-18}

TABLE 1.5.2.2.1-11C

INDIAN POINT 2 FAILURE OF POWER AT BUS 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Unavailability on demand (at event initiation): bus 5A remains energized at event initiation.

- Dominant failure contributors:

  Failure of Bus 5A over 6 hours:

  Mean: 1.68×10^{-7}
  Variance: 4.50×10^{-14}

  Failure of one transformer over 6 hours and failure of diesel generator 21 to start on demand:

  Mean: 5.91×10^{-8}
  Variance: 4.24×10^{-15}

  One circuit breaker transfers open over 6 hours and diesel generator 21 fails to start on demand:

  Mean: 3.72×10^{-8}
  Variance: 2.22×10^{-15}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

- Diesel generator 22: No effect
- Diesel generator 23: No effect

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-11C (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUS 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at bus 5A with diesel generator 21 inoperable yields:

Testing contribution to unavailability (Q_T):

Mean: 7.96×10^{-10}
Variance: 3.06×10^{-18}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at bus 5A with diesel generator 21 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 9.57×10^{-7}
Variance: 4.80×10^{-13}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generator 21 due to fuel oil supply failure:

Mean: 2.43×10^{-5}
Variance: 4.89×10^{-10}

Applying this to the conditional unavailability of power at bus 5A with diesel generator 21 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 7.70×10^{-10}
Variance: 7.66×10^{-19}

TABLE 1.5.2.2.1-11D

INDIAN POINT 2 FAILURE OF POWER AT BUS 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Unavailability on demand (at event initiation): bus 6A remains energized at event initiation.

- Dominant failure contributors:

  Failure of bus 6A over 6 hours:

  Mean: 1.68×10^{-7}
  Variance: 4.50×10^{-14}

  Failure of one transformer over 6 hours and failure of diesel generator 23 to start on demand:

  Mean: 5.91×10^{-8}
  Variance: 4.24×10^{-15}

  One circuit breaker transfers open over 6 hours and diesel generator 23 fails to start on demand:

  Mean: 3.72×10^{-8}
  Variance: 2.22×10^{-15}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22: No effect
- Diesel generator 23:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-11D (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUS 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at bus 6A with diesel generator 23 inoperable yields:

Testing contribution to unavailability (Q_T):

Mean: 7.96×10^{-10}
Variance: 3.06×10^{-18}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at bus 6A with diesel generator 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 9.57×10^{-7}
Variance: 4.80×10^{-13}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generator 23 due to fuel oil supply failure:

Mean: 2.43×10^{-5}
Variance: 4.89×10^{-10}

Applying this to the conditional unavailability of power at bus 6A with diesel generator 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 7.70×10^{-10}
Variance: 7.66×10^{-19}

TABLE 1.5.2.2.1-11E

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 3A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 5.88×10^{-7}
  Variance: 2.72×10^{-13}

- Unavailability on demand (at event initiation):

  Mean: 1.84×10^{-9}
  Variance: 1.05×10^{-17}

- Dominant failure contributors:

  Failure of one transformer over 6 hours and failure of diesel generator 22 to start on demand:

  Mean: 5.91×10^{-8}
  Variance: 4.24×10^{-15}

  One circuit breaker transfers open over 6 hours and diesel generator 22 fails to start on demand:

  Mean: 3.72×10^{-8}
  Variance: 2.22×10^{-15}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22:

  Mean: 3.17×10^{-5}
  Variance: 5.10×10^{-10}

- Diesel generator 23: No effect

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

TABLE 1.5.2.2.1-11E (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 3A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A and 3A with diesel generator 22 inoperable yields:

Testing contribution to unavailability (Q_T):

Mean: 7.96×10^{-10}
Variance: 3.06×10^{-18}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at buses 2A and 3A with diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 9.57×10^{-7}
Variance: 4.77×10^{-13}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generator 22 due to fuel oil supply failure:

Mean: 2.43×10^{-5}
Variance: 4.89×10^{-10}

Applying this to the conditional unavailability of power at buses 2A and 3A with diesel generator 22 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 7.70×10^{-10}
Variance: 7.63×10^{-19}

TABLE 1.5.2.2.1-11F

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.60×10^{-8}
  Variance: 3.06×10^{-16}

- Unavailability on demand (at event initiation): bus 5A remains energized at event initiation.

- Dominant failure contributors:

  Bus 5A fails over 6 hours and diesel generator 22 fails to start on demand:

  Mean: 2.17×10^{-9}
  Variance: 9.78×10^{-18}

  Failure of one transformer over 6 hours and failure of diesel generators 21, 22, and 23 to start on demand:

  Mean: 9.05×10^{-10}
  Variance: 1.76×10^{-18}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 5.86×10^{-7}
  Variance: 2.72×10^{-13}

- Diesel generator 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generator 23: No effect

- Diesel generators 21 and 22:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

TABLE 1.5.2.2.1-11F (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

  Mean: 3.36×10^{-11}
  Variance: 5.08×10^{-21}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A and 5A with diesel generator 21 and diesel generator 22 inoperable yields:

  Mean: 6.44×10^{-11}
  Variance: 1.52×10^{-20}

- Testing contribution to unavailability (Q_T):

  Mean: 9.79×10^{-11}
  Variance: 1.98×10^{-20}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-11F (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 4.04×10^{-8}
Variance: 5.81×10^{-16}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 21 and 22 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 2A and 5A with diesel generators 21 and 22 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 9.54×10^{-10}
Variance: 1.05×10^{-18}

TABLE 1.5.2.2.1-11G

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.60×10^{-8}
  Variance: 3.06×10^{-16}

- Unavailability on demand (at event initiation): bus 6A remains energized at event initiation.

- Dominant failure contributors:

  Bus 6A fails over 6 hours and diesel generator 22 fails to start on demand:

  Mean: 2.17×10^{-9}
  Variance: 9.78×10^{-18}

  Failure of one transformer over 6 hours and failure of diesel generators 22 and 23 to start on demand:

  Mean: 9.05×10^{-10}
  Variance: 1.76×10^{-18}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect

- Diesel generator 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generator 23:

  Mean: 5.86×10^{-7}
  Variance: 2.72×10^{-13}

- Diesel generators 22 and 23:

  Mean: 3.17×10^{-6}
  Variance: 5.14×10^{-10}

TABLE 1.5.2.2.1-11G (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

  Mean: 3.36×10^{-11}
  Variance: 5.08×10^{-21}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A and 6A with diesel generator 22 and diesel generator 23 inoperable yields:

  Mean: 6.44×10^{-11}
  Variance: 1.52×10^{-20}

- Testing contribution to unavailability (Q_T):

  Mean: 9.79×10^{-11}
  Variance: 1.98×10^{-20}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-11G (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 4.04×10^{-8}
Variance: 5.81×10^{-16}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 22 and 23 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 2A and 6A with diesel generators 22 and 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 9.54×10^{-10}
Variance: 1.05×10^{-18}

TABLE 1.5.2.2.1-11H

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.60×10^{-8}
  Variance: 3.06×10^{-16}

- Unavailability on demand (at event initiation): bus 5A remains energized at event initiation.

- Dominant failure contributors:

  Bus 5A fails over 6 hours and diesel generator 22 fails to start on demand:

  Mean: 2.17×10^{-9}
  Variance: 9.78×10^{-18}

  Failure of one transformer over 6 hours and failure of diesel generators 21 and 22 to start on demand:

  Mean: 9.05×10^{-10}
  Variance: 1.76×10^{-18}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 5.86×10^{-7}
  Variance: 2.72×10^{-13}

- Diesel generator 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generator 23: No effect

- Diesel generators 21 and 22:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

TABLE 1.5.2.2.1-11H (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 3A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

  Mean: 3.36×10^{-11}
  Variance: 5.08×10^{-21}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 3A and 5A with diesel generator 21 and diesel generator 22 inoperable yields:

  Mean: 6.44×10^{-11}
  Variance: 1.52×10^{-20}

- Testing contribution to unavailability (Q_T):

  Mean: 9.79×10^{-11}
  Variance: 1.98×10^{-20}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-11H (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 3A and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 4.04×10^{-8}
Variance: 5.81×10^{-16}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 21 and 22 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 3A and 5A with diesel generators 21 and 22 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 9.54×10^{-10}
Variance: 1.05×10^{-18}

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Volume 3

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TABLE 1.5.2.2.1-11I

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.60×10^{-8}
  Variance: 3.06×10^{-16}

- Unavailability on demand (at event initiation): bus 6A remains energized at event initiation.

- Dominant failure contributors:

  Bus 6A fails over 6 hours and diesel generator 22 fails to start on demand:

  Mean: 2.17×10^{-9}
  Variance: 9.78×10^{-18}

  Failure of one transformer over 6 hours and failure of diesel generators 22 and 23 to start on demand:

  Mean: 9.05×10^{-10}
  Variance: 1.76×10^{-18}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generator 23:

  Mean: 5.86×10^{-7}
  Variance: 2.72×10^{-13}

- Diesel generators 22 and 23:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

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TABLE 1.5.2.2.1-11I (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 3A and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

  Mean: 3.36×10^{-11}
  Variance: 5.08×10^{-21}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 3A and 6A with diesel generator 22 and diesel generator 23 inoperable yields:

  Mean: 6.44×10^{-11}
  Variance: 1.52×10^{-20}

- Testing contribution to unavailability (Q_T):

  Mean: 9.79×10^{-11}
  Variance: 1.98×10^{-20}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-11I (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 3A and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 4.04×10^{-8}
Variance: 5.81×10^{-16}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 22 and 23 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 3A and 6A with diesel generators 22 and 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 9.54×10^{-10}
Variance: 1.05×10^{-18}

TABLE 1.5.2.2.1-11J

INDIAN POINT 2 FAILURE OF POWER AT BUSES 5A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.91×10^{-8}
  Variance: 3.94×10^{-16}

- Unavailability on demand (at event initiation): buses 5A and 6A remain energized at event initiation.

- Dominant failure contributors:

  Bus 5A (6A) fails over 6 hours and diesel generator 23 (21) fails to start on demand:

  Mean: 2.17×10^{-9}
  Variance: 9.78×10^{-18}

  Failure of one transformer over 6 hours and failure of diesel generators 21 and 23 to start on demand:

  Mean: 9.05×10^{-10}
  Variance: 1.76×10^{-18}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generator 22: No effect

- Diesel generator 23:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generators 21 and 23:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

TABLE 1.5.2.2.1-11J (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 5A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 5A and 6A with diesel generator 21 or diesel generator 23 inoperable yields:

  Mean: 3.77×10^{-11}
  Variance: 6.43×10^{-21}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 5A and 6A with diesel generator 21 and diesel generator 23 inoperable yields:

  Mean: 6.44×10^{-11}
  Variance: 1.52×10^{-20}

- Testing contribution to unavailability (Q_T):

  Mean: 1.02×10^{-10}
  Variance: 2.09×10^{-20}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

  Applying this to the conditional unavailability of power at buses 5A and 6A with diesel generator 21 or diesel generator 23 inoperable yields:

TABLE 1.5.2.2.1-11J (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 5A AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Maintenance contribution to unavailability (Q_M):

Mean: 4.53×10^{-8}
Variance: 6.50×10^{-16}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 21 and 23 due to fuel oil supply failure:

  Mean: 3.01×10^{-5}
  Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 5A and 6A with diesel generators 21 and 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 9.54×10^{-10}
Variance: 1.05×10^{-18}

TABLE 1.5.2.2.1-11K

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.60×10^{-8}
  Variance: 3.05×10^{-16}

- Unavailability on demand (at event initiation): bus 5A remains energized at event initiation.

- Dominant failure contributors:

  Bus 5A fails over 6 hours and diesel generator 22 fails to start on demand:

  Mean: 2.17×10^{-9}
  Variance: 9.78×10^{-18}

  Failure of one transformer over 6 hours and failure of diesel generators 21 and 22 to start on demand:

  Mean: 9.05×10^{-10}
  Variance: 1.76×10^{-18}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 5.85×10^{-7}
  Variance: 2.71×10^{-13}

- Diesel generator 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generator 23: No effect

- Diesel generators 21 and 22:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

TABLE 1.5.2.2.1-11K (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A, 3A, and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

  Mean: 3.35×10^{-11}
  Variance: 5.07×10^{-21}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A, 3A, and 5A with diesel generator 21 and diesel generator 22 inoperable yields:

  Mean: 6.44×10^{-11}
  Variance: 1.52×10^{-20}

- Testing contribution to unavailability (Q_T):

  Mean: 9.79×10^{-11}
  Variance: 1.98×10^{-20}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-11K (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 5A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A, 3A, and 5A with diesel generator 21 or diesel generator 22 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 4.03×10^{-8}
Variance: 5.80×10^{-16}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 21 and 22 due to fuel oil supply failure:

  Mean: 3.01×10^{-5}
  Variance: 6.09×10^{-10}

  Applying this to the conditional unavailability of power at buses 2A, 3A, and 5A with diesel generators 21 and 22 inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 9.54×10^{-10}
  Variance: 1.05×10^{-18}

TABLE 1.5.2.2.1-11L

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 1.60×10^{-8}
  Variance: 3.05×10^{-16}

- Unavailability on demand (at event initiation): bus 6A remains energized at event initiation.

- Dominant failure contributors:

  Bus 6A fails over 6 hours and diesel generator 22 fails to start on demand:

  Mean: 2.17×10^{-9}
  Variance: 9.78×10^{-18}

  Failure of one transformer over 6 hours and failure of diesel generators 22 and 23 to start on demand:

  Mean: 9.05×10^{-10}
  Variance: 1.76×10^{-18}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21: No effect
- Diesel generator 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generator 23:

  Mean: 5.85×10^{-7}
  Variance: 2.71×10^{-13}

- Diesel generators 22 and 23:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

TABLE 1.5.2.2.1-11L (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A, 3A, and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

  Mean: 3.35×10^{-11}
  Variance: 5.07×10^{-21}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

  Applying this to the conditional unavailability of power at buses 2A, 3A, and 6A with diesel generator 22 and diesel generator 23 inoperable yields:

  Mean: 6.44×10^{-11}
  Variance: 1.52×10^{-20}

- Testing contribution to unavailability (Q_T):

  Mean: 9.79×10^{-11}
  Variance: 1.98×10^{-20}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

  Mean: 3.02×10^{-2}
  Variance: 5.44×10^{-5}

TABLE 1.5.2.2.1-11L (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 3A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A, 3A, and 6A with diesel generator 22 or diesel generator 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 4.03×10^{-8}
Variance: 5.80×10^{-16}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 22 and 23 due to fuel oil supply failure:

Mean: 3.01×10^{-5}
Variance: 6.09×10^{-10}

Applying this to the conditional unavailability of power at buses 2A, 3A, and 6A with diesel generators 22 and 23 inoperable yields:

Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

Mean: 9.54×10^{-10}
Variance: 1.05×10^{-18}

TABLE 1.5.2.2.1-11M

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 5A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.64×10^{-10}
  Variance: 4.35×10^{-19}

- Unavailability on demand (at event initiation): buses 5A and 6A remain energized at event initiation.

- Dominant failure contributors:

  Bus 5A (6A) fails over 6 hours and diesel generators 22 and 23 (21) both fail to start on demand:

  Mean: 3.32×10^{-11}
  Variance: 3.73×10^{-21}

  One transformer fails over 6 hours and all three diesel generators fail to start on demand:

  Mean: 1.58×10^{-11}
  Variance: 8.42×10^{-22}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 1.60×10^{-8}
  Variance: 3.06×10^{-16}

- Diesel generator 22:

  Mean: 1.91×10^{-8}
  Variance: 3.94×10^{-16}

- Diesel generator 23:

  Mean: 1.60×10^{-8}
  Variance: 3.06×10^{-16}

TABLE 1.5.2.2.1-11M (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 5A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

- Diesel generators 21 and 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generators 21 and 23:

  Mean: 5.86×10^{-7}
  Variance: 2.72×10^{-13}

- Diesel generators 22 and 23:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- All three diesel generators:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with diesel generator 21, 22, or 23 inoperable yields:

  Mean: 1.28×10^{-12}
  Variance: 7.58×10^{-24}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

TABLE 1.5.2.2.1-11M (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 5A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with each combination of two diesel generators inoperable yields:

Mean: 4.24×10^{-12}
Variance: 5.67×10^{-23}

- From Section 1.5.2.2.1.4.2, unavailability of three diesel generators due to testing errors:

Mean: $Q_{TE3} = 1.63 \times 10^{-7}$
Variance: 2.02×10^{-13}

Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with all three diesel generators inoperable yields:

Mean: 5.17×10^{-12}
Variance: 1.09×10^{-22}

- Testing contribution to unavailability (Q_T):

Mean: 1.07×10^{-11}
Variance: 1.67×10^{-22}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with diesel generator 21, 22, or 23 inoperable yields:

TABLE 1.5.2.2.1-11M (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 2A, 5A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Maintenance contribution to unavailability (Q_M):

Mean: 1.54×10^{-9}
Variance: 9.13×10^{-19}

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 21, 22, and 23 due to fuel oil supply failure:

  Mean: 3.49×10^{-5}
  Variance: 7.51×10^{-10}

  Applying this to the conditional unavailability of power at buses 2A, 5A, and 6A with all three diesel generators inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 1.11×10^{-9}
  Variance: 1.35×10^{-18}

TABLE 1.5.2.2.1-11N

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A, 5A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.64×10^{-10}
  Variance: 4.35×10^{-19}

- Unavailability on demand (at event initiation): buses 5A and 6A remain energized at event initiation.

- Dominant failure contributors:

  Bus 5A (6A) fails over 6 hours and diesel generators 22 and 23 (21) both fail to start on demand:

  Mean: 3.32×10^{-11}
  Variance: 3.73×10^{-21}

  One transformer fails over 6 hours and all three diesel generators fail to start on demand:

  Mean: 1.58×10^{-11}
  Variance: 8.42×10^{-22}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 1.60×10^{-8}
  Variance: 3.06×10^{-16}

- Diesel generator 22:

  Mean: 1.91×10^{-8}
  Variance: 3.94×10^{-16}

- Diesel generator 23:

  Mean: 1.60×10^{-8}
  Variance: 3.06×10^{-16}

TABLE 1.5.2.2.1-11N (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A, 5A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

- Diesel generators 21 and 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generators 21 and 23:

  Mean: 5.86×10^{-7}
  Variance: 2.72×10^{-13}

- Diesel generators 22 and 23:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- All three diesel generators:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with diesel generator 21, 22, or 23 inoperable yields:

  Mean: 1.28×10^{-12}
  Variance: 7.58×10^{-24}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

TABLE 1.5.2.2.1-11N (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A, 5A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with each combination of two diesel generators inoperable yields:

Mean: 4.24×10^{-12}
Variance: 5.67×10^{-23}

- From Section 1.5.2.2.1.4.2, unavailability of three diesel generators due to testing errors:

Mean: $Q_{ET3} = 1.63 \times 10^{-7}$
Variance: 2.02×10^{-13}

Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with all diesel generators inoperable yields:

Mean: 5.17×10^{-12}
Variance: 1.09×10^{-22}

- Testing contribution to unavailability (Q_T):

Mean: 1.07×10^{-11}
Variance: 1.67×10^{-22}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with diesel generator 21, 22, or 23 inoperable yields:

Maintenance contribution to unavailability (Q_M):

Mean: 1.54×10^{-9}
Variance: 9.13×10^{-19}

TABLE 1.5.2.2.1-11N (continued)

INDIAN POINT 2 FAILURE OF POWER AT BUSES 3A, 5A, AND 6A - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 21, 22, and 23 due to fuel oil supply failure:

  Mean: 3.49×10^{-5}
  Variance: 7.51×10^{-10}

  Applying this to the conditional unavailability of power at buses 3A, 5A, and 6A with all three diesel generators inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 1.11×10^{-9}
  Variance: 1.35×10^{-18}

TABLE 1.5.2.2.1-110

INDIAN POINT 2 FAILURE OF POWER AT ALL 480V BUSES - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Hardware Failure Contribution

- Unavailability over 6 hours (Q_H):

  Mean: 4.63×10^{-10}
  Variance: 4.34×10^{-19}

- Unavailability on demand (at event initiation): buses 5A and 6A remain energized at event initiation.

- Dominant failure contributors:

  Bus 5A (6A) fails over 6 hours and diesel generators 22, and 23 (21) both fail to start on demand:

  Mean: 3.32×10^{-11}
  Variance: 3.73×10^{-21}

  One transformer fails over 6 hours and all three diesel generators fail to start on demand:

  Mean: 1.58×10^{-11}
  Variance: 8.42×10^{-22}

Conditional Unavailability With Diesel Generators Inoperable

- Diesel generator 21:

  Mean: 1.60×10^{-8}
  Variance: 3.05×10^{-16}

- Diesel generator 22:

  Mean: 1.91×10^{-8}
  Variance: 3.94×10^{-16}

- Diesel generator 23: Mean:

  Mean: 1.60×10^{-8}
  Variance: 3.05×10^{-16}

TABLE 1.5.2.2.1-110 (continued)

INDIAN POINT 2 FAILURE OF POWER AT ALL 480V BUSES - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

- Diesel generators 21 and 22:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- Diesel generators 21 and 23:

  Mean: 5.85×10^{-7}
  Variance: 2.71×10^{-13}

- Diesel generators 22 and 23:

  Mean: 7.51×10^{-7}
  Variance: 3.20×10^{-13}

- All three diesel generators:

  Mean: 3.17×10^{-5}
  Variance: 5.14×10^{-10}

Testing Contribution to Unavailability

- From Section 1.5.2.2.1.4.2, unavailability of one diesel generator due to testing errors:

  Mean: $Q_{TE1} = 2.51 \times 10^{-5}$
  Variance: 7.20×10^{-9}

  Applying this to the conditional unavailability of power at all four buses with each of the diesel generators inoperable yields:

  Mean: 1.28×10^{-12}
  Variance: 7.58×10^{-24}

- From Section 1.5.2.2.1.4.2, unavailability of two diesel generators due to testing errors:

  Mean: $Q_{TE2} = 2.03 \times 10^{-6}$
  Variance: 2.34×10^{-11}

TABLE 1.5.2.2.1-110 (continued)

INDIAN POINT 2 FAILURE OF POWER AT ALL 480V BUSES - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Applying this to the conditional unavailability of power at all four buses with each combination of two diesel generators inoperable yields:

Mean: 4.24×10^{-12}
Variance: 5.67×10^{-23}

- From Section 1.5.2.2.1.4.2, unavailability of three diesel generators due to testing errors:

Mean: $Q_{TE3} = 1.63 \times 10^{-7}$
Variance: 2.02×10^{-13}

Applying this to the conditional unavailability of power at all four buses with all three diesel generators inoperable yields:

Mean: 5.17×10^{-12}
Variance: 1.09×10^{-22}

- Testing contribution to unavailability (Q_T):

Mean: 1.07×10^{-11}
Variance: 1.67×10^{-22}

Maintenance Contribution to Unavailability

- From Section 1.5.2.2.1.4.3, unavailability of any diesel generator due to maintenance:

Mean: 3.02×10^{-2}
Variance: 5.44×10^{-5}

Applying this to the conditional unavailability of power at all four buses with each of the diesel generators inoperable yields:

Mean: 1.54×10^{-9}
Variance: 9.13×10^{-19}

TABLE 1.5.2.2.1-110 (continued)

INDIAN POINT 2 FAILURE OF POWER AT ALL 480V BUSES - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery from Failures
Study Period of 6 Hours

Diesel Fuel Oil Supply Contribution to Unavailability

- From Section 1.5.2.2.1.4.4.2, unavailability of diesel generators 21, 22, and 23 due to fuel oil supply failure:

  Mean: 3.49×10^{-5}
  Variance: 7.51×10^{-10}

  Applying this to the conditional unavailability of power at all four buses with all three diesel generators inoperable yields:

  Diesel fuel oil supply failure contribution to unavailability (Q_{FS}):

  Mean: 1.11×10^{-9}
  Variance: 1.35×10^{-18}

TABLE 1.5.2.2.1-12A

INDIAN POINT 2 ELECTRIC POWER SYSTEM NONMUTUALLY EXCLUSIVE FAILURE STATES - OFFISTE POWER NOT AVAILABLE

Boundary Condition: No Recovery From Failures
Study Period of 6 Hours

State	Failure of Power at Bus(es)	Common Cause						Total				
		Hardware Failures	Testing	Maintenance	Fuel Oil Supply	Human Error	Other	Mean	Median	Variance	5th Percentile	95th Percentile
2	2A	1.85-2*	2.51-5	3.02-2	2.43-5	4.50-4	6.96-6	4.86-2	4.82-2	9.01-5	3.36-2	6.10-2
3	3A	1.85-2	2.51-5	3.02-2	2.43-5	4.50-4	6.96-6	4.86-2	4.82-2	9.01-5	3.36-2	6.10-2
4	5A	1.85-2	2.51-5	3.02-2	2.43-5	4.50-4	6.96-6	4.86-2	4.82-2	9.01-5	3.36-2	6.10-2
5	6A	1.85-22	2.51-5	3.02-2	2.43-5	4.50-4	6.96-6	4.86-2	4.82-2	9.01-5	3.36-2	6.10-2
6	2A, 3A	1.85-2	2.51-5	3.02-2	2.43-5	4.50-4	6.96-6	4.85-2	4.81-2	9.01-5	3.36-2	6.09-2
7	2A, 5A	4.09-4	2.96-6	1.12-3	3.01-5	5.32-5	8.48-7	1.62-3	1.53-3	2.24-7	9.33-4	2.31-3
8	2A, 6A	4.09-4	2.96-6	1.12-3	3.01-5	5.32-5	8.48-7	1.62-3	1.53-3	2.24-7	9.33-4	2.31-3
9	3A, 5A	4.09-4	2.96-6	1.12-3	3.01-5	5.32-5	8.48-7	1.62-3	1.53-3	2.24-7	9.33-4	2.31-3
10	3A, 6A	4.09-4	2.96-6	1.12-3	3.01-5	5.32-5	8.48-7	1.62-3	1.53-3	2.24-7	9.33-4	2.31-3
11	5A, 6A	4.09-4	2.96-6	1.12-3	3.01-5	5.32-5	8.48-7	1.62-3	1.53-3	2.24-7	9.33-4	2.31-3
12	2A, 3A, 5A	4.09-4	2.96-6	1.12-3	3.01-5	5.32-5	8.48-7	1.62-3	1.53-3	2.24-7	9.33-4	2.31-3
13	2A, 3A, 6A	4.09-4	2.96-6	1.12-3	3.01-5	5.32-5	8.48-7	1.62-3	1.53-3	2.24-7	9.33-4	2.31-3
14	2A, 5A, 6A	1.04-5	3.06-7	3.70-5	3.49-5	5.53-6	8.77-8	8.82-5	8.31-5	8.56-10	4.59-5	1.36-4
15	3A, 5A, 6A	1.04-5	3.06-7	3.70-5	3.49-5	5.53-6	8.77-8	8.82-5	8.31-5	8.56-10	4.59-5	1.36-4
16	2A, 3A, 5A, 6A	1.04-5	3.06-7	3.70-5	3.49-5	5.53-6	8.77-8	8.82-5	8.31-5	8.56-10	4.59-5	1.36-4

*1.85×10^{-2}

TABLE 1.5.2.2.1-12B

INDIAN POINT 2 ELECTRIC POWER SYSTEM NONMUTUALLY EXCLUSIVE FAILURE STATES - OFFSITE POWER AVAILABLE

Boundary Condition: No Recovery From Failures
Study Period of 6 Hours

State	Failure of Power at Bus(es)	Common Cause						Total				
		Hardware Failures	Testing	Maintenance	Fuel Oil Supply	Human Error	Other	Mean	Median	Variance	5th Percentile	95th Percentile
2	2A	3.88-5*	1.75-9	2.11-6	1.70-9	3.15-8	4.87-10	4.09-5	3.46-5	7.75-10	9.85-6	8.91-5
3	3A	3.88-5	1.75-9	2.11-6	1.70-9	3.15-8	4.87-10	4.09-5	3.46-5	7.75-10	9.85-6	8.91-5
4	5A	7.51-7	7.96-10	9.57-7	7.70-10	1.43-8	2.21-10	1.72-6	1.55-6	5.26-13	7.09-7	2.73-6
5	6A	7.51-7	7.96-10	9.57-7	7.70-10	1.43-8	2.21-10	1.72-6	1.55-6	5.26-13	7.09-7	2.73-6
6	2A, 3A	5.88-7	7.96-10	9.57-7	7.70-10	1.43-8	2.21-10	1.56-6	1.38-6	4.80-13	5.93-7	2.55-6
7	2A, 5A	1.60-8	9.79-11	4.04-8	9.54-10	1.76-9	2.81-11	5.92-8	5.31-8	5.78-16	2.67-8	9.42-8
8	2A, 6A	1.60-8	9.79-11	4.04-8	9.54-10	1.76-9	2.81-11	5.92-8	5.31-8	5.78-16	2.67-8	9.42-8
9	3A, 5A	1.60-8	9.79-11	4.04-8	9.54-10	1.76-9	2.81-11	5.92-8	5.31-8	5.78-16	2.67-8	9.42-8
10	3A, 6A	1.60-8	9.79-11	4.04-8	9.54-10	1.76-9	2.81-11	5.92-8	5.31-8	5.78-16	2.67-8	9.42-8
11	5A, 6A	1.91-8	1.02-10	4.53-8	9.54-10	1.83-9	2.92-11	6.73-8	6.10-8	6.89-16	3.12-8	1.06-7
12	2A, 3A, 5A	1.60-8	9.79-11	4.03-8	9.54-10	1.76-9	2.81-11	5.91-8	5.30-8	5.77-16	2.66-8	9.41-8
13	2A, 3A, 6A	1.60-8	9.79-11	4.03-8	9.54-10	1.76-9	2.81-11	5.91-8	5.30-8	5.77-16	2.66-8	9.41-8
14	2A, 5A, 6A	4.64-10	1.07-11	1.54-9	1.11-9	1.93-10	3.07-12	3.32-9	3.15-9	1.59-18	1.56-9	5.39-9
15	3A, 5A, 6A	4.64-10	1.07-11	1.54-9	1.11-9	1.93-10	3.07-12	3.32-9	3.15-9	1.59-18	1.56-9	5.39-9
16	2A, 3A, 5A, 6A	4.63-10	1.07-11	1.54-9	1.11-9	1.93-10	3.07-12	3.32-9	3.15-9	1.59-18	1.56-9	5.39-9

*3.88×10^{-5}

TABLE 1.5.2.2.1-13A

INDIAN POINT 2 ELECTRIC POWER RECOVERY ACTIONS - OFFSITE POWER NOT AVAILABLE

Failure of Power at Bus(es)	Primary Recovery Action	Estimated Action Time*	Secondary Recovery Action	Estimated Action Time*
2A	Attempt to close breaker EG2A from control room switch	2 minutes	Replace failed breaker EG2A with spare breaker	20 - 30 minutes
3A	Attempt to close breaker EG2B from control room switch	2 minutes	Replace failed breaker EG2B with spare breaker	20 - 30 minutes
5A	Locally start diesel generator 21	20 - 30 minutes	Shed loads and crosstie buses 2A and 5A	20 - 30 minutes
6A	Locally start diesel generator 23	20 - 30 minutes	Shed loads and crosstie buses 3A and 6A	20 - 30 minutes
2A, 3A	Locally start diesel generator 22	20 - 30 minutes	Shed loads and crosstie buses 2A and 5A, 3A and 6A	20 - 30 minutes
2A, 5A	Attempt to close breaker EG2A from control room switch	2 minutes	Locally start diesel generator 21	20 - 30 minutes
2A, 6A	Attempt to close breaker EG2A from control room switch	2 minutes	Locally start diesel generator 23	20 - 30 minutes
3A, 5A	Attempt to close breaker EG2B from control room switch	2 minutes	Locally start diesel generator 21	20 - 30 minutes
3A, 6A	Attempt to close breaker EG2B from control room switch	2 minutes	Locally start diesel generator 23	20 - 30 minutes
5A, 6A	Locally start diesel generators 21 and 23	30 - 40 minutes	Shed loads and crosstie one bus; repair failed diesel generator	20 - 30 minutes 2 - 24 hours
2A, 3A, 5A	Locally start diesel generators 21 and 22	30 - 40 minutes	Crosstie buses 3A and 6A; repair diesel generator 21	20 - 30 minutes 2 - 24 hours
2A, 3A, 6A	Locally start diesel generators 22 and 23	30 - 40 minutes	Crosstie buses 2A and 5A; repair diesel generator 23	20 - 30 minutes 2 - 24 hours
2A, 5A, 6A	Attempt to close breaker EG2A from control room switch	2 minutes	Crosstie buses 3A and 6A; locally start diesel generator 21	20 - 30 minutes 20 - 30 minutes
3A, 5A, 6A	Attempt to close breaker EG2B from control room switch	2 minutes	Crosstie buses 2A and 5A; locally start diesel generator 23	20 - 30 minutes 20 - 30 minutes
All buses	Locally start all diesel generators	50 - 60 minutes	Repair at least one diesel generator	2 - 24 hours

*This is not an estimate of total operator response time which depends upon the precise event scenario. Rather it is an estimate of the time required to effect the given action once that action has been identified as appropriate (i.e., it is approximately equal to total response time minus recognition and evaluation time).

TABLE 1.5.2.2.1-13B

INDIAN POINT 2 ELECTRIC POWER RECOVERY ACTIONS - OFFSITE POWER AVAILABLE

Failure of Power at Bus(es)	Primary Recovery Action	Estimated Action Time*	Secondary Recovery Action	Estimated Action Time*
2A	Attempt to close breaker UT2/ST5 from control room switch	2 minutes	Close breaker EG2A from control room switch	2 minutes
3A	Attempt to close breaker UT3/ST6 from control room switch	2 minutes	Close breaker EG2B from control room switch	2 minutes
5A	Locally start diesel generator 21	20 - 30 minutes	Crosstie buses 3A and 6A	10 - 15 minutes
6A	Locally start diesel generator 23	20 - 30 minutes	Crosstie buses 3A and 6A	10 - 15 minutes
2A, 3A	Locally start diesel generator 22	20 - 30 minutes	Crosstie buses 2A and 5A, buses 3A and 6A	15 - 20 minutes
2A, 5A	Attempt to close breaker EG2A from control room switch	2 minutes	Crosstie buses 2A and 3A; locally start diesel generator 21	10 - 15 minutes 20 - 30 minutes
2A, 6A	Attempt to close breaker EG2A from control room switch	2 minutes	Crosstie buses 2A and 5A, buses 3A and 6A	15 - 20 minutes
3A, 5A	Attempt to close breaker EG2B from control room switch	2 minutes	Crosstie buses 3A and 6A, buses 5A and 2A	15 - 20 minutes
3A, 6A	Attempt to close breaker EG2B from control room switch	2 minutes	Crosstie buses 2A and 3A; locally start diesel generator 23	10 - 15 minutes 20 - 30 minutes
5A, 6A	Crosstie buses 2A and 5A, buses 3A and 6A	15 - 20 minutes	Locally start diesel generators 21 and 23	40 - 50 minutes
2A, 3A, 5A	Reclose normal supply breakers from available sources	10 - 15 minutes	Locally start diesel generators 21 and 22	40 - 50 minutes
2A, 3A, 6A	Reclose normal supply breakers from available sources	10 - 15 minutes	Locally start diesel generators 22 and 23	40 - 50 minutes
2A, 5A, 6A	Reclose normal supply breakers from available sources	10 - 15 minutes	Locally start diesel generators 21 and 23	40 - 50 minutes
3A, 5A, 6A	Reclose normal supply breakers from available sources	10 - 15 minutes	Locally start diesel generators 21 and 23	40 - 50 minutes
All buses	Reclose normal supply breakers from available sources	10 - 15 minutes	Locally start all diesel generators	50 - 60 minutes

*This is not an estimate of total operator response time which depends upon the precise event scenario. Rather it is an estimate of the time required to effect the given action once that action has been identified as appropriate (i.e., it is approximately equal to total response time minus recogniction and evaluation time).

TABLE 1.5.2.2.1-14

INDIAN POINT 2 OFFSITE POWER RECOVERY ACTIONS

Recovery Action	Estimated Action Time*
Energize 6.9 kV buses 5 and 6 from Buchanan 13.8 kV supply (if available)	5 - 10 minutes
Reset transfer trips and sectioning relays to reenergize Buchanan 138 kV or 13.8 kV supply from an available feeder	10 - 20 minutes
Start gas turbine generator unit 1	30 - 60 minutes
Start gas turbine generator units at Buchanan substation	30 - 60 minutes
Repair at least one 138 kV or 13.8 kV feeder to the station	2 - 24 hours
Provide auxilary portable generation equipment to the station	24 - 72 hours

*This is not an estimate of total response time, which depends upon the precise event scenario. Rather, it is an estimate of the time required to effect the given action once that action has been identified as appropriate (i.e., it is approximately equal to total response time minus recognition and evaluation time).

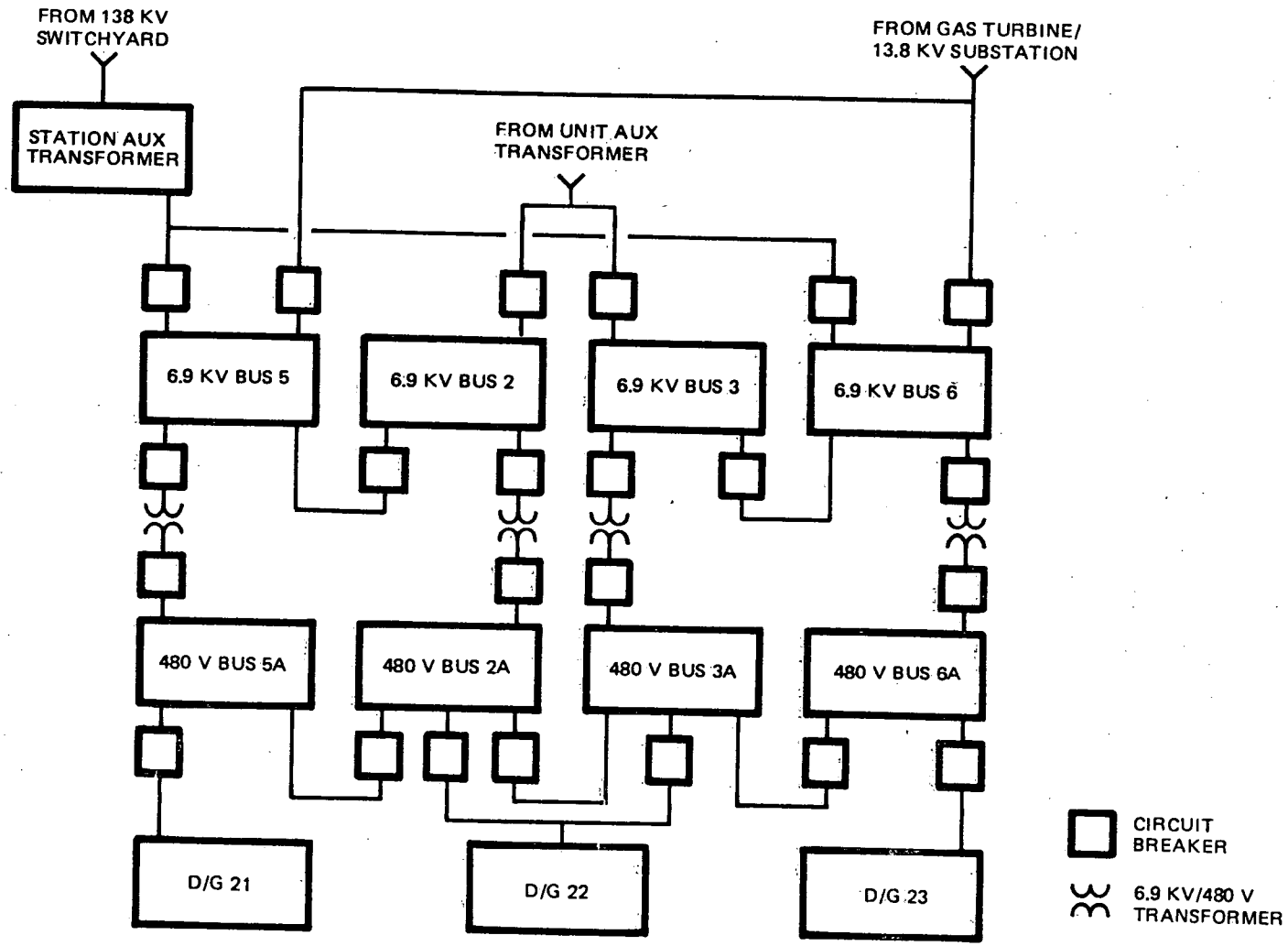


Figure 1.5.2.2.1-1. Indian Point 2 480V Essential Power Supply Block Diagram

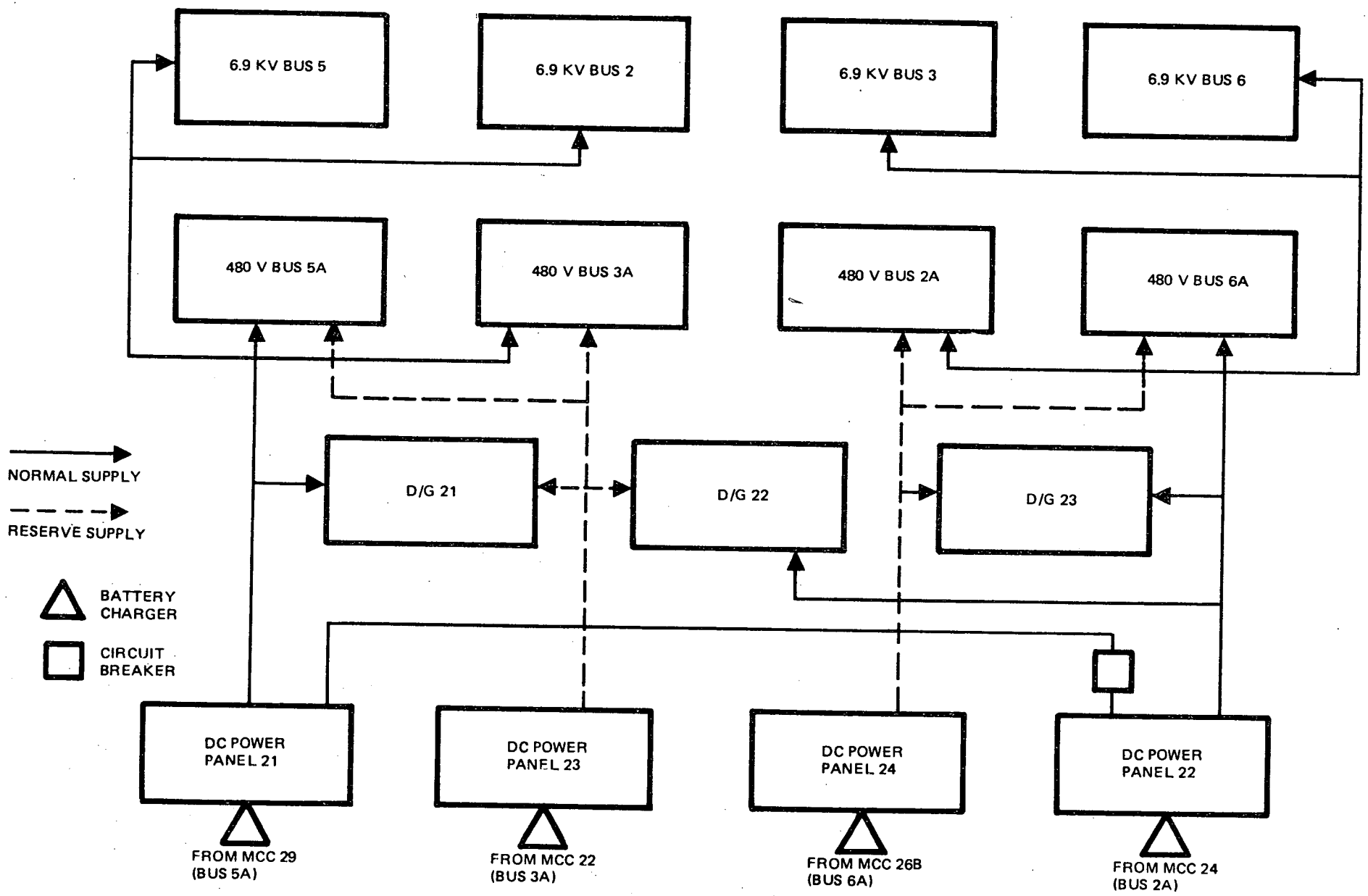


Figure 1.5.2.2.1-2. Indian Point 2 DC Control Power Supply Block Diagram

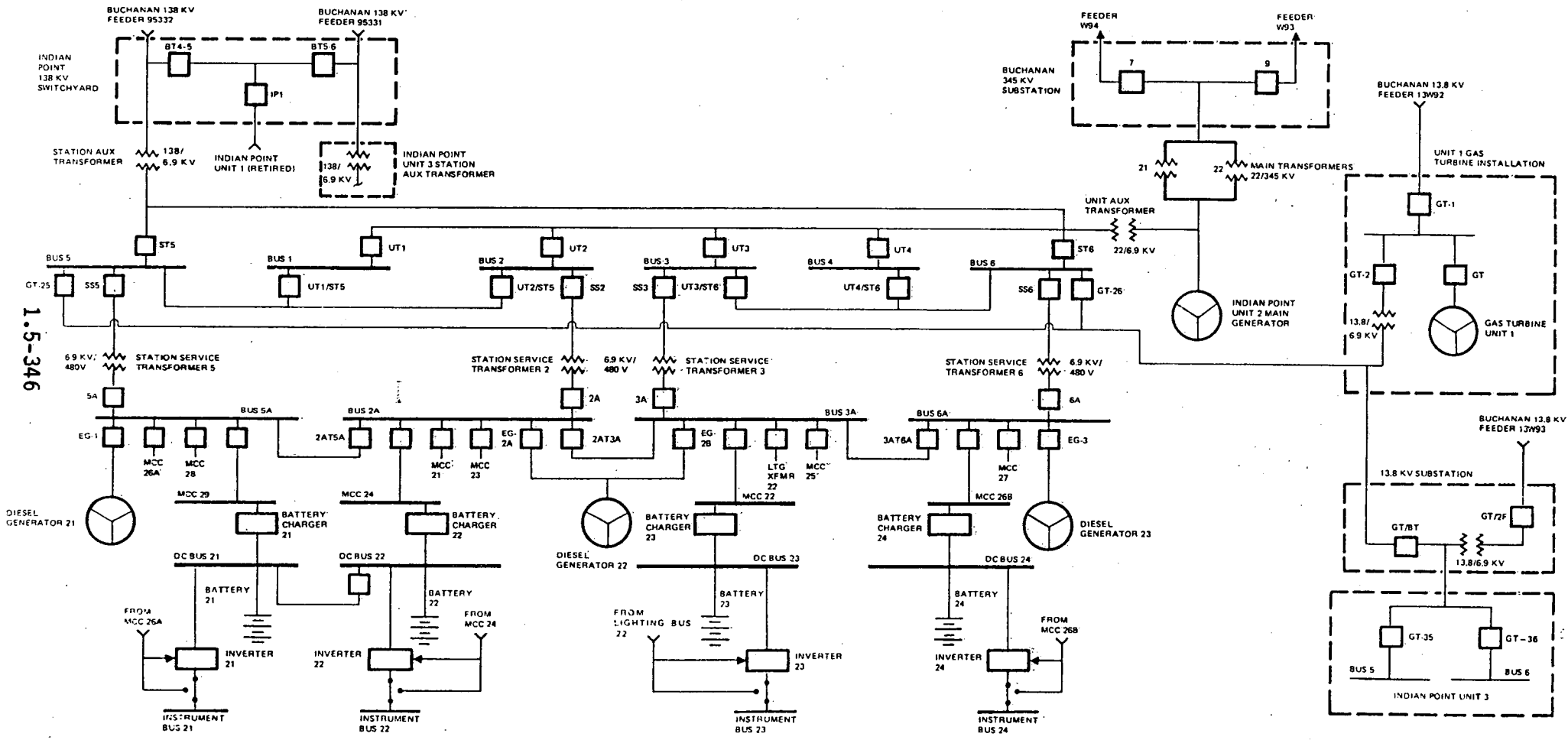


Figure 1.5.2.2.1-3. Indian Point 2 Electric Power System Diagram

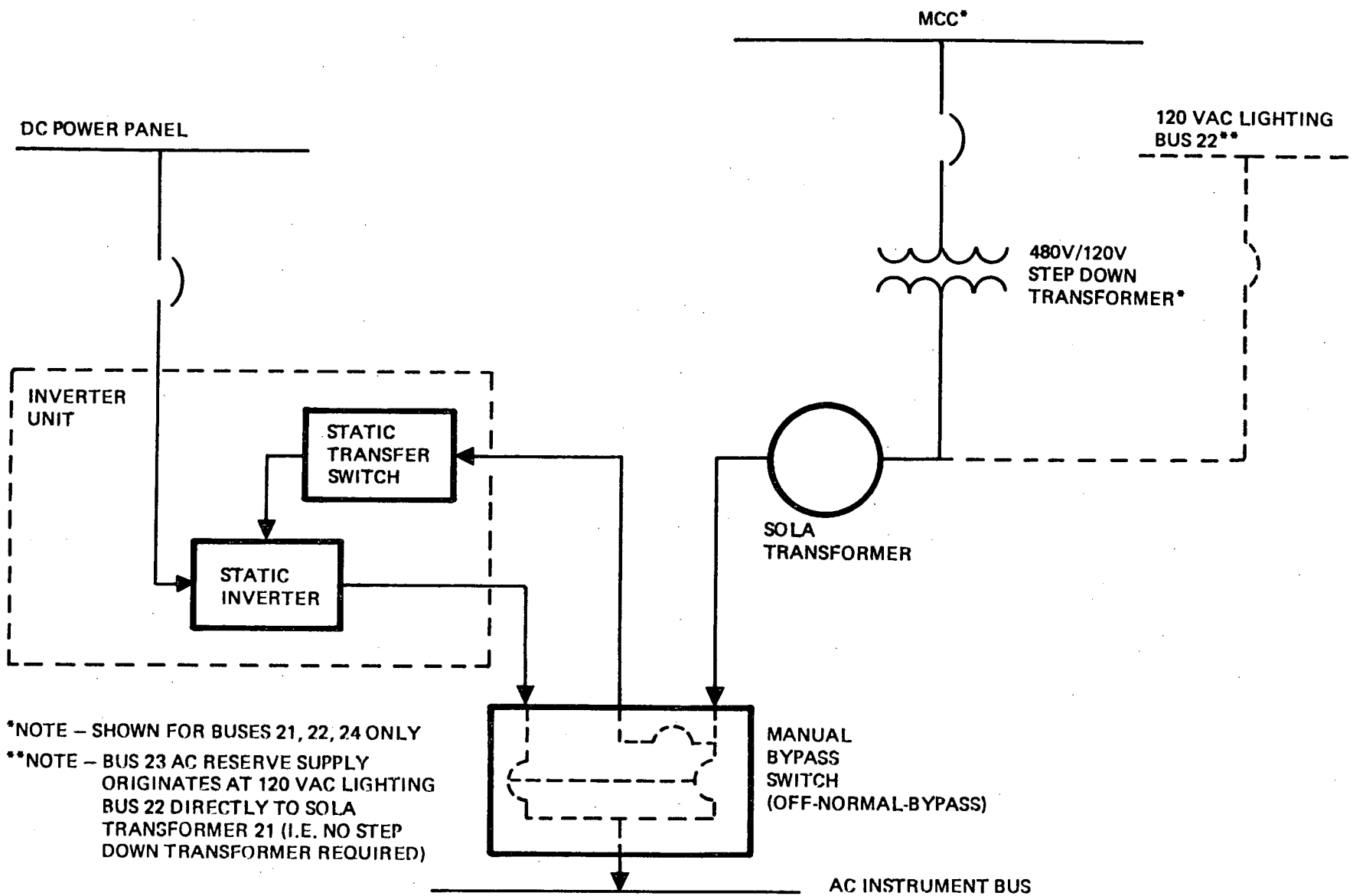
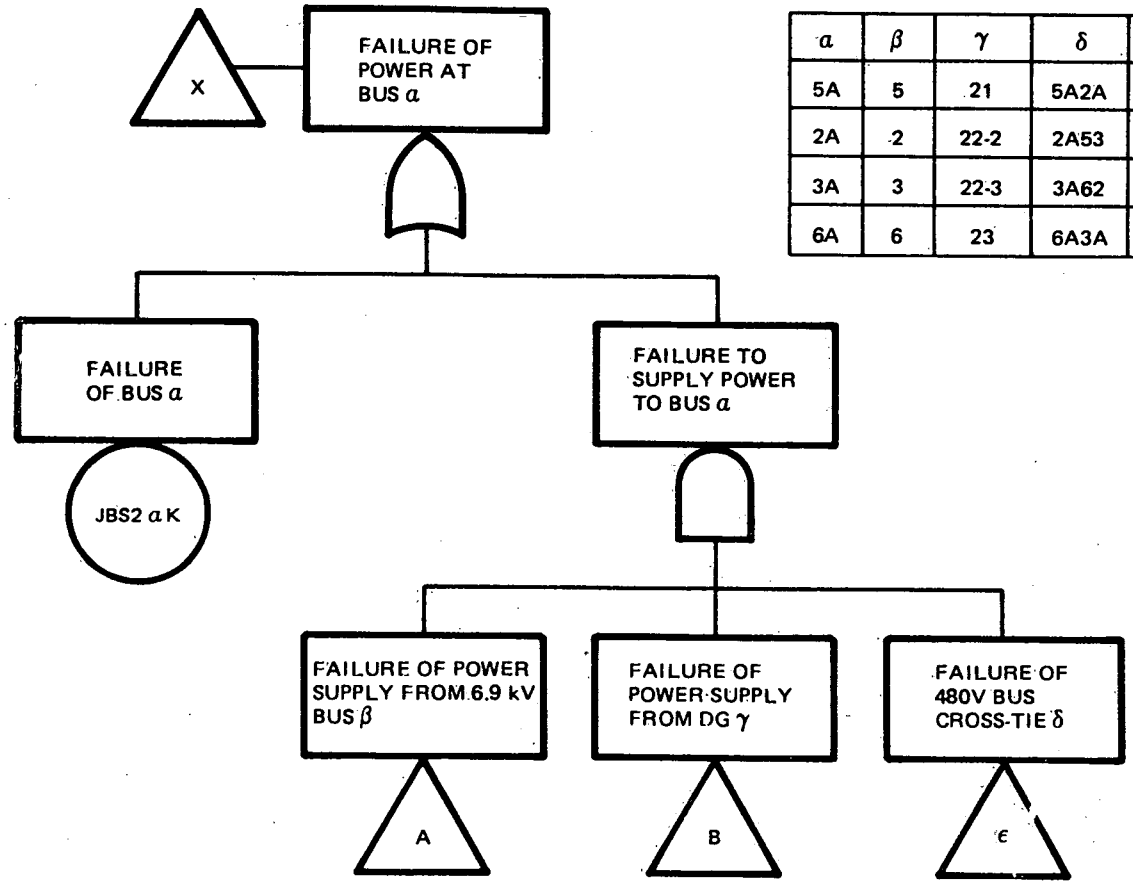
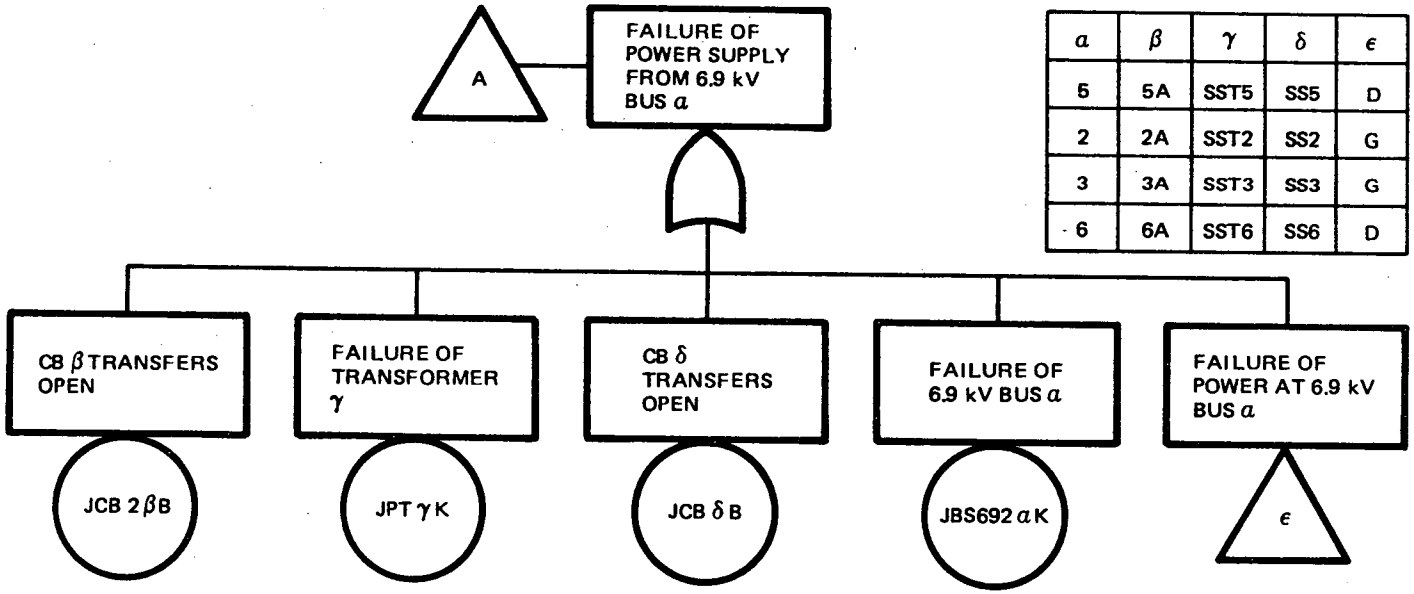


Figure 1.5.2.2.1-4. Indian Point 2 AC Instrument Bus Power Supply



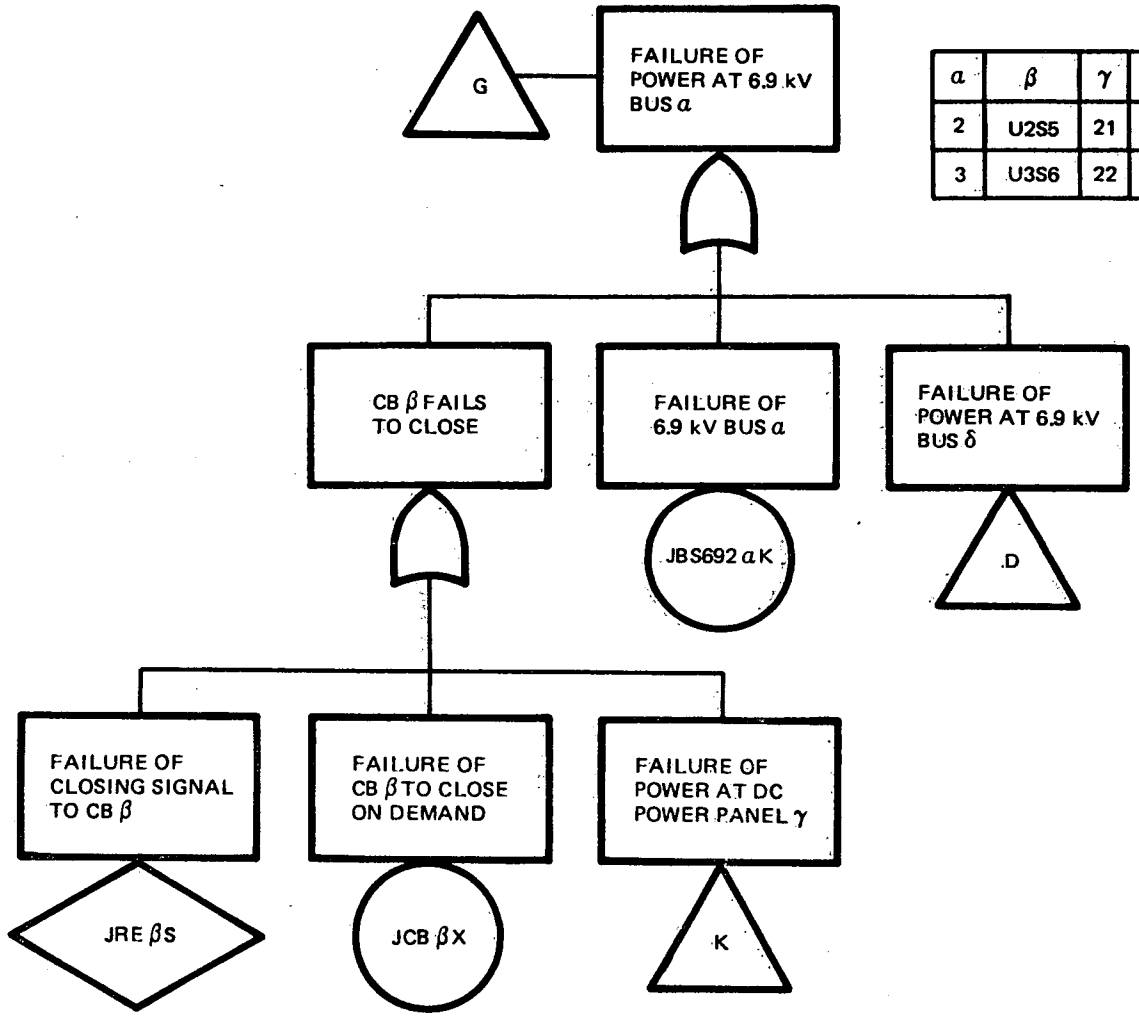
α	β	γ	δ	ε
5A	5	21	5A2A	C
2A	2	22-2	2A53	H
3A	3	22-3	3A62	H
6A	6	23	6A3A	C

Figure 1.5.2.2.1-5. Indian Point 2 Electric Power System Fault Tree (Sheet 1 of 25)



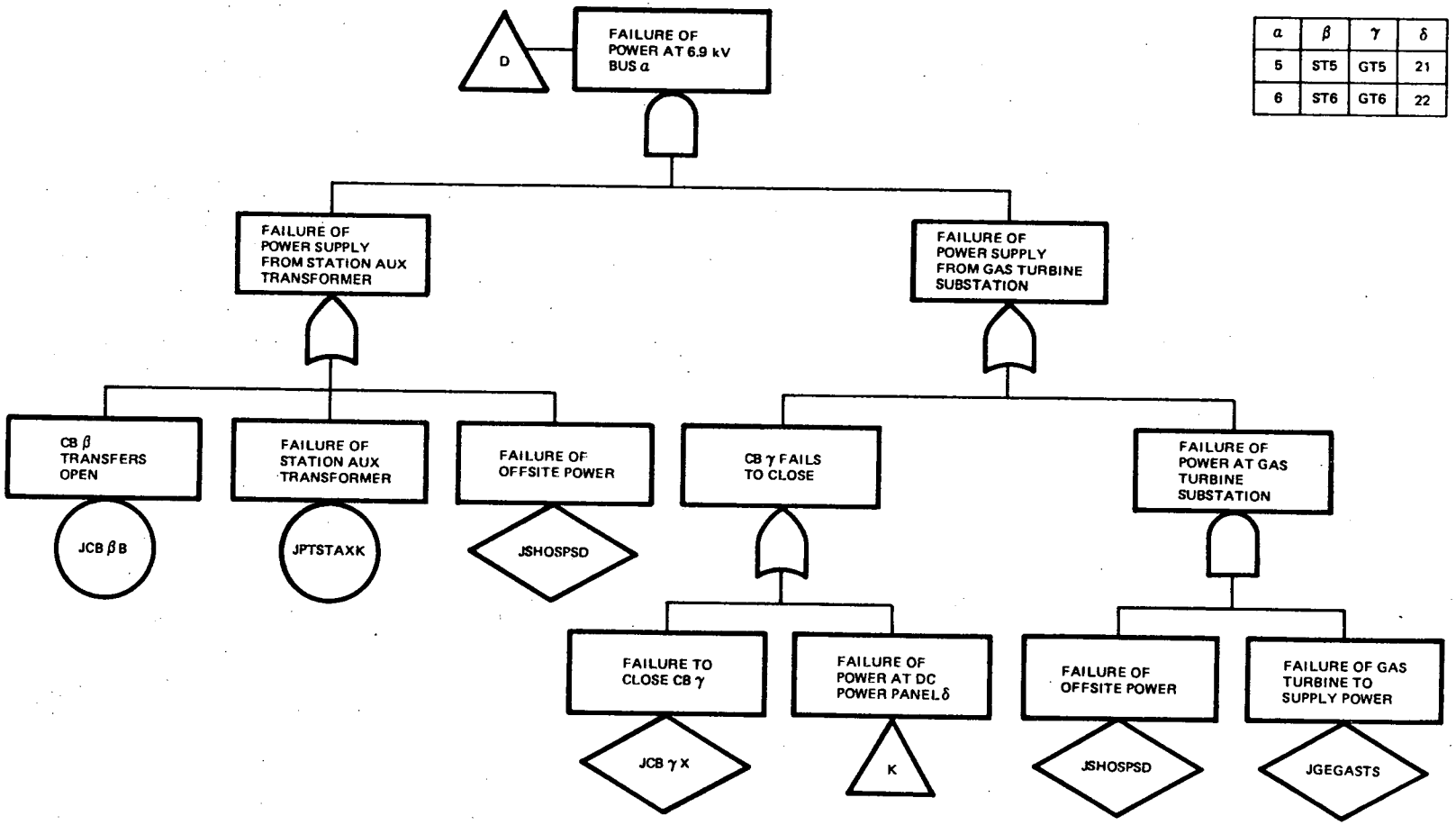
α	β	γ	δ	ε
5	5A	SST5	SS5	D
2	2A	SST2	SS2	G
3	3A	SST3	SS3	G
6	6A	SST6	SS6	D

Figure 1.5.2.2.1-5. (Sheet 2 of 25)



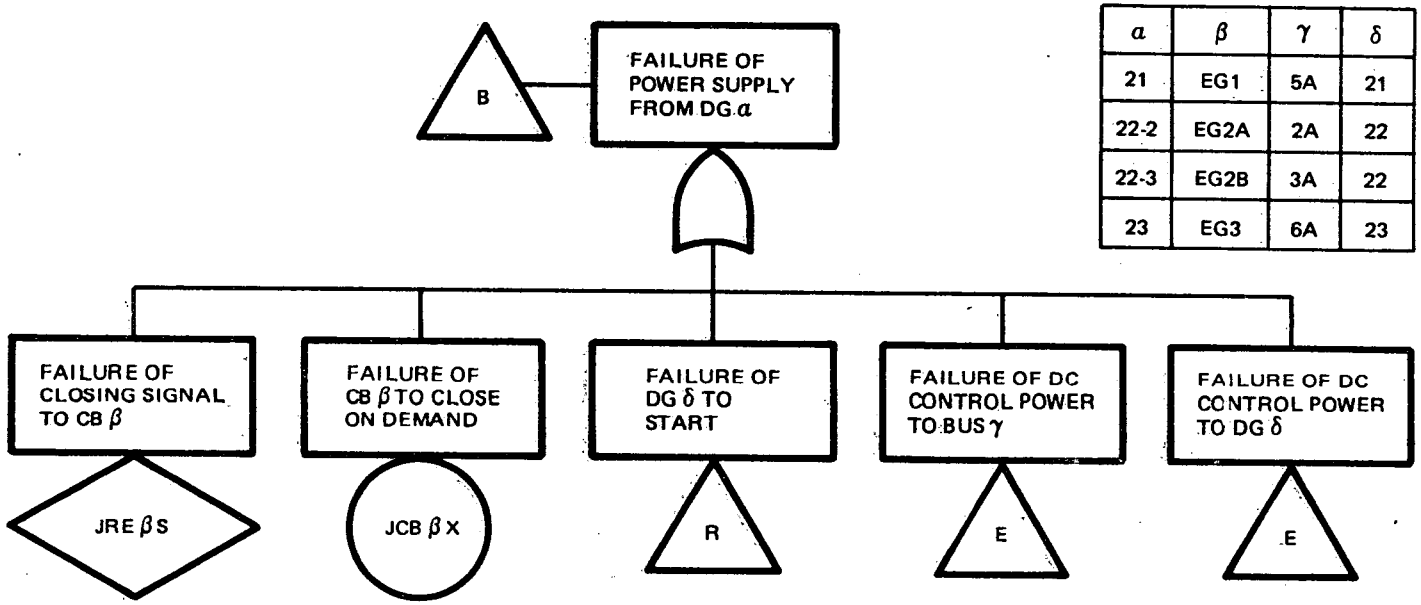
α	β	γ	δ
2	U2S5	21	5
3	U3S6	22	6

Figure 1.5.2.2.1-5. (Sheet 3 of 25)



α	β	γ	δ
5	ST5	GT5	21
6	ST6	GT6	22

Figure 1.5.2.2.1-5. (Sheet 4 of 25)



α	β	γ	δ
21	EG1	5A	21
22-2	EG2A	2A	22
22-3	EG2B	3A	22
23	EG3	6A	23

Figure 1.5.2.2.1-5. (Sheet 5 of 25)

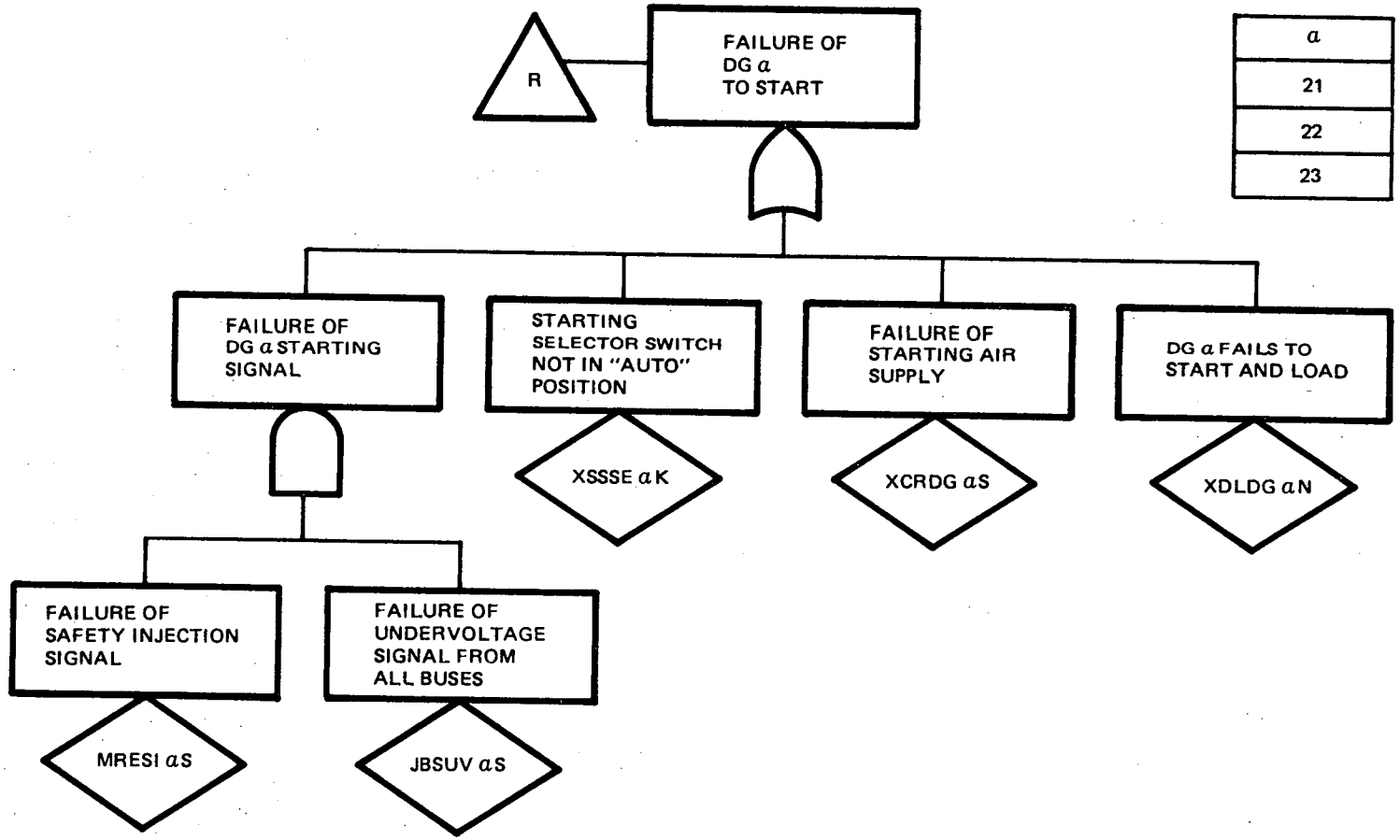
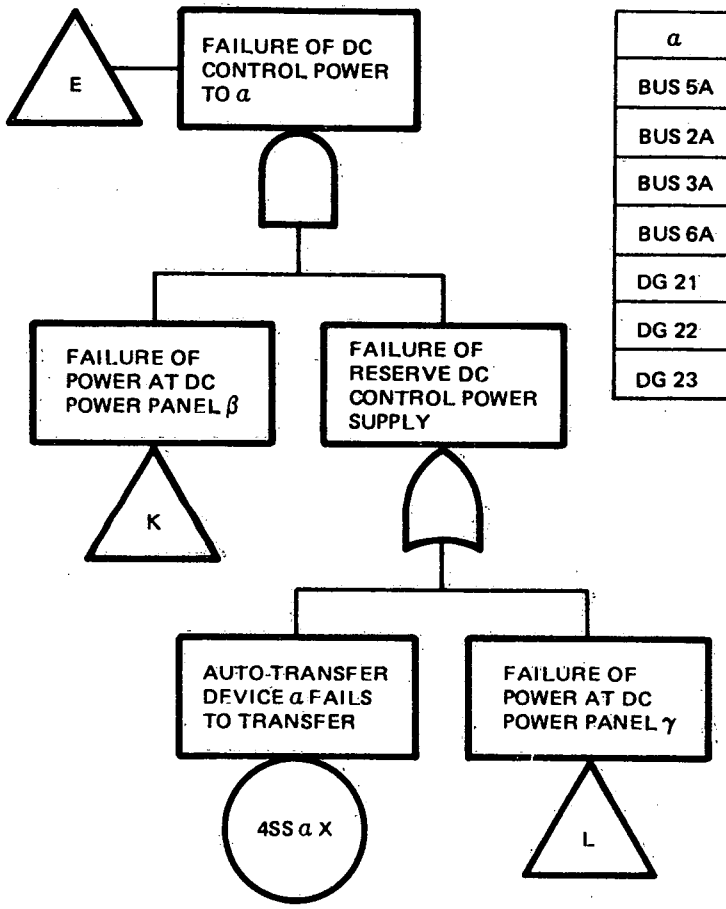
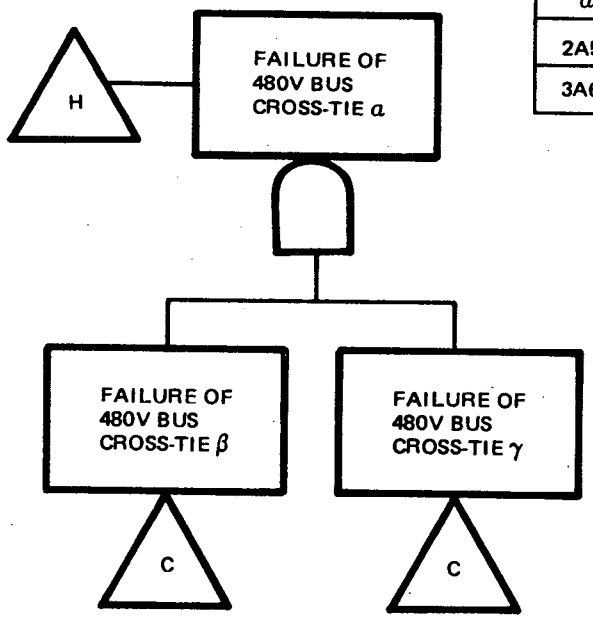


Figure 1.5.2.2.1-5. (Sheet 6 of 25)



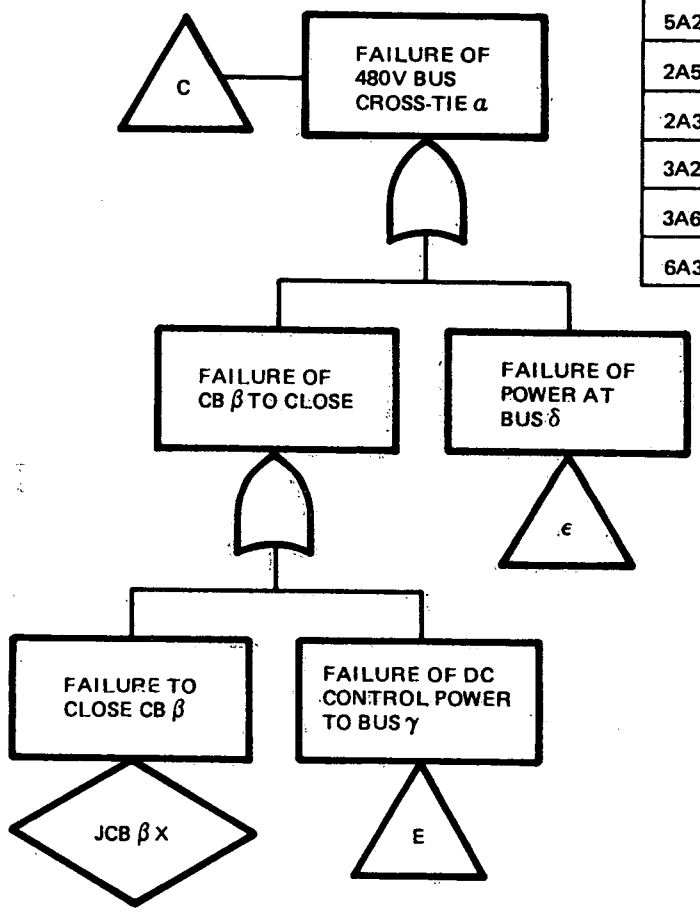
α	β	γ
BUS 5A	21	23
BUS 2A	22	24
BUS 3A	21	23
BUS 6A	22	24
DG 21	21	23
DG 22	22	23
DG 23	22	24

Figure 1.5.2.2.1-5. (Sheet 7 of 25)



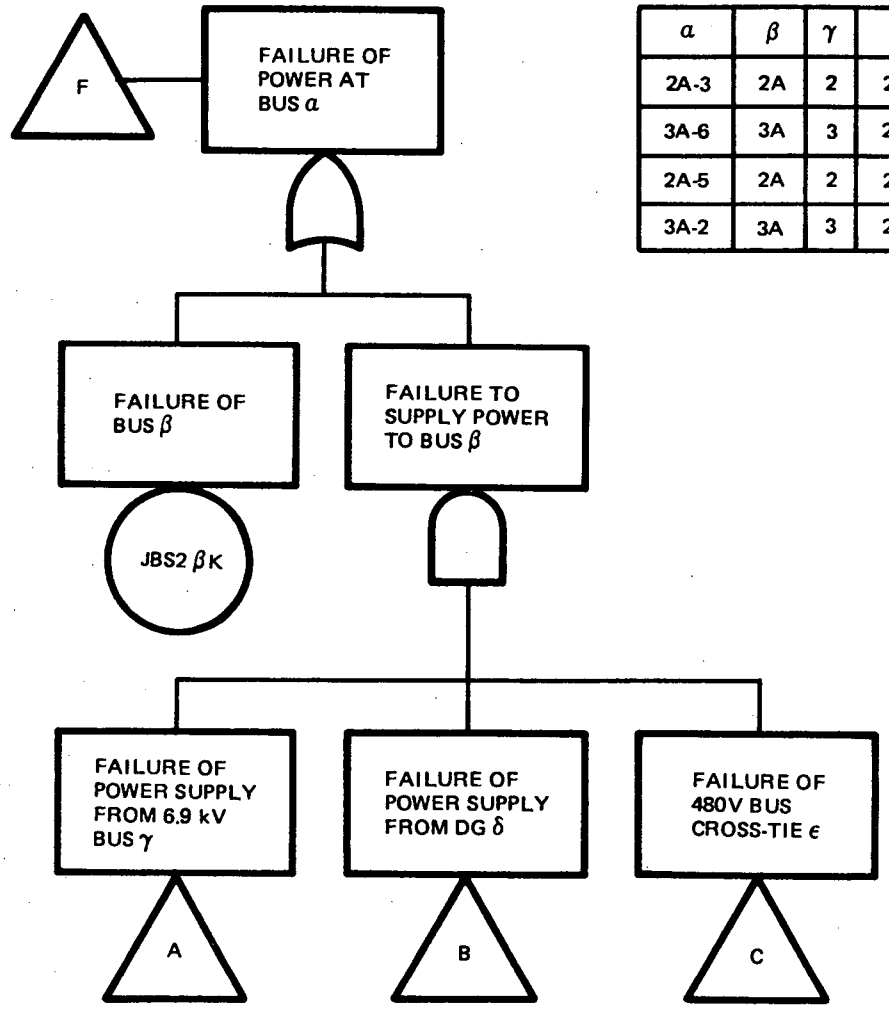
α	β	γ
2A53	2A5A	2A3A
3A62	3A6A	3A2A

Figure 1.5.2.2.1-5. (Sheet 8 of 25)



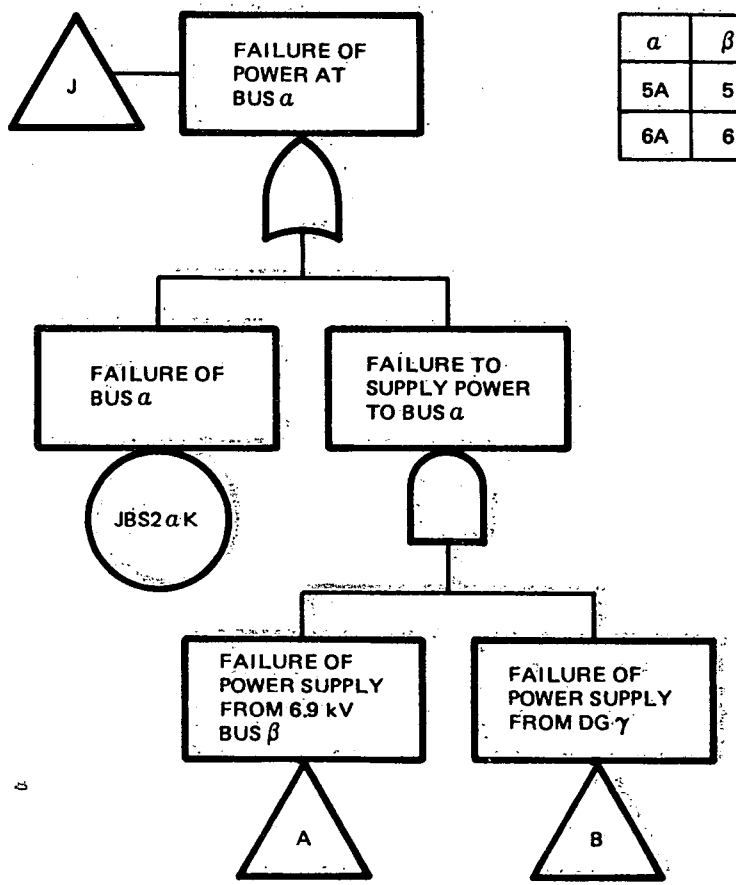
α	β	γ	δ	ε
5A2A	2A5A	2A	2A-3	F
2A5A	2A5A	2A	5A	J
2A3A	2A3A	2A	3A-6	F
3A2A	2A3A	2A	2A-5	F
3A6A	3A6A	6A	6A	J
6A3A	3A6A	6A	3A-2	F

Figure 1.5.2.2.1-5. (Sheet 9 of 25)



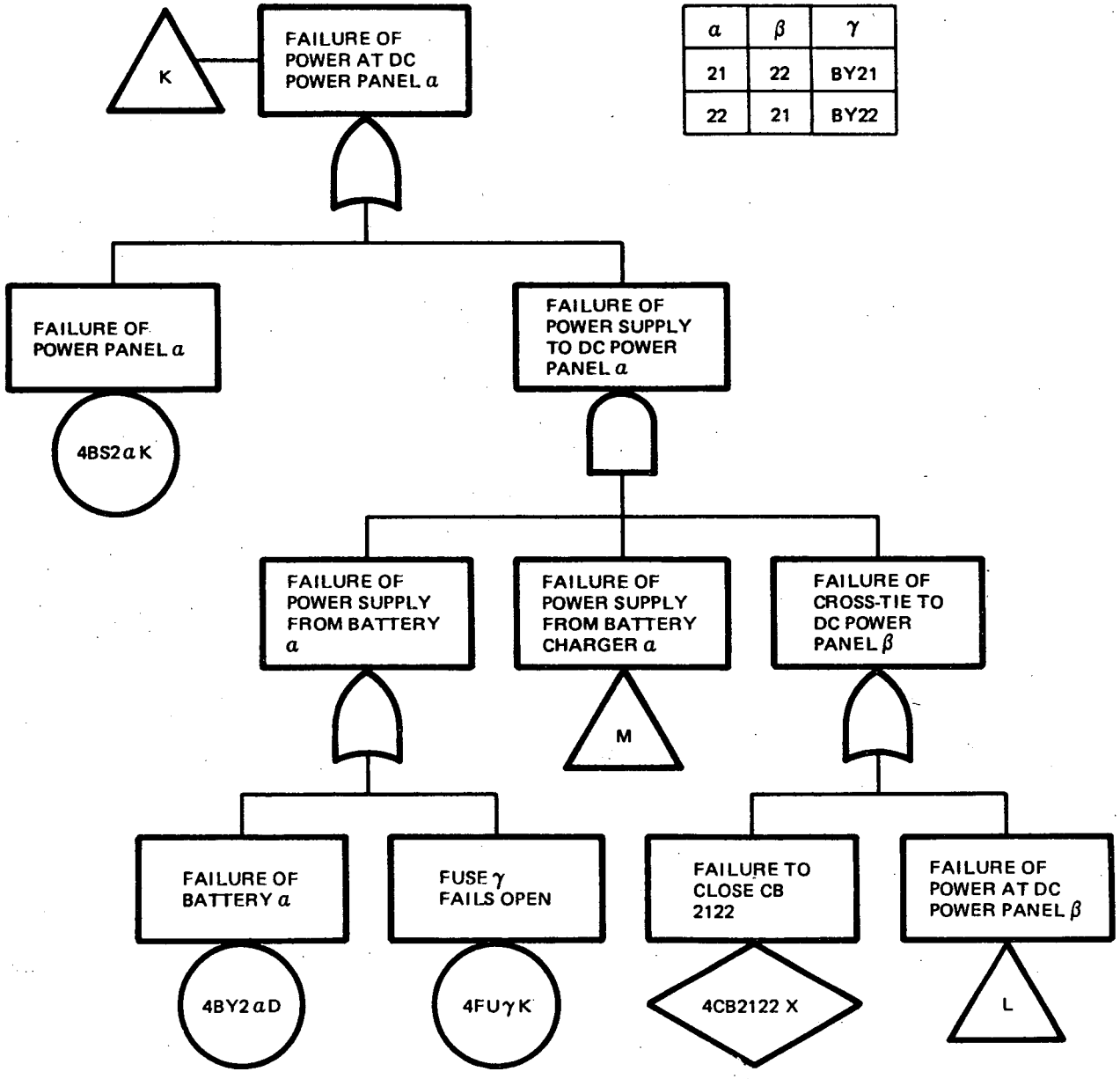
α	β	γ	δ	ε
2A-3	2A	2	22-2	2A3A
3A-6	3A	3	22-3	3A6A
2A-5	2A	2	22-2	2A5A
3A-2	3A	3	22-3	3A2A

Figure 1.5.2.2.1-5. (Sheet 10 of 25)



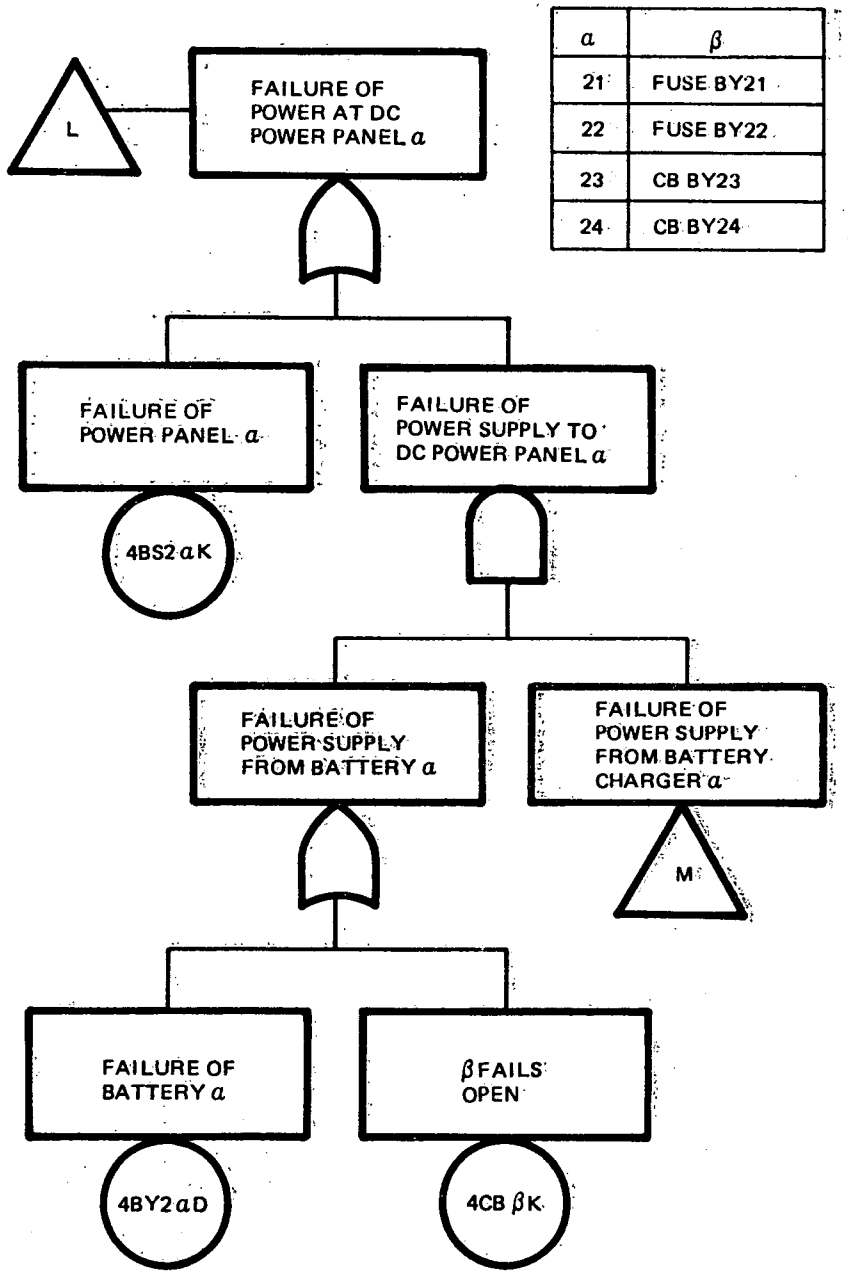
α	β	γ
5A	5	21
6A	6	22

Figure 1.5.2.2.1-5. (Sheet 11 of 25)



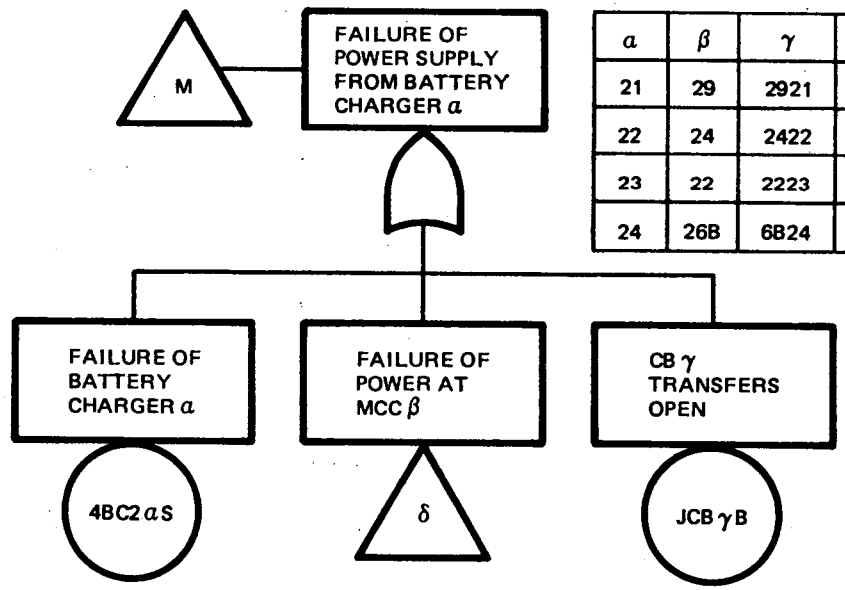
α	β	γ
21	22	BY21
22	21	BY22

Figure 1.5.2.2.1-5. (Sheet 12 of 25)



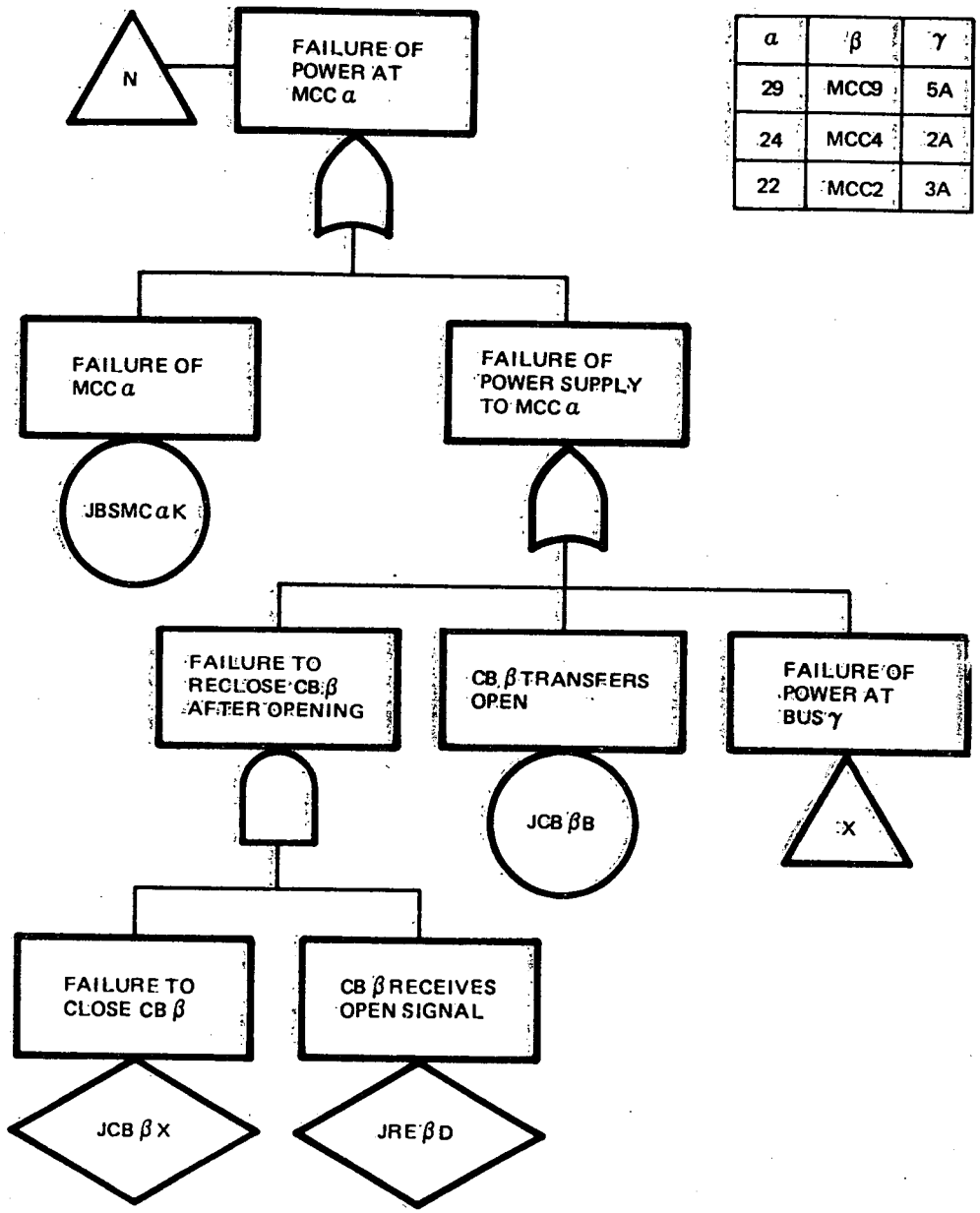
α	β
21	FUSE BY21
22	FUSE BY22
23	CB BY23
24	CB BY24

Figure 1.5.2.2.1-5. (Sheet 13 of 25)



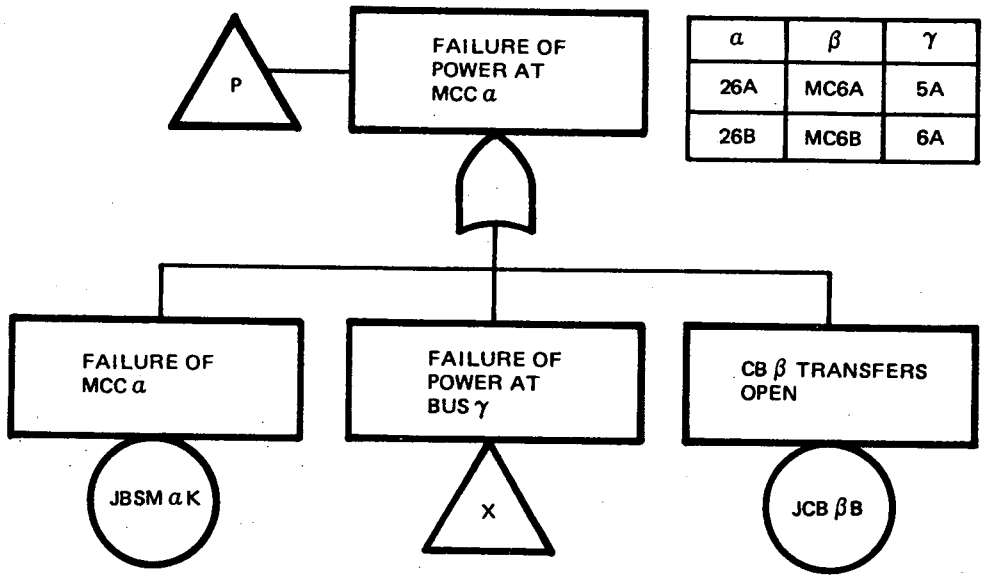
α	β	γ	δ
21	29	2921	N
22	24	2422	N
23	22	2223	N
24	26B	6B24	P

Figure 1.5.2.2.1-5.[illegible] (Sheet 14 of 25)



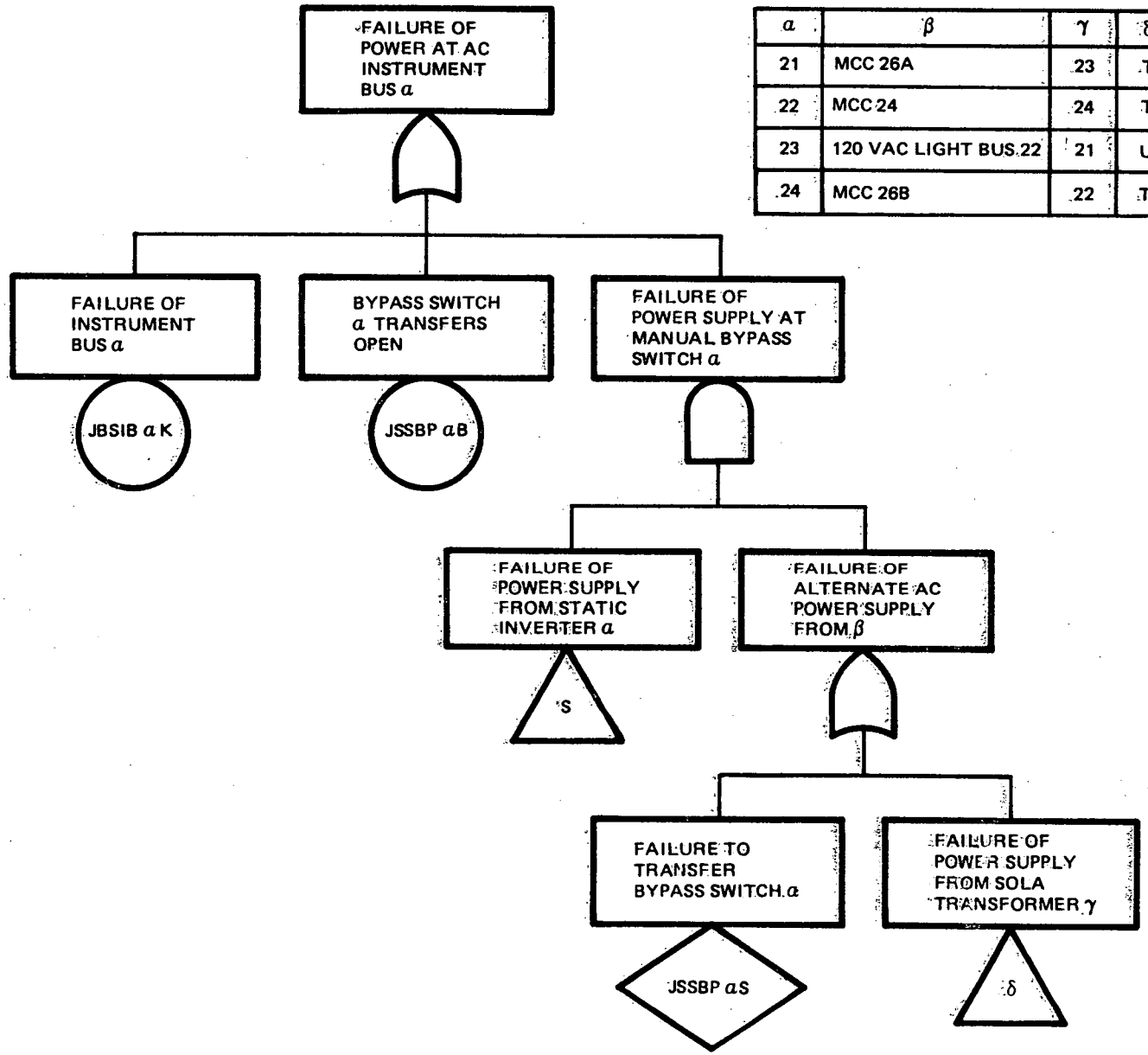
α	β	γ
29	MCC9	5A
24	MCC4	2A
22	MCC2	3A

Figure 1.5.2.2.1-5. (Sheet 15 of 25)



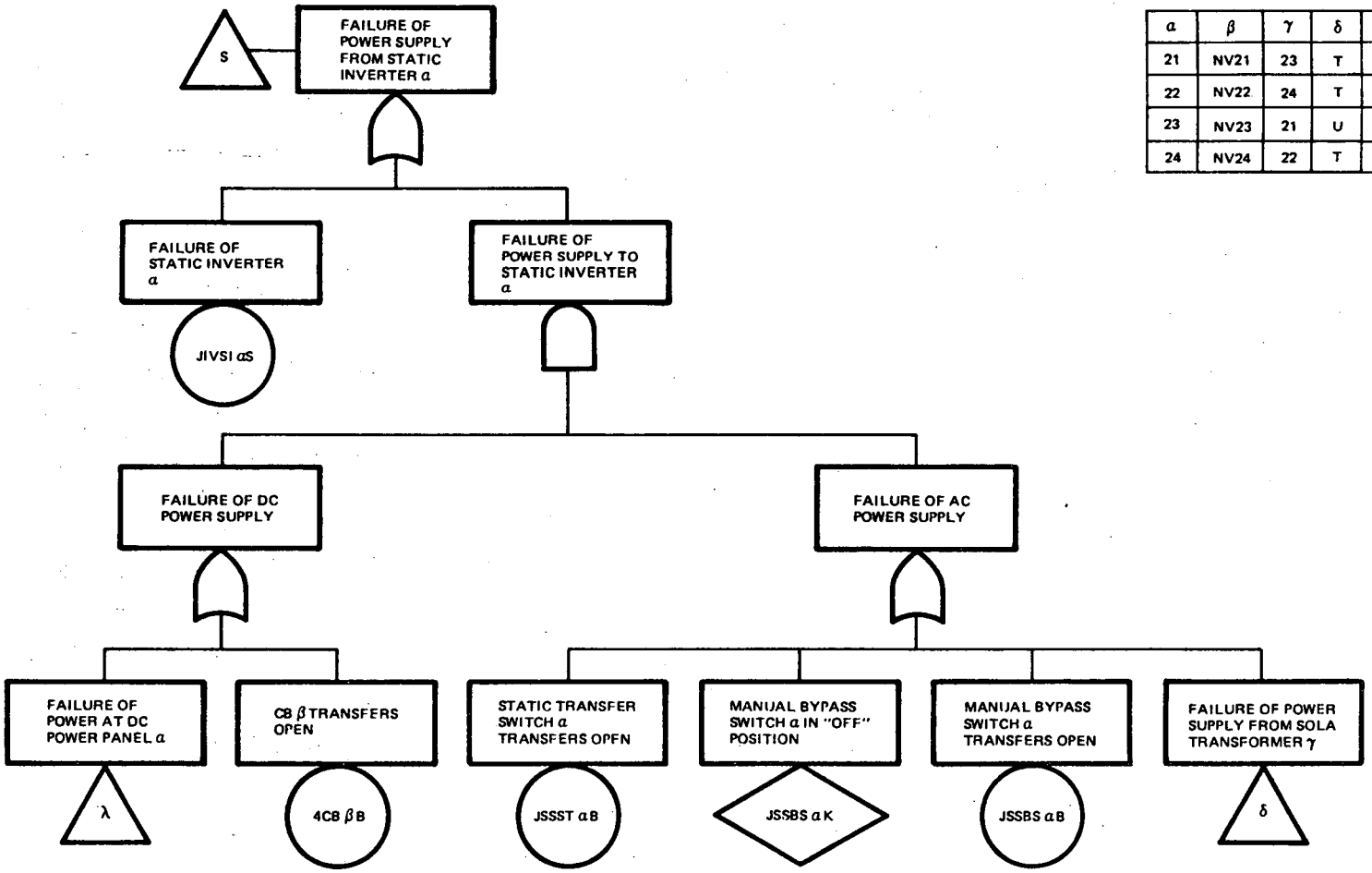
α	β	γ
26A	MC6A	5A
26B	MC6B	6A

Figure 1.5.2.2.1-5. (Sheet 16 of 25)



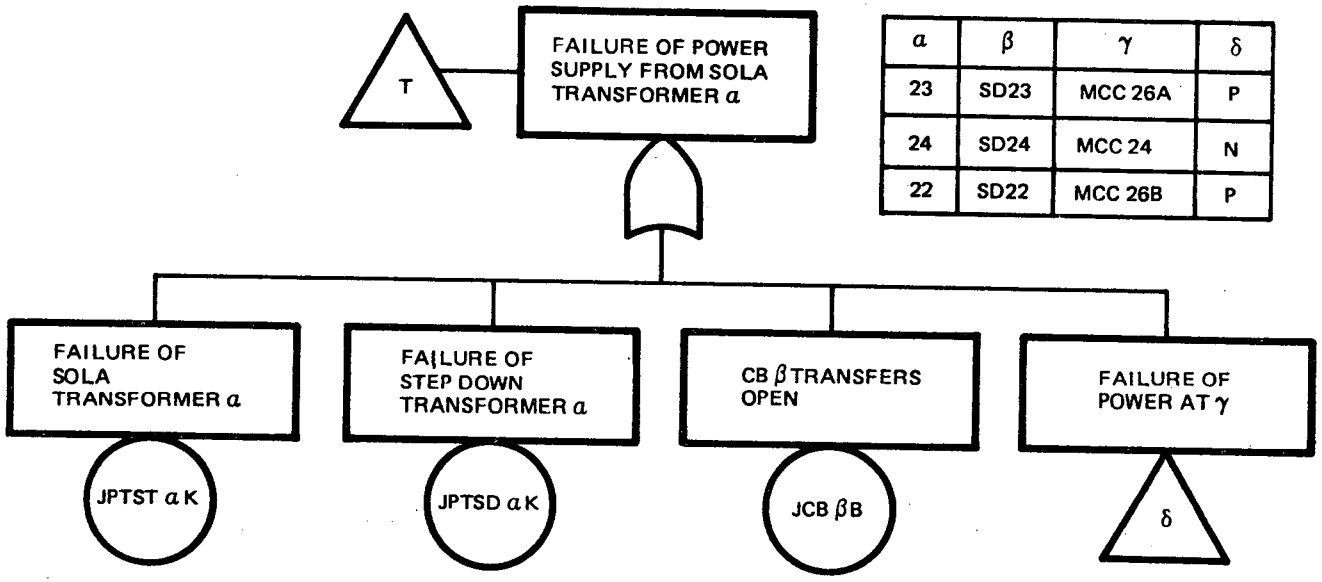
α	β	γ	δ
21	MCC 26A	23	T
22	MCC 24	24	T
23	120 VAC LIGHT BUS 22	21	U
24	MCC 26B	22	T

Figure 1.5.2.2.1-5. (Sheet 17 of 25)



α	β	γ	δ	λ
21	NV21	23	T	K
22	NV22	24	T	K
23	NV23	21	U	L
24	NV24	22	T	L

Figure 1.5.2.2.1-5. (Sheet 18 of 25)



α	β	γ	δ
23	SD23	MCC 26A	P
24	SD24	MCC 24	N
22	SD22	MCC 26B	P

Figure 1.5.2.2.1-5. (Sheet 19 of 25)

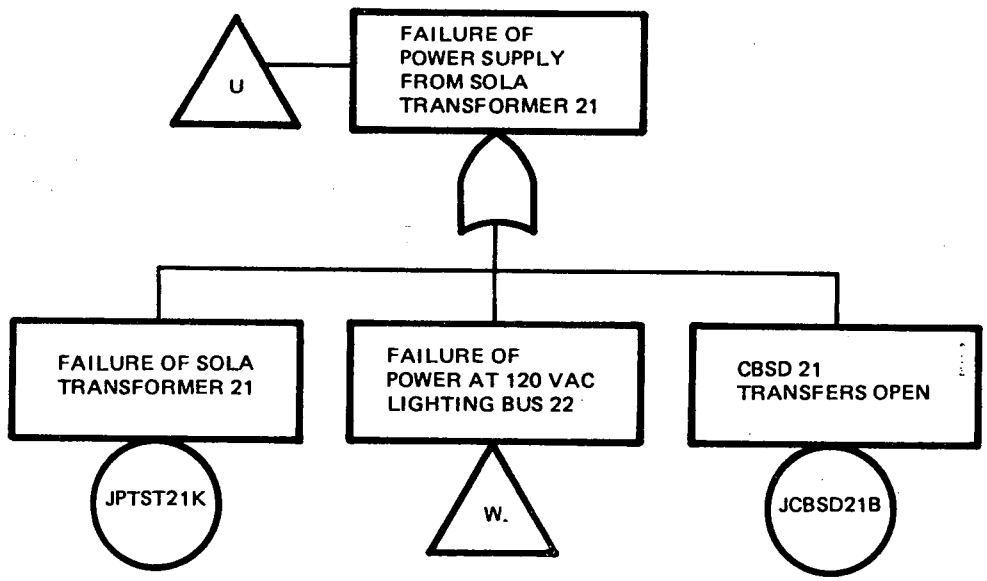
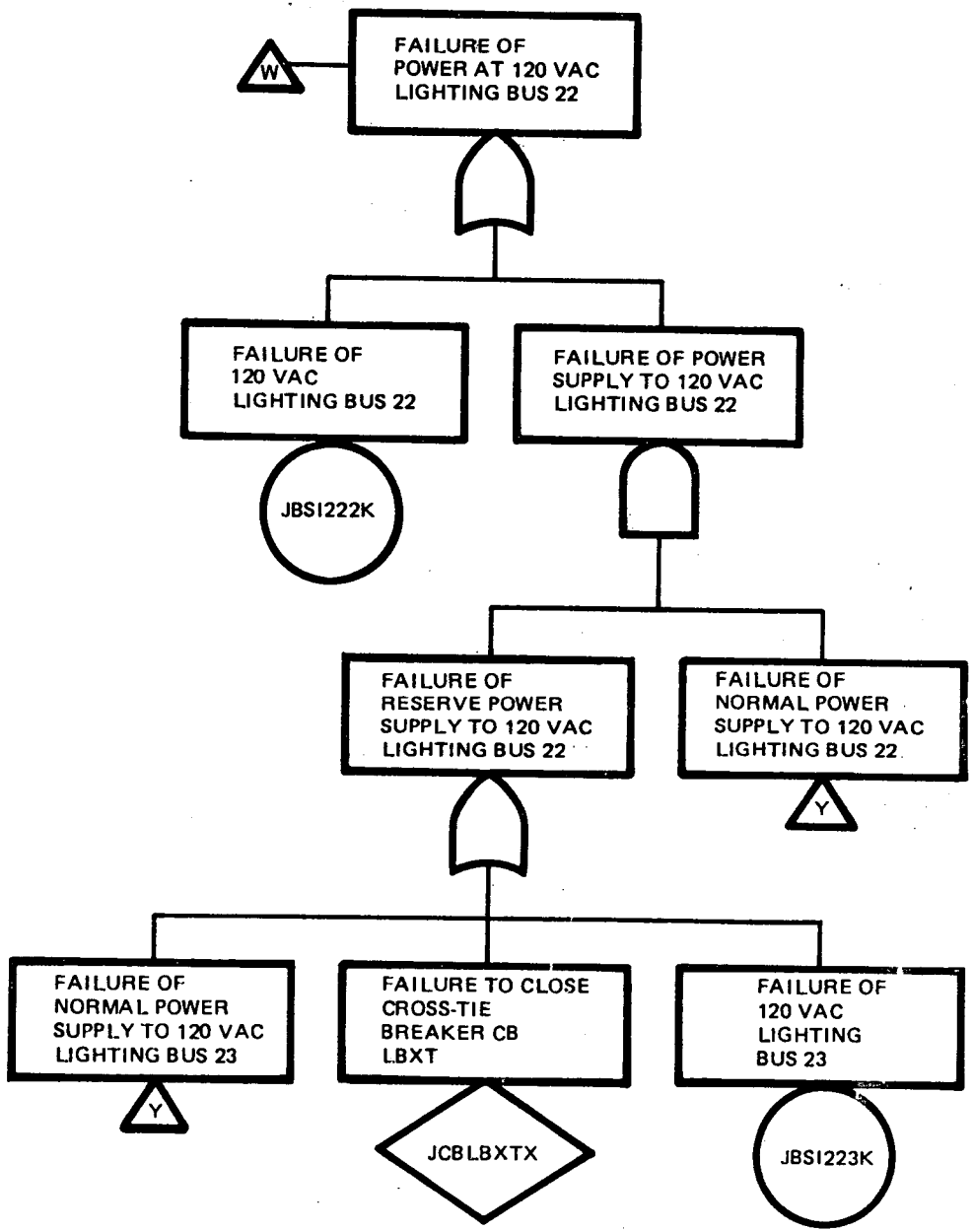


Figure 1.5.2.2.1-5. (Sheet 20 of 25)



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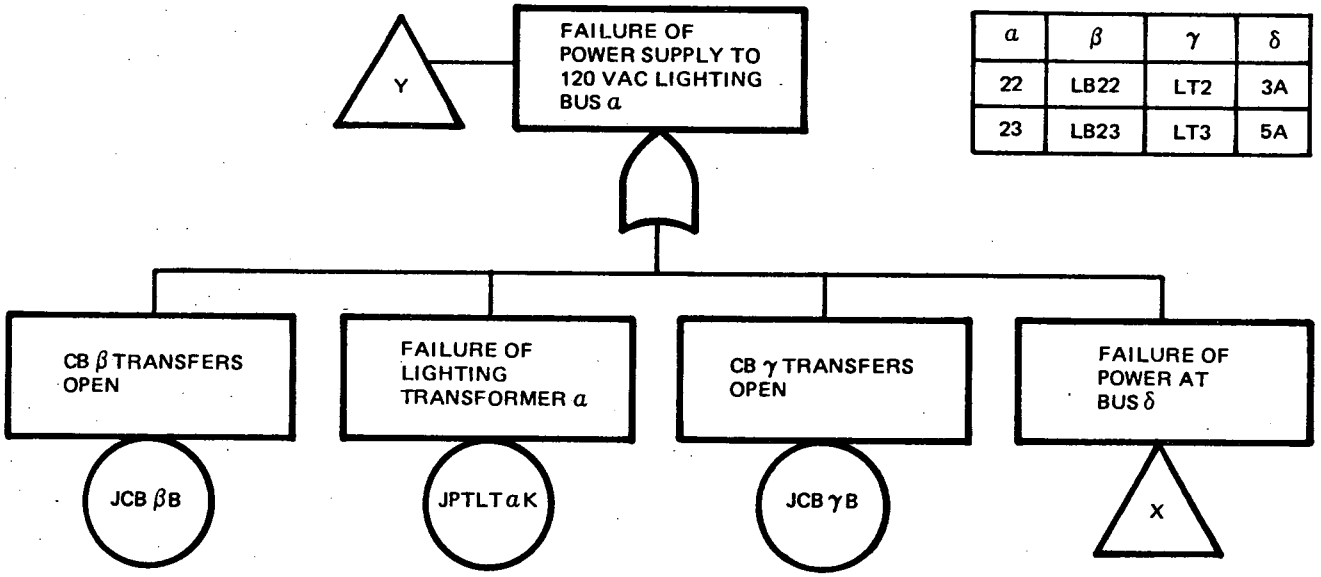

α	β	γ	δ
22	LB22	LT2	3A
23	LB23	LT3	5A

Figure 1.5.2.2.1-5. (Sheet 22 of 25)

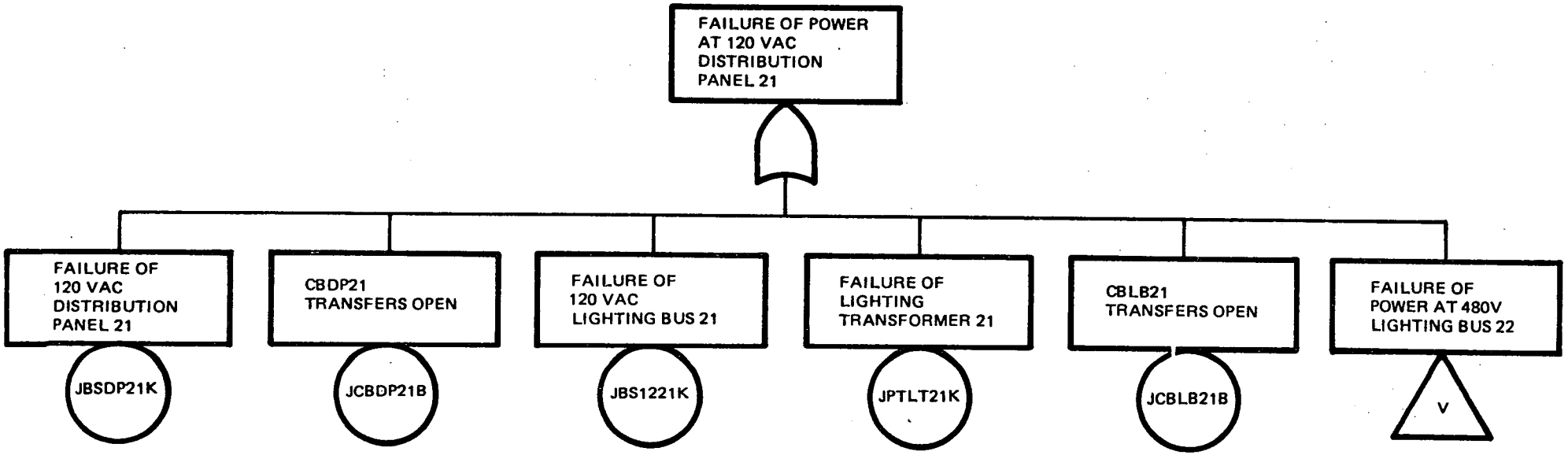

Figure 1.5.2.2.1-5. (Sheet 23 of 25)

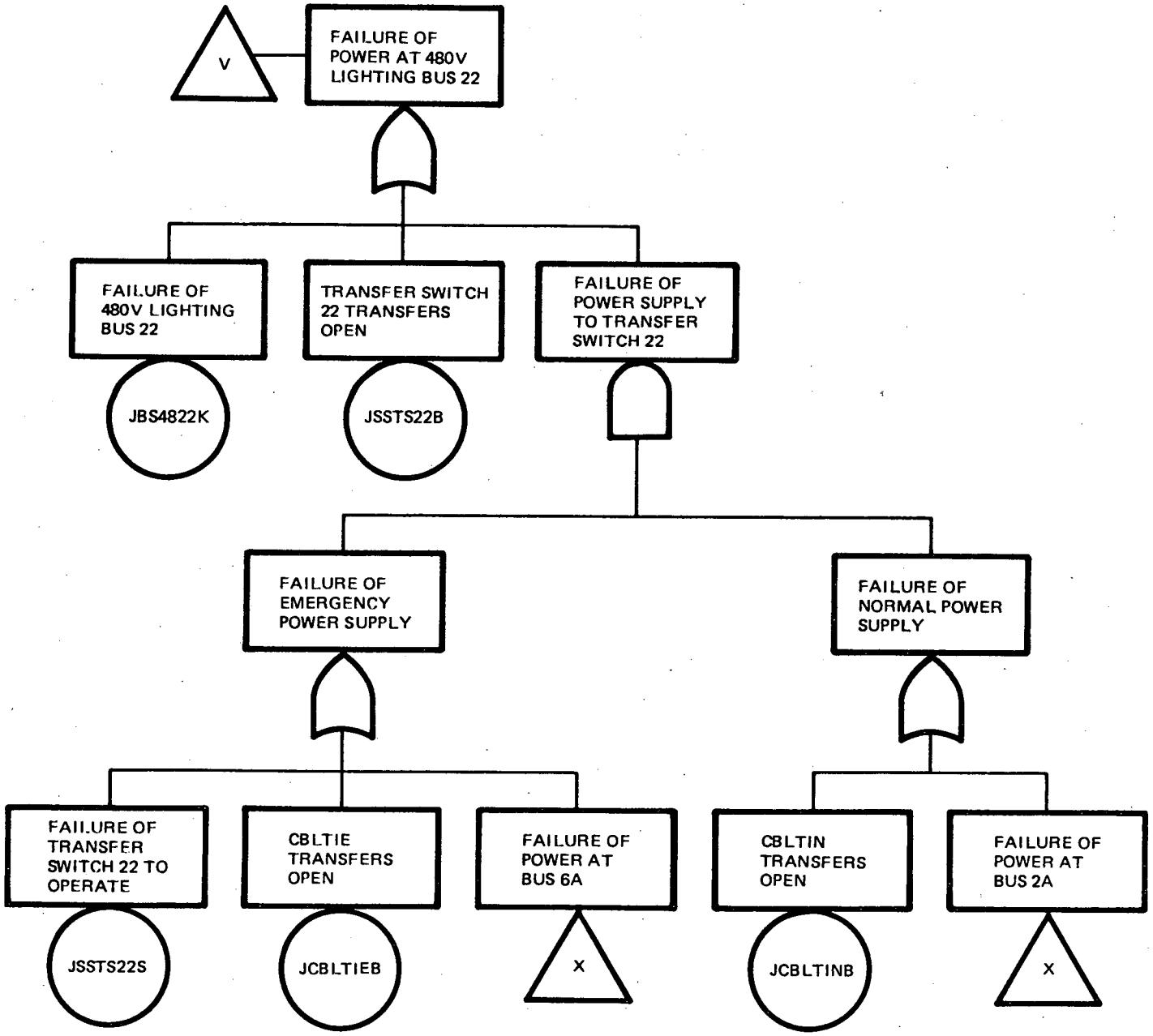

Figure 1.5.2.2.1-5. (Sheet 24 of 25)

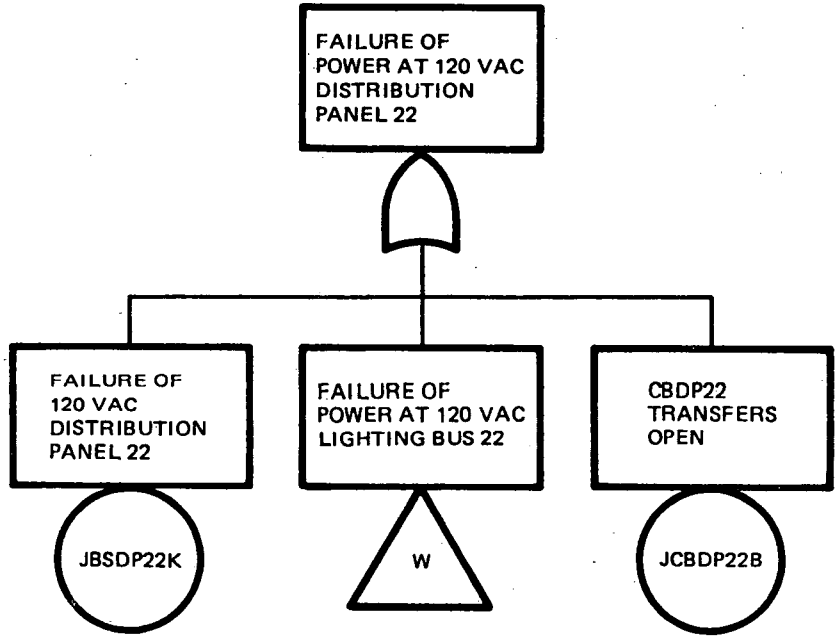

Figure 1.5.2.2.1-5. (Sheet 25 of 25)

1.5.2.2.2 Indian Point 2 Reactor Protection System

1.5.2.2.2.1 Summary.

1.5.2.2.2.1.1 Introduction. The reactor protection system (RPS) is evaluated in the context of a small loss of coolant accident (LOCA) or plant transients. The RPS protects the core from overpower conditions resulting from infrequent transients.

The analysis is carried out under the following conditions:

- The conditions in the plant require a reactor scram.
- No operator action is taken to scram the plant.

1.5.2.2.2.1.2 Results. Table 1.5.2.2.2-1, "Reactor Protection System Failure to Scram," presents the results of the analysis of the RPS for Indian Point 2. The analysis has shown the following dominant contributors to RPS failure:

Reactor Protection System Failure	Mean
• Random coincident failures of two trains of the trip system.	9.6×10^{-6} (48%)
• Failures while in test or maintenance.	6.2×10^{-6} (31%)
• Failure of the rod control cluster assemblies to enter the core.	3.8×10^{-6} (19%)

A comparison of the results of this analysis and the RPS analysis of the Reactor Safety Study (RSS) is presented below.

Frequency of Failure to Scram	Indian Point 2	RSS
5th Percentile	4.3×10^{-7}	1.3×10^{-5}
Median	4.2×10^{-6}	3.6×10^{-5}
95th Percentile	7.0×10^{-5}	1.0×10^{-4}

1.5.2.2.2.1.3 Conclusions. The failure of the RPS system is dominated by random failures in the logic channels, predominantly wiring faults. Operator action to manually scram the plant is successful because the manual scram switch bypasses all logic channel failures.

Failure of the rod control cluster assemblies (RCCAs) to insert is not immediately correctable with operator action; however, the frequency of this event is 3.8×10^{-6} per demand, which is equivalent to one failure to scram in every 250,000 demands.

The frequency distribution of RPS failure on demand is shown in Figure 1.5.2.2.2-1.

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1.5.2.2.2.2 System Description.

1.5.2.2.2.2.1 System Function. The reactor protection system and the engineered safety features (ESF) make up the protective systems of Indian Point 2.

The RPS performs the following primary functions:

1. Protects the reactor core against fuel rod cladding damage caused by departure from nucleate boiling or high power density.

2. Protects against reactor coolant system damage caused by high primary system pressure.

3. Protects the reactor coolant system from sudden loss of its heat sink through the steam generators.

4. In conjunction with ESF systems, detects a failure of the reactor coolant system and initiates actions to mitigate the consequences of the accident.

A simplified block diagram of the RPS is presented in Figure 1.5.2.2.2-2. Figure 1.5.2.2.2-3 presents a simplified system arrangement diagram. Figure 1.5.2.2.2-4 presents a typical reactor trip breaker schematic diagram.

1.5.2.2.2.2.2 System Operation. The RPS utilizes trip signals from various process sensors to deenergize undervoltage devices in two series-connected reactor trip breakers. The reactor trip breakers open and remove power from the control rod drive mechanism magnetic coils. When power is removed from the magnetic coils, the rod control cluster assemblies fall into the active fuel region of the reactor core, thereby inserting negative reactivity and making the reactor subcritical.

The parameters measured by the process instrumentation and their associated scram setpoints are presented in Table 1.5.2.2.2-2. The required scram logic for the process sensors is also included in Table 1.5.2.2.2-2; for example, two out of four means that at least two channels out of four available channels must indicate that a scram condition exists before a scram signal is generated.

The process instrumentation is separated into a number of channels (maximum of four channels) with each channel receiving power from a different 120 VAC instrument bus. Upon loss of power, an instrumentation channel is designed to fail in the mode that generates a scram signal.

The signal generated in the instrumentation loop is sent to the trip bistable for that loop. As the setpoint is reached, the bistable changes state from on to off which deenergizes the associated scram logic relays in the reactor protection logic racks. In addition to the instrument loop bistable, the loops also provide indication, alarm, and interlock functions.

There are two channels of actuation logic. Each reactor trip bistable drives two relays, one in each actuation logic channel. The logic channels are duplicates of each other and are physically separated.

The logic channels are energized from separate 125 VDC buses. Loss of power from a 125 VDC bus deenergizes the undervoltage trip device in the reactor trip breaker causing the reactor trip breaker to open.

The scram logic relay contacts are arranged in a matrix to develop the required logic configuration for each reactor trip signal. The output of a logic matrix is fed to two parallel reactor trip relays. The parallel arrangement prevents a scram from a failed open trip relay. There are eight parallel reactor trip relay sets. These sets are arranged as shown in Figure 1.5.2.2.2-3. The logic matrices supplying each set of reactor trip relays is presented in Table 1.5.2.2.2-3.

Each logic channel energizes the undervoltage trip device in two reactor trip breakers. The two reactor trip breakers and the two bypass trip breakers are in a series-parallel arrangement, as shown in Figure 1.5.2.2.2-2. During normal operation, reactor trip breakers RTA and RTB are closed and power from the rod drive motor generator sets must pass through both trip breakers. During testing, a trip bypass breaker, either BYA or BYB, is closed to allow testing of the associated reactor trip breaker. In this condition, a single logic channel supplies both the normal reactor trip breaker and the trip bypass breaker. This arrangement allows one logic channel to be tested to the reactor trip breaker. The trip bypass breakers are electrically interlocked to prevent more than one bypass breaker from being closed at a time. If one bypass breaker is closed, the other bypass breaker will be electrically prevented from closing.

The reactor trip breakers are operated by 125 VDC from separate DC sources. To close a reactor trip or trip bypass breaker, DC power must be available and the undervoltage coil must be energized.

Manual reactor trip is provided by two trip switches in the control room. These switches deenergize the trip breaker undervoltage coils through the logic system and energize separate trip coils which are part of the breaker control circuit. An individual trip switch for each breaker at the breaker panels mechanically trips the reactor trip or reactor trip bypass breakers.

Power from the rod drive motor generator set is supplied through the reactor trip breakers to the rod control panels. The rod control panels convert the power from AC to DC and distribute it to the individual control rod drive mechanisms. During normal operation the control rods are fully withdrawn from the reactor core and the stationary gripper coils are energized from the rod control panels. Upon a loss of power, all coil assemblies are deenergized, the stationary gripper latches disengage from the control rod drive shaft, and the control rod drive shaft and rod control cluster assemblies drop into the active core region thus shutting down the reactor.

1.5.2.2.2.2.3 Technical Specifications. The plant technical specifications identify:

- The maximum or minimum trip setpoints.
- The frequency of testing of the various RPS components.
- The number of out of service instrumentation or logic channels.
- Limits on the number of channel tests that may be performed at the same time.

1.5.2.2.2.2.4 Support Systems. The RPS is independent of any supporting systems.

1.5.2.2.2.2.5 Interfacing Systems. The RPS interfaces with the 120 VAC instrument power supply system and the 125 VDC battery power system.

The four instrument buses supply power to the reactor protective system instrument channels as shown in Table 1.5.2.2.2-4. This table also shows the battery system supplies to the RPS logic channels and the reactor trip and bypass breakers.

1.5.2.2.2.2.6 Testing and Maintenance. The various components in the reactor protection system undergo periodic testing and surveillance. Maintenance is performed as required.

1. The process instrumentation channels are periodically tested to satisfy plant technical specifications as indicated below:

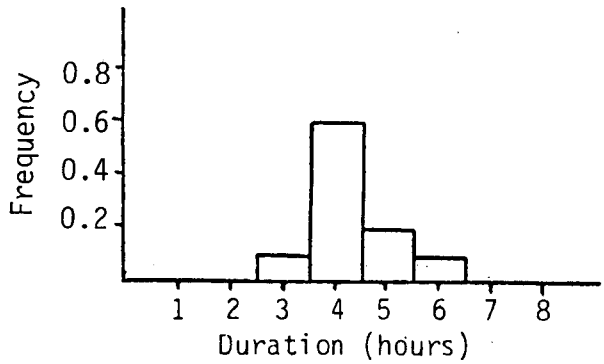
   a. Channel checks are performed every shift (8 hours). A channel check is a qualitative determination of acceptable operability by observation of the instrument behavior during operation.

   b. Channel functional tests are performed monthly. A channel functional test is the injection of a simulated signal(s) into the channel to verify operability, including alarm and/or trip initiating action.

   c. Channel calibration for most instrumentation loops is performed during refueling outages. Channel calibration is the adjustment of channel output(s) in such a manner that it responds, within acceptable range and accuracy, to known values of the parameter(s) which the channel monitors. Calibration encompasses the entire channel (including all channel outputs) and also includes the channel functional test.

2. The reactor protection logic channels are periodically tested to satisfy plant technical specification requirements as follows. Logic channel functional tests are performed monthly. A logic channel functional test is the application of input signals, or the operation of relays, or switch contacts in all the combinations required to produce the required decision outputs including the operation of all actuation devices. For the reactor protection

system logic channels, the actuated devices include the reactor trip breakers. During the logic channel test, the bypass reactor trip breaker for the logic channel being tested is racked into position, exercised, and closed. Testing of the channel then proceeds to the final actuation device, the reactor trip breaker. Successful completion of this testing requires the development of a trip signal and this trip signal must appear at the reactor trip breaker. This testing normally requires 4 hours per channel with a range of 3 to 6 hours. The histogram presented below is based on discussions with plant personnel and shows the frequency distribution of test duration.



The mean duration from this histogram is 4.3 hours. Since the tests are performed once per month, this histogram leads to an unavailabilty distribution characterized by the following mean and variance:

Mean: $\frac{4.3 \text{ hours/month}}{720 \text{ hours/month}} = 5.97 \times 10^{-3}$ Single train unavailability due to test

Variance: 1.18×10^{-6}

3. The rod drive mechanisms and rod control cluster assemblies are exercised biweekly if no other rod insertion has occurred during the past 2-week period to ensure freedom of movement and to satisfy technical specification requirements.

1.5.2.2.2.2.7 Operator Interaction. Operator action to manually scram the plant is excluded from this analysis. Operator errors during calibration are quantified in Section 1.5.2.2.2.4.4, Common Cause Failure.

1.5.2.2.2.2.8 Common Cause Effect. The logic and instrumentation cabinets associated with the RPS are located in the control room behind the flight panels at Indian Point 2.

The reactor trip breakers and the rod drive motor generator sets are located at Elevation 33' of the control building.

Common generic components of the RPS are: (1) supplied by the same manufacturers, (2) subject to common test and maintenance procedures, and (3) have common susceptibility to secondary causes of failure (grit, moisture, vibration, etc.).

Further discussion of the effects of common cause failures on system failures is presented in Section 1.5.2.2.2.4.4 of this analysis.

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1.5.2.2.2.3 Logic Model.

1.5.2.2.2.3.1 Top Event. The fault tree is developed for the event "Reactor Protection System Failure to Scram." This event appears in the small LOCA event tree and all transient event trees.

1.5.2.2.2.3.2 System Fault Tree. Figure 1.5.2.2.2-5 presents the fault tree developed for the RPS. The tree identifies the hardware failures that must occur to fail the RPS. Discussion of these events is presented in Section 1.5.2.2.2.4 of this study.

The fault tree was developed for the event "Turbine Trip Without Bypass." All other transient events which require RPS action have similar fault tree logic.

1.5.2.2.2.3.3 Fault Tree Coding. Table 1.5.2.2.2-5 identifies the basic events and the basic event coding used in this analysis. The failure rates associated with the basic events are also included in Table 1.5.2.2.2-5.

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1.5.2.2.2.4 Quantification.

1.5.2.2.2.4.1 Single Failures. Three single failures are identified and defined for the RPS. These defined events are:

1. Reactor Core Misalignment Causes Rods Not to Insert. For the small LOCA and the transient event trees that require RPS action, the probability of this failure is quantitatively insignificant ($<<10^{-8}$) and does not contribute to system failure to scram.

2. Wiring Fault Provides Sufficient Power to Hold RCCAs in Position. The rod drive motor generator sets supply three-phase, nonsynchronous power to the rod control panels through the reactor trip breakers. No power source exists at the plant that is capable of being paralleled with the rod control power. In addition, the bus itself is completely metal enclosed from the rod drive motor generator sets to the rod control panels. For these reasons, the probability of this failure is quantitatively insignificant ($<<10^{-8}$) and does not contribute to system failure to scram.

3. Rod Control Cluster Assemblies Fail to Insert. In NUREG/CR-1331 a review of Licensee Event Reports for control rods and drives is presented. There have been three reported failures of RCCAs to fully insert* during a reactor scram condition in Westinghouse pressurized water reactors during the period reviewed. Using the data from NUREG/CR-1331, there were 50,987 individual rod demands (number of rods per plant times the number of scrams per plant) in this period. This data is used to establish a prior population variability distribution. For Indian Point 2 there have been 0 failures in 6,784 demands (through June 1980). A population variability analysis and update based on Indian Point 2 experience was performed. The results of this procedure lead to the following mean and variance for the rate of failure of an individual RCCA to insert on demand:

   Mean: 3.38×10^{-5}

   Variance: 1.72×10^{-9}

   Using the binomial probability theorem, the probability of any two or more RCCAs not fully inserting on demand is:

   Mean: 3.77×10^{-6}

   This result describes the random coincident failure of two or more rods. However, failure of two RCCAs to insert does not constitute failure to scram. In fact, failure of 10 to 20 RCCAs to fully insert would probably not constitute failure to scram as those RCCAs that do insert may reduce power sufficiently to allow mitigation of the accident.

*Fully insert is defined as inserting to > 96% position.

With respect to common cause failures, only failures of the RCCAs themselves are considered. The logic, instrumentation, and the trip breaker contributions to common cause failure are considered in Section 1.5.2.2.2.4.4. There has not been a multiple rod failure to insert during scram in Westinghouse reactors (from NUREG/CR-1331, zero multiple rod failures in 1,110 total scrams and zero multiple rod failures in 50,987 individual rod scrams). No credible mechanism by which such a common cause failure could occur for the events of interest (external events, such as earthquake, are treated separately in this study) can be envisioned. Mechanisms for common cause failures such as wearout or manufacturing defects are possible; however, the following points are important:

a. During refueling, the drive mechanisms and RCCAs are inspected and replaced if excessive wear or other unusual conditions are present.

b. If these mechanisms for failure exist they would have been noted in the plants that have been online longer than Indian Point 2.

For these reasons, the probability of multiple rod failures to insert during scram is assigned the value obtained from the binomial theorem for failure of two or more rods to fully insert on demand:

Mean: 3.77×10^{-6}

Variance: 4.33×10^{-10}

1.5.2.2.2.4.2 Double Failures. Double failures consist of failures in RPS trains A and B. The quantification for a single train and the train combinations are presented below.

Train A consists of the following basic components:

- Reactor trip breaker A--RTA.
- Reactor trip bypass breaker A--BYA.
- Logic channel A, which consists of the logic matrix and trip relays for train A.
- Wiring for the logic channel and trip breakers.

Train B contains similar components.

Note: The analog instrumentation system is common to trains A and B. Discussion of the effect of failure of the instrumentation portion of the RPS is discussed in Section 1.5.2.2.2.4.2.6.

The train arrangement simplifies the calculations for system failure. A train can be thought of as a block of series connected basic events, with failure of any one basic event resulting in train failure. Quantification of the basic events is presented in the following.

1. RTA fails closed. Based upon a review of plant data, the frequency of this event occurring is:

   Mean: 4.67×10^{-4}

   Variance: 8.51×10^{-7}

2. BYA fails closed. This event is separate from the test or maintenance condition where the bypass breakers are intentionally closed to facilitate testing.

   Because the bypass breakers are manually operated, normally open, racked out, and key locked in the rack out position, no frequency of failure is assigned.

3. Logic Channel A failures. This event consists of logic matrix failures or trip relay failures.

   a. Trip relay failures. The mean and variance for the frequency of failing to open for a trip relay are:

      Mean: 6.28×10^{-6}

      Variance: 2.49×10^{-11}

      Failure of a single trip relay to open on demand does not cause system failure. Although the relays for a particular scram are arranged in parallel, diversity of scram signals requires coincident failure of two or more relays in series. This results in a mean and variance for trip relay contribution to RPS failure of:

      Mean: 6.33×10^{-11}

      Variance: 2.28×10^{-20}

   b. Logic matrix failures. The logic matrices for the reactor trip signals consist of groupings of contacts which are opened by relays actuated by the analog instrumentation system. Failure of these relays to open will result in matrix failure. From Table 1.5.2.2.2-2, the minimum number of relay failures that will cause failure of a logic matrix is two for the small LOCA and transient events under consideration. These relays are similar to the reactor trip relays and the same mean and variance for two relays failing to open on demand is assigned.

Diversity of scram signals requires coincident failure of two or more logic matrices in order to fail the RPS logic. The coincident failure of two matrices occurs with a mean frequency of:

Mean: 2.68×10^{-20}

This value is insignificant when compared to other causes of RPS failure.

4. Wiring faults leading to RPS failure. Two general locations exist for possible wiring faults that fail the RPS.

   a. Wiring shorts to power. Undervoltage trip coil--a wiring short to power in the portion of the reactor trip circuit that supplies the undervoltage trip device could result in power being maintained to this trip device when a reactor trip is demanded. The distribution for this event is:

      Mean: 3.22×10^{-6} failures/hour

      Variance: 8.96×10^{-11}

      To determine the contribution to system failure, a frequency of failure per hour must be converted to a frequency of failure on demand. The fault detection time for this event is one-half the test cycle (t = 360 hours). This results in the following frequency of failure on demand due to wiring shorts to power:

      Mean: 1.16×10^{-3}

      Variance: 1.16×10^{-5}

   b. Wiring shorts to ground. The RSS postulated nine possible locations where a short to ground would result in failure of the RPS. Because the RPS logic and breaker power supplies are ungrounded, there is no location where a single wiring fault to ground results in failure of the system. To set up a parallel loop which would bypass contacts and maintain current flow, at least two shorts to ground in the correct location are required. The distribution for this event is:

      Mean: 7.52×10^{-6} failures/hour

      Variance: 4.88×10^{-10}

      To determine the contribution to system failure, a frequency of failure per hour must be converted to a frequency of failure on demand. Again, a fault detection time of t = 360 hours (one half of the test cycle) is used. This results in the following

distribution for the frequency of failure due to a single wiring short to ground:

Mean: 2.71×10^{-3}

Variance: 5.63×10^{-5}

And for two faults to ground:

Mean: 5.77×10^{-5}

Variance: 3.35×10^{-6}

And for nine possible locations:

Mean: 5.20×10^{-4}

Variance: 2.71×10^{-4}

The total contribution to system failure due to wiring faults is the sum of wiring faults to power and wiring faults to ground, which is:

Mean: 1.68×10^{-3}

Variance: 5.41×10^{-5}

5. Train A failure is represented by the following equation:

$$Q_{\text{Train A}} = Q_{RTA} + Q_{BYA} + Q_{\text{Logic}} + Q_{\text{Wiring to Power}} + Q_{\text{Wiring to Ground}}$$

$$Q_{\text{Train A}} = 2.15 \times 10^{-3}$$

$$\beta^2_{\text{Train A}} = 5.11 \times 10^{-5}$$

The distribution for train B is the same. The doubles contribution to RPS failure is:

$$Q_{AB} = (Q_A)(Q_B) = 9.62 \times 10^{-6}$$

$$\beta^2_{AB} = 6.62 \times 10^{-10}$$

6. The frequency of failure of the instrumentation channels must be included with this value. The frequency of a single instrument channel failing to provide a trip signal is $\lambda = 1 \times 10^{-4}$ failures per demand. This value is taken as a median and assigned an error

factor of 10 to express the uncertainty. Taking the values obtained with this error factor as the 5th and 95th percentiles, the distribution for a single instrument channel failure is:

Mean: 2.66×10^{-4}

Variance: 4.32×10^{-7}

As was the case for logic matrices failure, at least two out of three instruments must fail to cause a single scram signal failure. For two instruments failing, the mean and variance are:

Mean: 4.61×10^{-7}

Variance: 1.43×10^{-10}

Scram signal diversity requires failure of two or more different instrumentation groups. For failure of two instrumentation groups, the mean value is:

Mean: 1.43×10^{-10}

This is insignificant compared to other causes of RPS failure.

1.5.2.2.2.4.3 Test and Maintenance Failure. The test contribution to RPS failure is obtained by multiplying the unavailability of a single train due to test times the frequency of wiring faults in the other logic train. This results in a mean and variance of:

Mean: 3.10×10^{-6}

Variance: 1.64×10^{-9}

For the total system contribution, the contribution of a single train must be doubled. This results in the following mean and variance:

Mean: 6.20×10^{-6}

Variance: 6.56×10^{-9}

Maintenance on the RPS is not quantified for the following reasons:

- The components requiring the most maintenance are those located in the logic channel. Before performing maintenance on a component in the logic channel, the associated trip relay is placed in the "tripped" condition which sets up part of the logic matrix required for scram signal development. This maintenance does not affect the RPS analysis.

- Maintenance on the reactor trip breakers occurs infrequently. If one maintenance act per year lasting for 4 hours is assumed, the resulting unavailability due to maintenance is 1/12 the contribution of testing. This does not significantly affect the results of the system analysis.

1.5.2.2.2.4.4 Common Cause Failure.

1.5.2.2.2.4.4.1 Instrument channel miscalibration. There is a potential for common miscalibration errors applied to all instruments of a particular set. During the periodic calibrations, a single technician or group of technicians performs the tests necessary to ensure instrument accuracy. These tests are usually performed sequentially among identical channels. This leads to an extremely close coupling between the acts. However, most calibration activities, even if performed in error, do not result in an instrument that fails to provide a trip. In addition, the diversified types of instruments that provide trip signals limit the effect of these common cause miscalibrations. If the value of a single instrument channel failing, 2.66×10^{-4}, is taken as the frequency of common cause miscalibration of a set of instruments, failure of two sets of instrumentation due to miscalibration of this type would result in a mean and variance of:

Mean: 4.61×10^{-7}

Variance: 1.43×10^{-10}

This value is used as the frequency of common cause miscalibration errors.

1.5.2.2.2.4.4.2 Monthly logic train testing. It can be seen from the fault tree that, during the monthly logic channel testing, a single logic channel failure can cause failure of the RPS. Both trains of logic are tested sequentially which, in principle, could introduce common cause coupling between the channels. However, the logic testing does not involve the changing of trip setpoints or logic arrangements. For this reason, these testing failures are treated as independent events which do not affect system unavailability.

1.5.2.2.2.4.5 System Quantification. The probability of the RPS failing to scram on demand is presented in the following:

$$Q_{RPS} = Q_{Singles} + Q_{Doubles} + Q_{Test\ and\ Maintenance} + Q_{Common\ Cause}$$

$$Q_{RPS} = 2.01 \times 10^{-5}$$

$$\beta^2_{RPS} = 6.78 \times 10^{-9}$$

Table 1.5.2.2.2-6 summarizes the results of the quantification of the RPS by cause.

TABLE 1.5.2.2.2-1

INDIAN POINT 2 RESULTS TABLE - REACTOR PROTECTION SYSTEM FAILURE TO SCRAM

Contributors to System Failure	Mean	Variance	5th Percentile	95th Percentile	Median	RSS (point estimates)
Singles	3.8×10^{-6}	4.3×10^{-10}	1.9×10^{-8}	1.0×10^{-5}	5.7×10^{-7}	1.7×10^{-5}
Doubles	9.6×10^{-6}	6.6×10^{-10}	2.3×10^{-8}	4.0×10^{-5}	7.5×10^{-7}	5.4×10^{-6}
Test and Maintenance	6.2×10^{-6}	6.6×10^{-9}	4.4×10^{-10}	9.6×10^{-5}	1.2×10^{-7}	1.2×10^{-5}
Common Cause	4.6×10^{-7}	1.4×10^{-10}	5.2×10^{-11}	6.7×10^{-7}	9.0×10^{-9}	ε*
System Failure to Scram on Demand	2.0×10^{-5}	6.8×10^{-9}	4.3×10^{-7}	7.0×10^{-5}	4.2×10^{-6}	3.4×10^{-5}

*Epsilon used in the RSS to signify insignificant contributors to failure.

TABLE 1.5.2.2.2-2

INDIAN POINT 2 REACTOR PROTECTION SYSTEM TRIP SIGNALS

Reactor Trip	Coincidence Circuitry and Interlocks	Setpoint*	Comments
1. Manual	1/2, no interlocks	NA	
2. High power range neutron flux	2/4, low setpoint interlocked with P-10	High ≤ 109% power Low ≤ 25% power	High and low settings. Manual block and automatic reset of low setting by P-10.
3. Overtemperature ΔT	2/4, no interlocks	ΔT > program	
4. Overpower ΔT	2/4, no interlocks	ΔT > program	
5. Low pressurizer pressure	2/4, blocked by P-7	≥ 1,700 psig	
6. High pressurizer pressure	2/3, no interlocks	≤ 2,385 psig	
7. High pressurizer water level	2/3, interlocked with P-7	≤ 92% span	

*< or > reflects the conservatism between the technical specification limit, the number identified, and the allowable setpoint.

TABLE 1.5.2.2.2-2 (continued)

INDIAN POINT 2 REACTOR PROTECTION SYSTEM TRIP SIGNALS

Reactor Trip	Coincidence Circuitry and Interlocks	Setpoint	Comments
8. Low reactor coolant flow	2/3 signals per loop, interlocked with P-7, P-8	$\geq$ 90% flow	Blocked below P-7. Low flow in one loop permitted below P-8.
9. Monitored electrical supply to reactor coolant pumps			
9a. Undervoltage	2/4, interlocked with P-7	$\geq$ 70% normal	1/bus
9b. Underfrequency	2/4, interlocked with P-7	$\geq$ 57.5 cps	2/4 underfrequency signals will trip all reactor coolant pumps and indirectly activate reactor trip. Blocked below P-7.
9c. Reactor coolant pump breakers	Interlocked with P-7 and P-8	-	Blocked below P-7. Open breaker in one loop permitted below P-8.
10. Safety injection signal	2/3 low pressurizer pressure 2/3 high containment pressure 2/3 differential steam line pressure - low compared to two high, four channels 2/4 high steam flow in coincidence with: 2/4 low T_{avg} or 2/4 low steam line pressure 1/2 manual	$\geq$ 1,700 psig $\leq$ 2.0 psig $\leq$ 150 psid program $\geq$ 540°F $\geq$ 600 psig	Trips main feedwater pumps. Closes all feedwater control valves. Closes feedwater isolation valves and initiates phase A isolation.

TABLE 1.5.2.2.2-2 (continued)

INDIAN POINT 2 REACTOR PROTECTION SYSTEM TRIP SIGNALS

Reactor Trip	Coincidence Circuitry and Interlocks	Setpoint	Comments
11. Turbine generator trip	2/3 low auto stop oil pressure interlocked with P-7 or all stop valves closed		
12. Low feedwater flow	1/2 steam/feedwater flow mismatch in coincidence with 1/2 low steam generator water level per loop	$\geq$ 60% flow and $\geq$ 30% span	
13. Low-low steam generator water level	2/3, per loop	$\geq$ 5% span	
14. Intermediate range neutron flux	1/2, manual block permitted by P-10	$\leq$ 25% power	Manual block and automatic reset.
15. Source range neutron flux	1/2, manual block permitted by P-10 and P-6	$\leq 10^5$ cps	Manual block and automatic reset.

TABLE 1.5.2.2.2-3

INDIAN POINT 2 LOGIC MATRIX TO REACTOR TRIP RELAY MATCHING

Trip Relay Number*	Reactor Trip Logic Matrix
RT1,2	Intermediate range trip Source range trip Power range low level trip
RT3,4	Overtemperature ΔT trip Overpressure ΔT trip Safety injection trip
RT5,6	Steam generator low-low level trip
RT7,8	Steam generator feedflow/level mismatch trip
RT9,10	High pressurizer level trip Power range high level trip High pressurizer pressure trip Low pressurizer pressure trip
RT11,12	Low loop flow trip Manual trip
RT13,14	Undervoltage RCP breakers trip
RT15,16	Turbine trip

*See Figure 1.5.2.2.2-2 or 1.5.2.2.2-3 for the arrangement of the trip relays in the logic matrix.

TABLE 1.5.2.2.2-4

INDIAN POINT 2 INSTRUMENT AND LOGIC POWER SUPPLIES

Load Center	Loads
Instrument Bus 21	Reactor Analog Protection Channel 1 Nuclear Instrument Channel 1 Steam Generator Analog Channel 1 Reactor Protection Cabinets E-6, F-6 Containment Instrument and Protection Channel
Instrument Bus 23	Reactor Protection Analog Channel 3 Nuclear Instrument Channel 3 Safeguard Relay Test (F-7, E-8) Reactor Protection Cabinets E-4, F-4
DC Power Panel 22, Circuit 11	Reactor Trip Breaker Open/Close Circuits Logic B (RTB and BYA)
Instrument Bus 22	Reactor Analog Protection Channel 2 Nuclear Instrument Channel 2 Steam Generator Analog Channel 2 Reactor Protection Cabinets E-5, F-5 Reactor Protection Logic Status Lights Containment Instrument and Protection Channel 2
Instrument Bus 24	Reactor Protection Analog Channel 4 SIS Instrument Analog Nuclear Instrument Channel 4 Reactor Protection Cabinets E-3, F-3
DC Power Panel 21, Circuit 5	Reactor Trip Breaker Open/Close Circuits Logic A (RTA and BYB)

TABLE 1.5.2.2.2-5

INDIAN POINT 2 BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data					Comments
		Mean	H/D*	Variance	MTTR	Reference	
Reactor core misalignment causes rods not to insert	1EDCOREF	$<< 10^{-8}$	-	-	-	-	Developed in text
Rod control cluster assemblies fail to insert	1ED0001F	3.77×10^{-6}	D	4.33×10^{-10}	-	NUREG/CR1331	Developed in text
Wiring fault provides sufficient power to hold RCCAs in position	1WR0001Q	$<< 10^{-8}$	-	-	-	-	Developed in text
Reactor trip breaker, RTA, fails closed	1CB0005Q	4.67×10^{-4}	D	8.51×10^{-7}	-	45	
Reactor trip breaker, RTB, fails closed	1CB0004Q	4.67×10^{-4}	D	8.51×10^{-7}	-	45	
Trip bypass breaker, BYA, fails closed	1CB0003C		D				Developed in text
Trip bypass breaker, BYB, fails closed	1CB0002C		D				Developed in text
Trip bypass breaker, BYA, closed for test	1CB0003X	5.97×10^{-3}		1.18×10^{-6}			Developed in text
Trip bypass breaker, BYB, closed for test	1CB0002X	5.97×10^{-3}		1.18×10^{-6}			Developed in text
No turbine trip signal	1TT0001S	4.61×10^{-7}	D	1.43×10^{-10}			Developed in text
No pressurizer high pressure signal	1PHPT00S	4.61×10^{-7}	D	1.43×10^{-10}			Developed in text
No pressurizer low level signal	1PLLT00S	4.61×10^{-7}	D	1.43×10^{-10}			Developed in text
No over temperature Δ T signal	1OTDT00S	4.61×10^{-7}	D	1.43×10^{-10}			Developed in text
Trip relay, RT3A, fails closed	1RE003AQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT3B, fails closed	1RE003BQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT4A, fails closed	1RE004AQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT4B, fails closed	1RE004BQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT9A, fails closed	1RE009AQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT9B, fails closed	1RE009BQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT10A, fails closed	1RE010AQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT10B, fails closed	1RE010BQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT15A, fails closed	1RE015AQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT15B, fails closed	1RE015BQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT16A, fails closed	1RE016AQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Trip relay, RT16B, fails closed	1RE016BQ	6.28×10^{-6}	D	2.49×10^{-11}		41	
Wiring faults in Logic A	1WRLOGAQ	1.73×10^{-3}	-	7.04×10^{-5}			Developed in text
(includes: short to power and shorts to ground)		3.22×10^{-6}	H	8.96×10^{-11}	36[illegible] hours	39	
		7.52×10^{-6}	H	4.88×10^{10}	360 hours	40	
Wiring faults in Logic B	1WRLOGBQ	1.73×10^{-3}	-	7.04×10^{-5}			Developed in text
(includes: short to power and shorts to ground)		3.22×10^{-6}	H	8.96×10^{-11}	360 hours	39	
		7.52×10^{-6}	H	4.88×10^{10}	360 hours	40	

*H = Hours; D = Demand

TABLE 1.5.2.2.2-6

CAUSE TABLE - INDIAN POINT 2 REACTOR PROTECTION SYSTEM, FAILURE TO SCRAM ON DEMAND

Cause	Mean	Variance	System Effect	Mean (RPS Failure to Scram)	Variance
Singles:					
Core misalignment	$<< 10^{-8}$	$<< 10^{-8}$	Failure to scram	$<< 10^{-8}$	$<< 10^{-8}$
Rod control wiring faults	$<< 10^{-8}$	$<< 10^{-8}$	Failure to scram	$<< 10^{-8}$	$<< 10^{-8}$
RCCAs fail to insert	3.77×10^{-6}	4.33×10^{-10}	Failure to scram	3.77×10^{-6}	4.33×10^{-10}
Single Train:					
Reactor trip breaker	4.67×10^{-4}	8.51×10^{-7}	Loss of one train, no system failure	-	
Trip bypass breaker	-	-	Loss of one train, no system failure	-	
Wiring faults (ground) (9)	5.20×10^{-4}	2.71×10^{-4}	Loss of one train, no system failure	-	
Wiring short (power)	1.16×10^{-3}	1.16×10^{-5}	Loss of one train, no system failure	-	
Logic failure	6.33×10^{-11}	2.28×10^{-20}	Loss of one train, no system failure	-	
TOTAL	2.15×10^{-3}	5.11×10^{-5}			
Doubles:					
Combinations of single train failures	9.62×10^{-6}	6.62×10^{-10}	Failure to scram	9.62×10^{-6}	6.62×10^{-10}
Test and Maintenance:					
Train in test and logic wiring faults (2)	6.20×10^{-6}	6.56×10^{-9}	Failure to scram	6.20×10^{-6}	6.56×10^{-9}
Common Cause:					
Instrumentation miscalibration	4.61×10^{-7}	1.43×10^{-10}	Failure to scram	4.61×10^{-7}	1.43×10^{-10}
System Failure to Scram on Demand				2.01×10^{-5}	6.78×10^{-9}

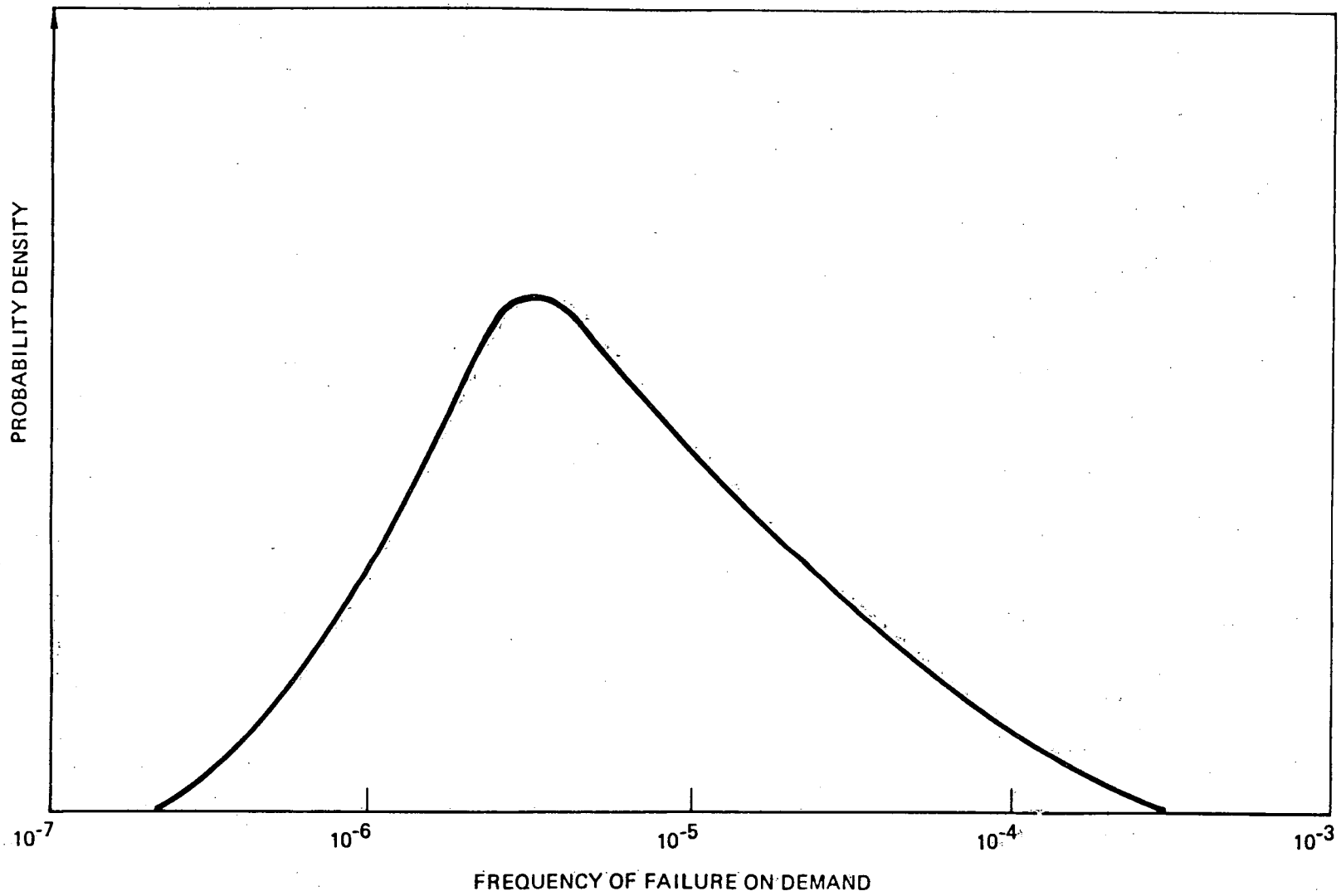

Figure 1.5.2.2.2-1. Probability Distribution of Indian Point 2 Reactor Protection System Failure on Demand

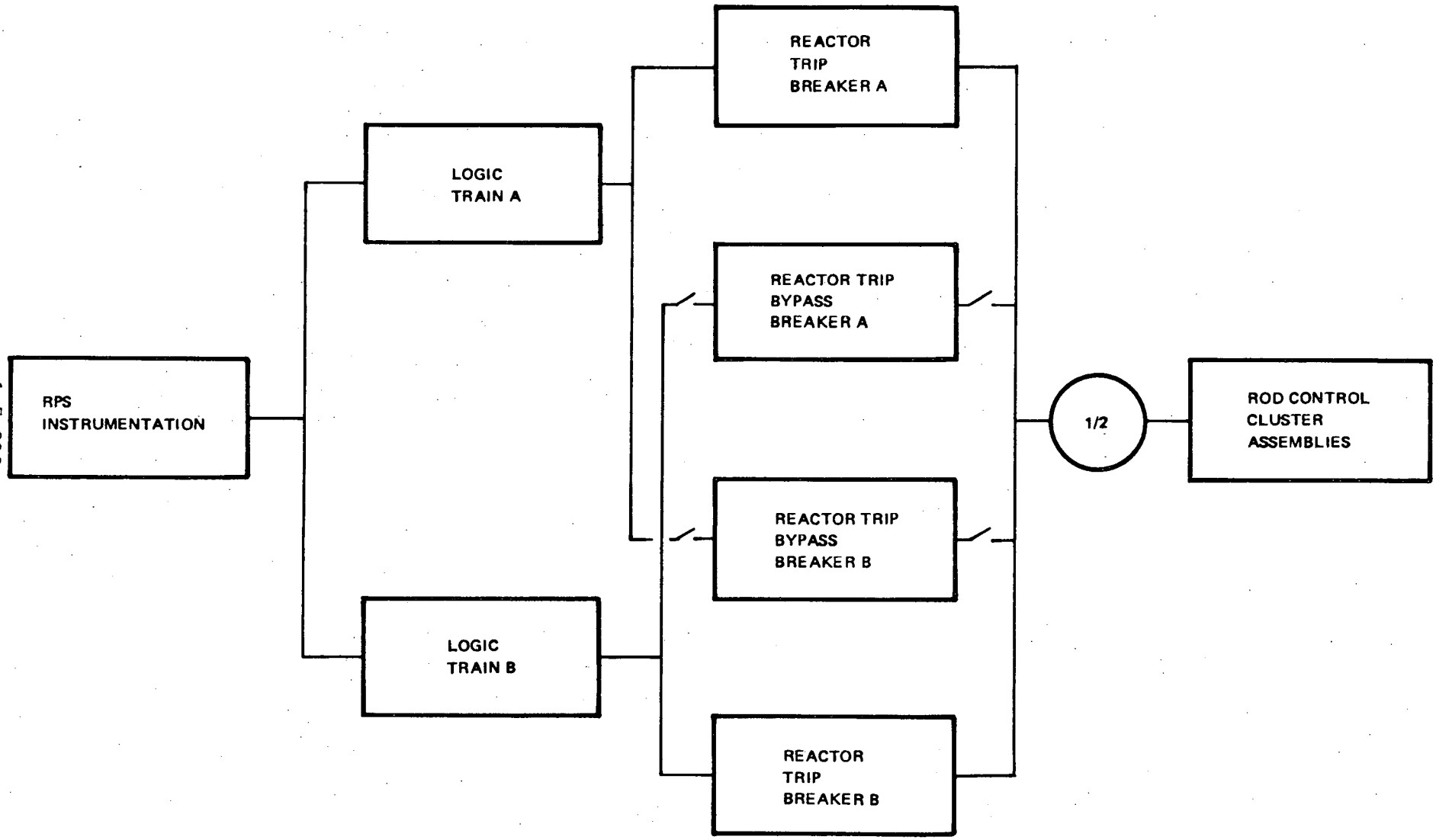

Figure 1.5.2.2.2-2. Indian Point 2 Simplified Block Diagram, Reactor Protection System

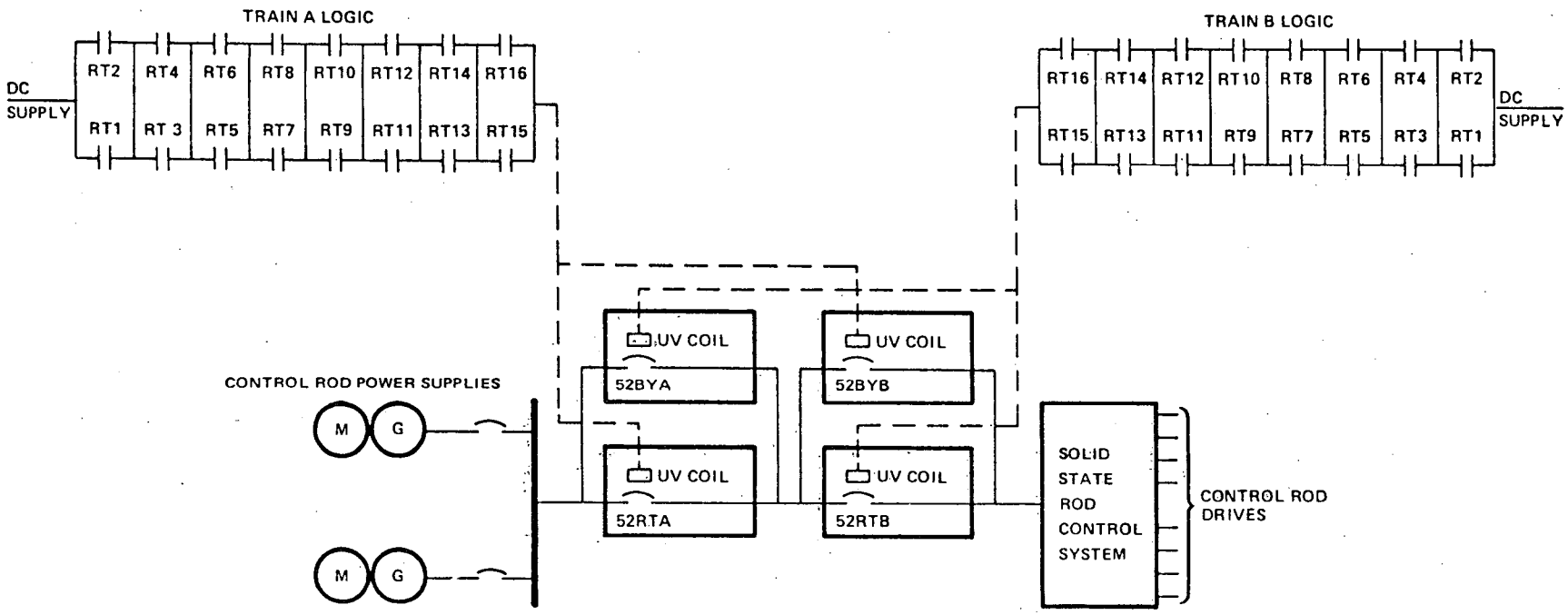

Figure 1.5.2.2.2-3. Indian Point 2 Reactor Protection System Simplified Arrangement

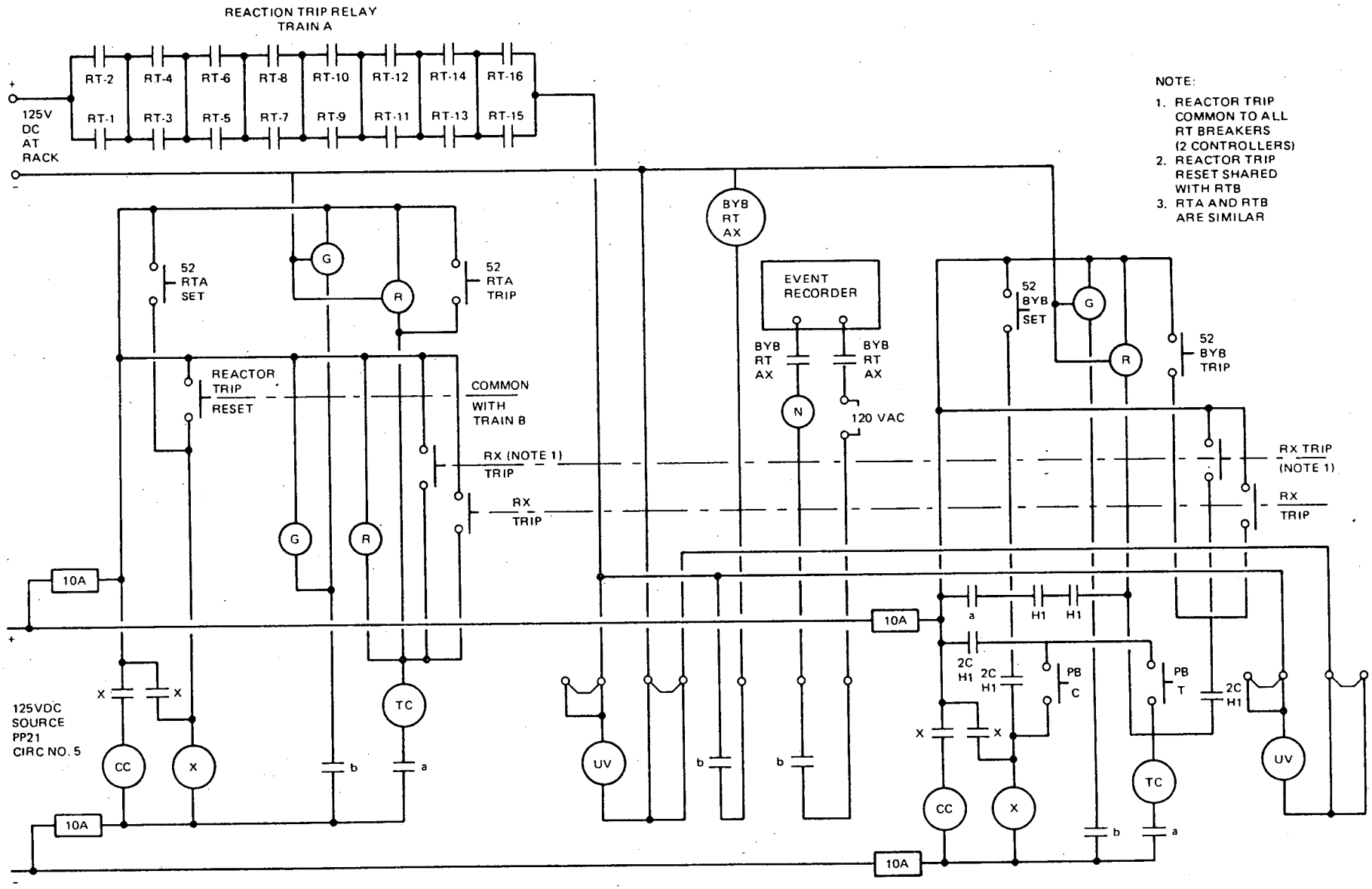

Figure 1.5.2.2.2-4. Indian Point 2 Reactor Trip Breaker Schematic

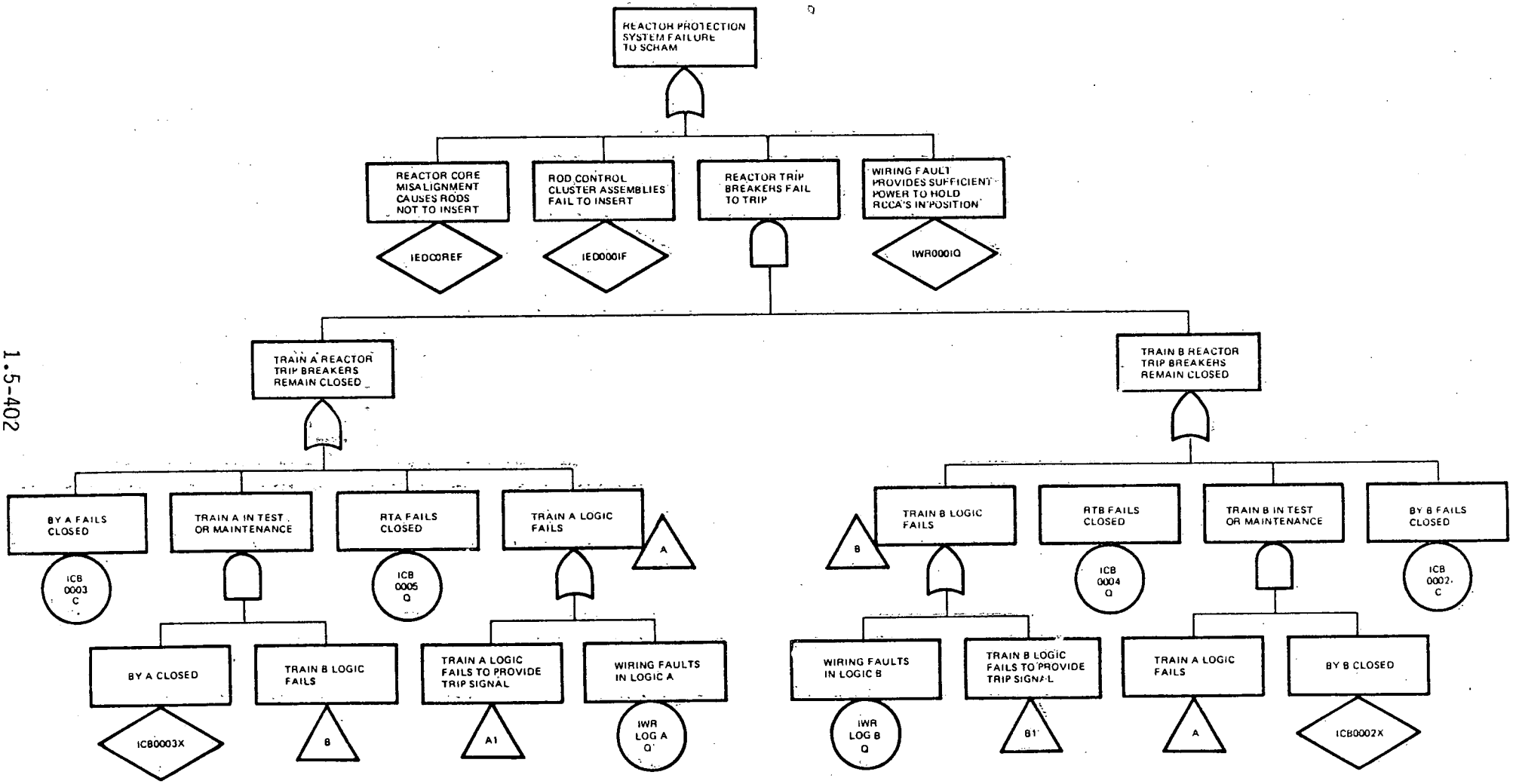

Figure 1.5.2.2.2-5. Indian Point 2 Reactor Protection System Fault Tree (Sheet 1 of 2)

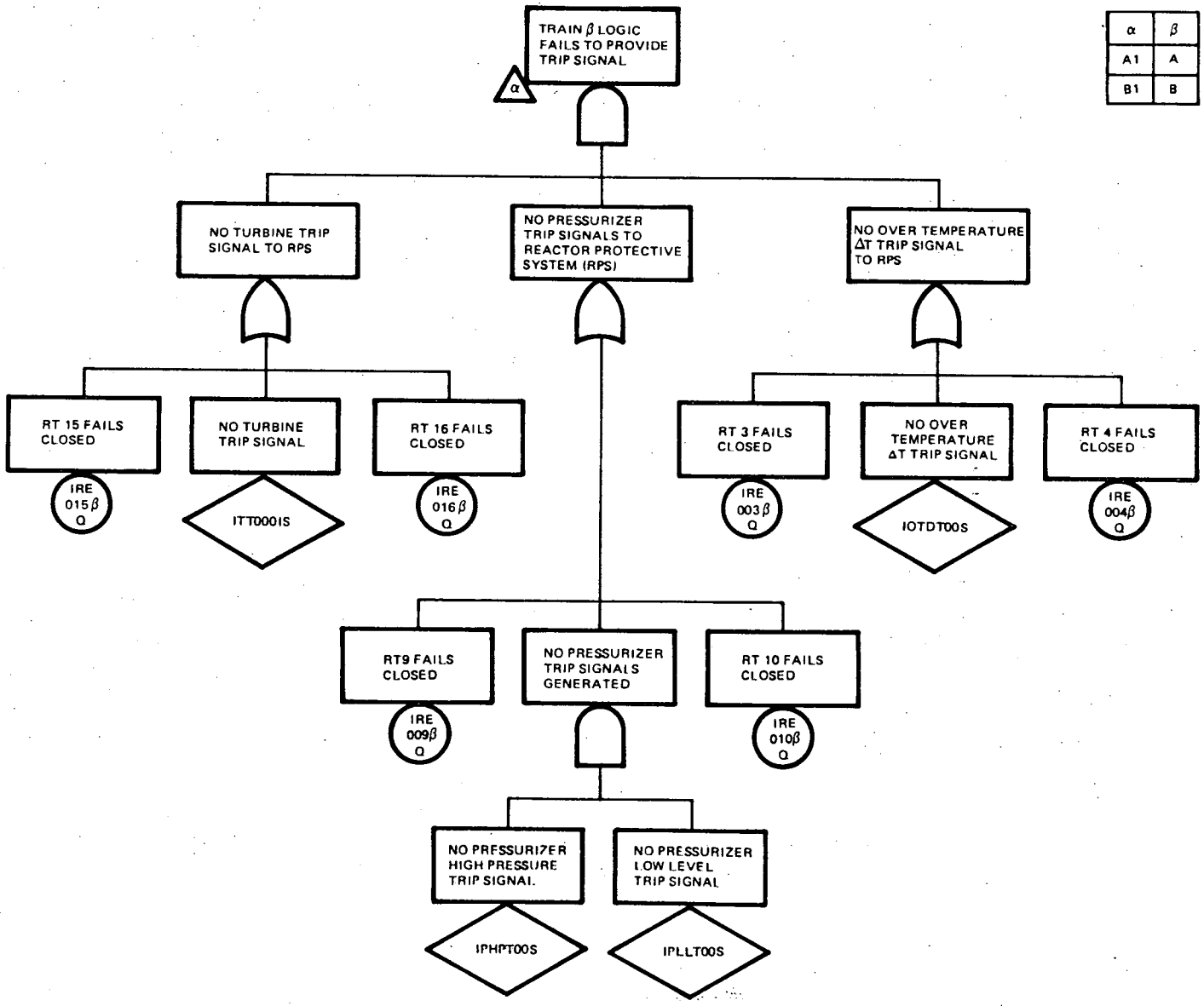

Figure 1.5.2.2.2-5. (Sheet 2 of 2)

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1.5.2.2.3 Indian Point 2 Safeguards Actuation System (Safety Injection and Containment Spray Actuation)

1.5.2.2.3.1 Summary.

1.5.2.2.3.1.1 Introduction. The safeguards actuation system (SAS) is evaluated for its ability to respond to various plant conditions and to deliver actuation signals to the designated engineered safeguards system (ESS) equipment during loss of coolant accident (LOCA) and other plant transient conditions.

The SAS detects breaks in the primary or secondary system and initiates operation of the components associated with the ESS.

This analysis is based upon the following assumptions:

- The system is in its normal operating mode prior to the initiating event.
- Operator action to manually initiate the system is not considered in this analysis. However, action to manually initiate the essential safeguards system equipment is considered at the event tree level.

The SAS is composed of two subsystems: safety injection (SI) actuation and containment spray (CS) actuation. Each subsystem is treated separately in this analysis. Failure of the safety injection actuation subsystem is defined as failure of both channels of safety injection logic or failure in the safety injection instrumentation. Failure of a single channel of safety injection logic includes failure to actuate any single equipment actuation relay.

Failure of the containment spray actuation subsystem is defined as failure of both channels of containment spray logic or failure in the containment spray instrumentation.

1.5.2.2.3.1.2 Results. Table 1.5.2.2.3-1 summarizes the results of the SAS analysis. This analysis revealed the following dominant contributors to SAS failure:

	Mean
• Safety Injection Actuation	
- Test of a single logic channel and random failure in the other logic channel	5.0×10^{-6} (80.6%)
- Random failures in both logic channels	1.2×10^{-6} (19.3%)
• Containment Spray Actuation	
- Test of a single logic channel and random failure in the other logic channel	5.0×10^{-6} (87.7%)

	Mean
- Failure of the high-high containment pressure instrumentation	3.8×10^{-7} (6.7%)
- Logic channel failures	3.0×10^{-7} (5.3%)

Table 1.5.2.2.3-1 includes a comparison of the results of this analysis with the results obtained in the Reactor Safety Study (RSS) analysis for similar systems.

1.5.2.2.3.1.3 Conclusions. No single failure which causes complete failure of the SAS was identified. Failures in two separate logic channels or instrumentation channels will result in failure of this system; however, operator action to start the required ESS equipment is independent of this system.

Probability distributions of systems failure on demand for safety injection and containment spray actuation are shown in Figure 1.5.2.2.3-1.

1.5.2.2.3.2 System Function and Description.

1.5.2.2.3.2.1 System Function. The SAS receives signals from various primary and secondary plant sensors, processes this input through logic matrices, and sends actuation signals to ESS equipment based upon plant conditions. The system serves to limit damage in the event of breaks in the reactor coolant system (RCS) or the secondary systems (main steam, feedwater, or steam generators).

Two separate and distinct functions are performed by this system: safety injection actuation and containment spray actuation. Each of these distinct functions causes several other actions to occur in the plant. This analysis includes all associated equipment from the process sensors (instrumentation) through the various auxiliary relays actuated by the system. Each function is analyzed separately; however, the sections on system description and operation discuss both functions.

1.5.2.2.3.2.2 System Description.

1.5.2.2.3.2.2.1 Initiation signals. Table 1.5.2.2.3-2 identifies the signals, logic arrangement, and trip setpoints which are used to initiate the safety injection or containment spray functions of this system. Figures 1.5.2.2.3-2 and 1.5.2.2.3-3 are simplified logic diagrams for system operation. The generation of the signals used by this system and the use of these signals follows.

1. High Steam Line Flow in Conjunction with Low Tavg or Low Steam Generator Pressure. This condition is indicative of a steam break downstream of the main steam isolation valves (MSIVs). Indications of a break in the general location are: high steam flow (to generate a signal, two of the four steam lines must indicate high steam flow) in conjunction with: (1) low T_{avg} (two of four sensors); or (2) low steam line pressure (two of four sensors). This signal initiates steam line isolation (closure of all four MSIVs) and automatic safety injection.

   A comparison circuit based on turbine first stage pressure is used to develop a varying setpoint signal which is used to generate the high steam line flow signal. Actual steam flow is compared with the programmed setpoint, and a trip signal is generated when actual steam flow exceeds the setpoint. To allow for startup, steam dump, and atmos- pheric relief valve operation when turbine first stage pressure is not a true indication of actual steam flow, the high steam line flow signal must be in coincidence with either a low T signal (sensed by primary loop resistance temperature detectors) generated by a two of four sensing network, or a low steam generator pressure signal generated by a two of four pressure sensing network.

2. Steam Line Differential Pressure. This condition indicates a steam break upstream of the MSIVs or a large feedwater line break. A break in either location results in the closure of the steam line nonreturn check valve (one in each steam line). Steam pressure

upstream of the check valve then decreases as the associated steam generator feeds the break directly. A comparison network is used in which this steam pressure is compared to the pressure in two of the three remaining intact steam generators. An automatic safety injection signal is generated when the pressure in the steam generator feeding the break decreases to the set value below the other two steam pressures.

3. Low Pressurizer Pressure. The pressurizer acts as a surge tank for the RCS. Pressurizer heaters cycle on and off to maintain RCS pressure within a specified band. Leakage from the RCS in excess of the pressurizer heater and charging pump capability for makeup results in a decrease in pressurizer pressure, and consequently RCS pressure. This signal serves to initiate automatic safety injection to protect the core from damage for RCS breaks and excessive leaks. Three channels of pressurizer pressure are monitored and an automatic safety injection signal is generated if any two of the three channels indicate low pressure. This trip is manually blocked by operator action when RCS pressure is below 1,900 psi during a plant shutdown. This block is automatically removed when RCS pressure increases above 1,900 psi and, if it is required, operator action would be required to reinitiate the block.

4. High Containment Pressure. In the event of a break in the RCS, or a steam line break inside the containment building, pressure inside the containment building would increase. The rate of the increase is dependent upon the size of the break. Containment pressure is monitored by three pressure transmitters located outside of the containment building. An automatic safety injection signal is generated when containment pressure exceeds the setpoint value in two of the three transmitter channels.

   NOTE: All of the trip relays associated with the instrumenta- tion discussed above are "deenergize to trip." That is, loss of power to an instrument channel causes the relays associated with that channel to trip, which results in one of the trip signals required for safety injection actuation.

5. High-High Containment Pressure. A high-high containment pressure is indicative of a large LOCA or a major steam line break inside the containment building. Containment pressure is monitored by six pressure transmitters located outside the containment building in the piping penetration areas. The output of these transmitters is divided into two groups of three. When containment pressure exceeds the high-high setpoint, a signal is developed which energizes the relays associated with that channel. Two out of three channels in both groups are required to initiate automatic containment spray actuation. In addition to the automatic containment spray signal, a main steam line isolation signal is sent to close the MSIVs and an automatic safety injection signal is developed.

The tripping of any of the input channels described previously is indicated on supervisory panel "SO" in the control room. In addition, the following channel trips will result in alarms at the locations noted:

Tripped Channels	Alarm	Location
1. High Steam Line Flow	High steam line flow SI	Safeguards panel
2. Steam Line Differential Pressure	Steam line ΔP SI	Safeguards panel
3. Pressurizer Pressure	Pressurizer low pressure channel trip	RCS supervisory panel
4. High Containment Pressure	High containment pressure SI channel trip	Safeguards panel
5. High-High Containment Pressure	High-high containment pressure (spray) channel trip	Safeguards panel

6. Manual Initiation Signals. In addition to the automatic signals described above, safety injection or containment spray may be initiated by the operators in the control room.

Manual safety injection is accomplished using the red manual safety injection pushbuttons on panel SB2 in the control room. Depressing one of these pushbuttons initiates the minimum required ESS equipment. Both pushbuttons must be depressed to initiate all ESS equipment. Manual spray actuation is accomplished by depressing the red manual spray actuation pushbuttons on safeguards panel SB1 in the control room. Depressing one spray actuation pushbutton initiates one train of spray equipment.

1.5.2.2.3.2.2.2 Essential safeguards equipment actuation. All or portions of the following signals are actuated as a result of the signals discussed previously:

- Reactor Trip
- Feedwater Isolation
- Unit Trip and 6,900V Bus Transfer
- Containment Ventilation Isolation
- Containment Isolation Phase A
- Containment Isolation Phase B
- Containment Spray Actuation
- Safety Injection
- Isolation Valve Seal Water System
- Containment Cooling and Filtration
- Steam Line Isolation

- Emergency Diesels
- Service Water System
- Auxiliary Feedwater

Figure 1.5.2.2.3-4 presents the functional relationships between the various initiation signals and the actuated equipment. A discussion of the signals and the relationships follows.

1. Safety Injection Signal. The automatic safety injection signal is developed by the actuation of one of the five process input signals previously described. The automatic safety injection signal causes the following actions to occur:

   a. Reactor Trip
   b. Feedwater Isolation
   c. Unit Trip and 6,900 Volt Bus Transfer
   d. Containment Ventilation Isolation
   e. Containment Isolation Phase A
   f. Control Room Ventilation Isolation
   g. Safeguards Sequence

   The manual safety injection signal does not actuate containment isolation phase A; however, the other six actions do occur as a result of manual safety injection. The reasons for these signals and further actuation signals generated by these signals are:

   a. Reactor Trip. The reactor is tripped to reduce power production and to aid in minimizing the consequences of the accident.

   b. Feedwater Isolation. The feed system is isolated to minimize the severity of steam break accidents.

   c. Unit Trip and 6.9 kV Bus Transfer. The turbine is tripped to stop the demand for power. The 6.9 kV buses (1 through 4) are transferred to buses 5 and 6 to ensure continued power to essential equipment.

   d. Containment Ventilation Isolation. This signal causes isolation of the pressure relief line, the purge supply line, and the purge exhaust line to eliminate leakage from the containment through these lines.

   e. Containment Isolation Phase A. This signal isolates all fluid system containment penetrations which will not aid in minimizing the consequences of an accident. In addition, this signal causes operation of the isolation valve seal water system which provides a water seal against containment leakage.

   f. Control Room Ventilation Isolation. This signal changes the control room air conditioner to the incident mode.

g. Safeguards Sequence. This signal causes the following actions:

(1) Commands all three diesel generators to start, provided controls are in automatic, and opens the service water bypass gates.

(2) Sends a tripping signal to all loads on the 480V buses except MCC26A and MCC26B and the diesel generator output breakers. If there is no undervoltage condition (offsite power available), then MCC24, MCC29, and MCC211 remain connected and are not stripped on SI.

(3) Trips the 480V bus tie breakers.

(4) Sends a starting signal to the component cooling booster pumps and automatic signals to allow for injection path lineup.

(5) After a 3-second time delay, and in the absence of an undervoltage condition on the respective 480V buses, sends sequence signals to start the safeguards equipment on the four 480V bus. If outside power is lost, the sequence signal to the affected 480V buses is delayed until voltage is restored by the diesel generators. If the SI signal is reset prior to restoring voltage to the bus, the SI equipment will not automatically start.

2. Containment Spray. The containment spray actuation signal is developed by the two-out-of-three-twice logic for high-high containment pressure or by depressing the two manual actuation pushbuttons (one button for each train). This signal causes actuation of the spray equipment and containment isolation phase B. Sodium hydroxide addition is delayed for 2 minutes after spray actuation to allow the operator time to cancel this addition if it is not needed. The cancel pushbutton only affects the sodium hydroxide addition system.

1.5.2.2.3.2.2.3 Safeguards actuation manual resets. The various actuation signals pass through memory devices that preserve the signal to allow the functions to go to completion. Manual reset pushbuttons are provided to allow for operator flexibility during recovery. The action of these pushbuttons is described below:

- Safety Injection Reset. Two manual pushbuttons are located at supervisory panel SB2. These pushbuttons, one for each logic channel, allow resetting of the equipment actuation relays. Resetting of the relays does not remove equipment from operation. These reset pushbuttons are interlocked with a timing device that prevents resetting for 2 minutes after actuation. Once the signal is reset, it will not be reactuated by an automatic signal until all initiation signals have been cleared. Manual safety injection may be initiated at any time.

- Containment Isolation Phase A Reset. Two manual pushbuttons located at supervisory panel SN allow resetting of this actuation signal. Once reset, reactuation will be inhibited until after the automatic safety injection signal is reset. Manual containment isolation phase A may be initiated at any time.

- Containment Ventilation Isolation Reset. Two manual pushbuttons located at supervisory panel SN allow resetting of this actuation signal. However, since there is no reset lock-in relay, either automatic or manual containment ventilation isolation may be initiated or reactivated at any time.

- Containment Isolation Phase B Reset. Two manual pushbuttons located at supervisory panel SN allow resetting of this signal. Once reset, reactuation is inhibited until after the spray initiation signal has been reset. Manual containment isolation phase B may be initiated at any time.

- Spray Reset. Two manual pushbuttons located at supervisory panel SB1 allow resetting of this signal. Once reset, automatic reactuation is inhibited until after the spray initiation signal has cleared. Manual spray injection may be initiated at any time.

1.5.2.2.3.2.2.4 Safeguards logic channels. There are two channels of actuation logic in the SAS. These logic channels require DC power for proper operation. The power supplies for the logic channels are presented in Section 1.5.2.2.3.2.3 of this analysis. Table 1.5.2.2.3-3 identifies the logic relays and the equipment actuated by each relay.

Each logic channel contains six master relay-slave relay sets. These relay sets are:

- Safety Injection Automatic Actuation
- Safety Injection Manual Actuation
- Containment Ventilation Actuation
- Containment Isolation Phase A
- Containment Isolation Phase B
- Containment Spray Actuation

The master relays are special relays which contain operating and reset coils. The master relay is normally deenergized. When the proper logic matrix is made up, the operating coil will be energized by auxiliary contacts and demand the various safeguards equipment to operate. The master relays, via a mechanical latching mechanism, and the slave relays will remain in the actuated position until the master relay is reset (reset coil is energized). The reset signal is applied through the manual reset pushbuttons described in Section 1.5.2.2.3.2.2.3.

The safeguards logic relays are located in relay racks adjacent to the reactor trip logic relay panels. These relays are arranged in matrices which develop the necessary logic for safeguards initiation. A typical logic matrix and master relay slave relay layout is shown in

Figure 1.5.2.2.3-5. Each logic relay is fed from a safeguards actuation bistable located at the analog racks. The signal from each analog bistable feeds a safeguards logic relay in each safety injection channel.

With the exception of the high-high containment pressure relays, the logic relays are deenergized when an unsafe condition is detected.

During testing, a test switch in series with the logic matrix and the coil of the master relay prevents the master relay from being energized. Should a safeguards actuation be called for during testing, it will be initiated by either the other safeguards actuation logic network, or that portion of this safeguards actuation logic network which is not undergoing testing. Figure 1.5.2.2.3-6 presents a typical test circuit arrangement for a safeguards actuation logic matrix and master relay.

1.5.2.2.3.2.3 Support Systems. Successful operation of the SAS is dependent upon the electric power system--primarily the DC system. Each actuation channel receives DC power from a separate battery panel and battery. The primary sources of power for the safeguards actuation system are presented below. Test power supplies for this system are also included. DC power for each channel is monitored by two undervoltage relays which indicate on the front of the associated safeguards logic panel.

Subsystem	Power Source
Logic Channel 1 (panels 1-1 and 1-2)	Battery 21 through distribution panel 21
Logic Channel 2 (panels 2-1 and 2-2)	Battery 22 through distribution panel 22
Logic Channels 1 and 2 Testing	120 VAC instrument bus 22

1.5.2.2.3.2.4 Test and Surveillance Requirements. The various components in the SAS undergo periodic testing and surveillance. Maintenance is performed as required.

1. The process instrumentation channels are periodically tested to satisfy plant technical specifications as follows:

    a. Channel checks are performed at least twice per calendar day. A channel check is a qualitative determination of acceptable operability by observation of the instrument behavior during operation.

b. Channel functional tests are performed monthly. A channel functional test involves the injection of a simulated signal into the channel to verify operability, including alarm and/or trip initiating action.

c. Channel calibration for most instrumentation loops is performed during refueling outages. Channel calibration is the adjustment of channel output in such a manner that it responds, within acceptable range and accuracy, to known values of the parameters measured by the channel. Calibration encompasses the entire channel, including alarms or trips, and also includes the channel functional test.

2. The safeguards actuation logic channels are periodically tested to satisfy plant technical specification requirements as follows. Logic channel functional tests are performed monthly. A logic channel functional test is the application of input signals or the operation of relays or switch contacts in all the combinations required to produce the required decision output, including the operation of all actuation devices. However, for the safeguards actuation logic channels, the master relays are not energized. Instead, the coils for the relays are checked for continuity.

3. During refueling outages, a test safety injection signal is applied to check the operation of the engineered safety features. The safety injection and residual heat removal pumps are made inoperable for this test. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing; that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel.

4. The general test procedure and test sequence for the logic matrices are:

a. The safeguards initiation test panel is located on the front doors of the safeguards initiation relay panels and consists of three-position (left, right, and push) test switches, white indicating lamps, and a red test lamp. A typical test circuit is shown in Figure 1.5.2.2.3-6. The white light will be illuminated whenever the proper coincident relay contacts are closed. The lamp may be tested by depressing the lens.

b. In circuit 1 of Figure 1.5.2.2.3-6, a contact of the test switch is inserted in series with the logic matrix and the master relay. A second contact of the test switch is inserted in series with the analog bistable output and the logic relay, and a third contact is used to illuminate the test light. A test switch is provided for each logic relay.

c. When the test switch is in the left or normal position, contact 1a, in series with the master safeguards initiation relay, and contact 1b, in series with the logic relay, are closed. Contact 1c, in series with the red test light is opened.

d. With the test switch in the right position, contact 1a will be open, preventing the SI master relay from being energized by the particular function being tested. Contact 1c will be closed, illuminating the red test light. Contact 1b will be closed, maintaining the logic relay in an untripped condition.

e. With the test switch in the push position (either right or left): contact 1a will be open preventing the SI master relay from being energized by the particular function being tested; contact 1c will be closed, illuminating the test light; contact 1b will be opened, causing the logic relay to deenergize. With the proper number of logic relays deenergized or tripped, the white indicating light associated with that safeguards function will illuminate, indicating that the logic circuit is functioning properly. The test switches must be held in the pushed position, but the left and right positions are maintained.

f. The push positions of the test switch perform the same function. However, when testing is performed, it is essential that the switch be turned to the right prior to pushing. If this is not done, upon release of the switch, if the proper number of logic relays are deenergized, a circuit will be made up through contact 1a of the test switch to pick up the master relay.

g. Administrative testing procedures require that the test switches for the logic combinations being tested be first turned to the right and the red test lamp verified to be illuminated. The proper test switches will then be simultaneously pushed and the white test lamp for that particular function will be observed to determine if the logic relays are functioning properly. Each relay being tested will also illuminate its associated trip status light on panel SO and a common channel trip annunciator on the supervisory panel.

1.5.2.2.3.2.4 Operator Interaction. Operator action to manually initiate the SAS is excluded from this analysis. Operator errors during test or maintenance of this system are discussed in Section 1.5.2.2.3.4.6.

1.5.2.2.3.2.5 Common Cause Effect. The logic cabinets and instrumentation cabinets associated with this system are located in the control room behind the flight panels at Indian Point 2.

Common generic components of this system are supplied by the same manufacturers, are subject to common operation and test procedures, and have common susceptibility to secondary causes of failure, such as grit, moisture, and vibration.

Further discussion of the effects of common cause failure on system failure is presented in Section 1.5.2.2.3.4.5.

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1.5.2.2.3.3 Logic Model.

1.5.2.2.3.3.1 Event Tree. This system is input to the event trees developed for the LOCA, steam break, and loss of offsite power transients. Failure of this system is defined as failure to send an actuation signal to the actuated equipment. In the event tree, questions concerning the state of this system are asked following questions on electric power and before the actuated systems status.

1.5.2.2.3.3.2 System Fault Tree. Figure 1.5.2.2.3-7 presents the fault trees developed for the SAS. Discussion of the events and the quantification of the tree is presented in Section 1.5.2.2.3.4. Manual actuation of this system is always possible; however, this analysis does not include the probability of manual actuation.

The fault tree is developed for a LOCA condition in the plant. The fault tree logic for the steam line break and the loss of offsite power transients is similar.

1.5.2.2.3.3.3 Fault Tree Coding. Table 1.5.2.2.3-4 identifies the basic events, their failure modes, and the failure rates associated with these modes.

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1.5.2.2.3.4 Quantification.

1.5.2.2.3.4.1 Single Hardware Failures. No single hardware failures were identified in either the safety injection actuation or containment spray actuation systems.

1.5.2.2.3.4.2 Double Hardware Failures. The doubles contribution to system failure consist of random hardware failures in one logic channel coupled with random hardware failures in the other logic channel.

1.5.2.2.3.4.2.1 Safety injection actuation. Channel 1 of safety injection consists of the following basic components:

- Actuation Relay SIA-1
- Manual Actuation Relay SIM-1
- Reset Pushbutton PB/RS1
- Normal Defeat Switch A
- DC Power Fuses 2-1 through 6-1
- Equipment Actuation Relays 10X through 18X and 15AX
- Reset Relay SIR1
- DC Power from Distribution Panel 21

Failure of any equipment actuation relay is assumed to cause failure of the associated safety injection channel.

The time to detection for failures of the DC power fuses, the reset relay, and the normal defeat switch are based upon the following:

- DC power fuse. Indication of a failed fuse is available on the front of the affected safequards actuation panel. These panels are located in the control room and are under operator surveillance. Every shift (8 hours) the status of the panels is verified. The time to detection (4 hours) is based upon one-half of the interval between visual inspections.

- Normal defeat switch and reset relay. The failure mode of interest is the shorting across of normally open contacts. Failures of this type can only be detected during the monthly logic channel testing or upon a system demand. The time to detection assigned, 360 hours, and is based upon one-half of the interval between tests.

Channel 2 contains similar components.

The following equation defines the frequency of failure on demand for a single safety injection logic channel:

$$Q = 2(V1 + V4) + V2 + 10V3 + V5$$

where

V1 = probability of occurrence of a single short around open contacts.
V2 = probability of failure of a single master relay.

V3 = probability of failure of a single auxiliary relay.
V4 = probability of failure of a single fuse.
V5 = probability of reset pushbutton being depressed.
Q = channel unavailability on demand.

Using the failure data presented in Table 1.5.2.2.3-4 and the fault tree constructed for the event "No Safeguards Actuation Signal (SAS) from Channel 1," a distribution for the frequency of failure on demand characterized by the following mean and variance is obtained:

Mean: 3.64×10^{-4}

Variance: 1.02×10^{-6}

For the event "No Safeguards Actuation Signal" (LOCA), a distribution represented by the following mean and variance is obtained:

Mean: 1.19×10^{-6}

Variance: 2.34×10^{-11}

1.5.2.2.3.4.2.2 Containment spray actuation. Containment spray actuation channel 1 consists of the following components:

- Containment Spray Master Relay S1
- Containment Spray Reset Relay CS-1R
- Containment Spray Auxiliary Relay S1-1X
- DC Power Fuses 2-1 and 3-1
- Containment High-High Pressure Relay AS1
- Reset Pushbutton PB/RS-B1
- DC Power from Distribution Panel 21

The time to detection for failures of the DC power fuses and the reset relay are based upon the following:

- DC power fuse--4 hours based upon the discussion in Section 1.5.2.2.3.4.2.1.

- Reset relay--360 hours based upon the discussion in Section 1.5.2.2.3.4.2.1.

Channel 2 contains similar components.

The following equation defines the frequency of failure on demand for a single containment spray logic channel:

$$Q = V1 + V2 + 2(V3 + V4) + V5$$

where

V1 = probability of occurrence of a single short around open contacts.
V2 = probability of failure of a single master relay.
V3 = probability of failure of a single auxiliary relay.
V4 = probability of failure of a single fuse.
V5 = probability of reset pushbutton being depressed.
Q = channel unavailability on demand.

Using the failure data presented in Table 1.5.2.2.3-4 and the fault tree constructed for the event "No Spray Signal Generated Channel 1," a distribution for the frequency of failure on demand characterized by the following mean and variance is obtained:

Mean: 1.85×10^{-4}

Variance: 2.54×10^{-7}

For the event "No Containment Spray Actuation Signal," distribution characterized by the following mean and variance is obtained:

Mean: 2.99×10^{-7}

Variance: 1.46×10^{-12}

1.5.2.2.3.4.3 Instrument Loop Failures. Two groups of instruments are considered, those which initiate SI and those which initiate CS.

1.5.2.2.3.4.3.1 Instrument loop failures, SI. The instrument loops of interest for the LOCA transient are: pressurizer low pressure (three channels, two of three required); and containment high and high-high pressure (high two of three; high-high two of three, twice). A basic instrumentation loop consists of a sensor, transmitter, test device, test operate switches, bistable, power supply, and logic relays. In the instrumentation fault trees, the sensor and transmitter are grouped in the transmitter block, and the bistable and logic relays are grouped in the bistable block. Upon a loss of power to the instrument loop, the logic relays associated with the loop change state to close their logic matrix contacts. This is true for all SI instrumentation except high-high containment pressure. These relays must be energized to close the logic matrix contacts.

The time to detection for failures in the pressurizer and containment pressure transmitter networks are based upon the following:

- Pressurizer Pressure Transmitters. Although these transmitters are only calibrated during plant refueling outages, the output of these transmitters is under continuous observation during plant operation. Any deviation of a single channel will be detected during the

normal channel checks performed every shift. For this reason, 4 hours (one-half of the normal shift cycle) is defined as the mean detection time for failure of these transmitters.

- Containment Pressure Transmitters. These transmitters are also calibrated during refueling outages and routinely monitored in the control room; however, containment pressure does not vary significantly over the course of a single shift. Drift or other malfunctions in a single transmitter network will be detected during plant operation due to the normal pressure buildup that occurs inside the containment over one to several days. Based upon engineering judgment, the mean detection time for failure of the transmitter network is defined as 24 hours.

The following equation defines the frequency of failure on demand for the safety injection instrumentation:

$$Q = (9V3^2)(V1 + V2)^2$$

where

V1 = the probability of failure of a single pressurizer transmitter network.

V2 = the probability of failure of a single bistable/logic relay channel.

V3 = the probability of failure of a single containment pressure transmitter network.

Q = safety injection instrumentation unavailability on demand.

Based upon this equation, the following distribution for the failure of instrumentation to provide automatic trip signals to SIS is obtained:

Mean: 1.56×10^{-16}

Variance: 2.59×10^{-30}

1.5.2.2.3.4.3.2 Instrument loop failures, CS. The instrumentation which initiates containment spray consists of the containment high-high pressure transmitters and bistables. The six containment pressure transmitters are arranged in two groups of three with two of three high-high pressure signals required from each group for containment spray to be actuated. The instrumentation loops fail with no trip signal if power is lost to the instrument loop.

The mean detection time for failure of the high-high containment pressure transmitters is defined as 24 hours for the reasons noted in Section 1.5.2.2.3.4.3.1.

The following equation defines the frequency of failure on demand for the containment spray instrumentation.

$$Q = 6\ (V2 + V3)^2$$

where

V2 = the probability of failure of a single bistable/logic relay channel.

V3 = the probability of failure of a single containment pressure transmitter network.

Q = containment spray instrumentation unavailability on demand.

Based upon this equation, the frequency of failure for the containment high-high pressure signal is characterized by the following mean and variance:

Mean: 3.75×10^{-7}

Variance: 4.85×10^{-12}

1.5.2.2.3.4.4 System Failure Due to Test and Maintenance.

1.5.2.2.3.4.4.1 Testing. During system logic channel functional testing, open contacts operated by the test switch prevent the master SI relay from energizing. This testing is performed monthly and normally requires 4 to 6 hours for completion. The master SI relay is not blocked for the entire duration of the testing; however, in this analysis, it is assumed that the channel under test cannot perform its function for the entire duration of the test. The mean test duration is 5 hours with a variance of 1 hour. Using the test duration, and the data developed in Section 1.5.2.2.3.4.2.1 for a single SAS channel, the contribution to system failure for a single SAS channel under test and random failures in the other channel is:

Mean: $\frac{5 \text{ hours}}{\text{month}} \times \frac{1 \text{ month}}{720 \text{ hours}}\ 3.58 \times 10^{-4} = 2.53 \times 10^{-6}$

Variance: 4.97×10^{-11}

For the system total contribution to failure due to this testing, the contribution to failure while testing of the other logic channel must be added. This results in the following failure frequency for failure during test:

Mean: 5.05×10^{-6}

Variance: 1.99×10^{-10}

1.5.2.2.3.4.4.2 Maintenance. Maintenance of certain portions of this system is allowed by the plant technical specifications. Before performing instrumentation maintenance, the other channels of instrumentation which sense the same parameter are inspected to ensure their

operability. Upon completion of this inspection, the failed instrument is placed in the tripped position which, in effect, gives one part of the signal necessary for system actuation. Maintenance for these cases does not affect system availablity.

Maintenance is not performed on other portions of the SAS during plant operation.

1.5.2.2.3.4.5 Quantification of Common Cause. There is a potential for common instrument channel miscalibration errors to be applied to all instruments of a particular set. During the periodic calibrations, a single technician or group of technicians perform the tests necessary to ensure instrument accuracy. These tests are usually performed sequentially among identical channels. This leads to a close coupling between these acts. Most calibration activities, even if performed in error, do not result in an instrument that fails to provide a trip. In addition, the diversity in the types of instruments that provide trip signals limits the effect of these potential common cause miscalibrations. If the value of a single instrument channel failing (the sum of bistable, logic relays, and transmitter network failures) is used as the probability of common cause miscalibration of a set of instruments, failure of two sets of instrumentation due to miscalibration of this type would result in a mean and variance of:

Mean: 2.94×10^{-10}

Variance: 9.13×10^{-19}

This value is used as the frequency of common cause miscalibration of all instrumentation.

During the monthly logic channel testing, it can be seen from the fault tree that a single logic channel failure can cause failure of the SAS. Both trains of logic are tested sequentially which in principle could introduce some common cause coupling between the channels. However, the logic testing does not involve changing of trip set points or logic arrangements. For this reason, these testing failures are treated as independent events which do not affect system unavailability.

1.5.2.2.3.4.6 Quantification of Human Error. The human error of failing to actuate this system given an initiating event is outside of the boundary of this analysis; however, it is included in the plant event trees where appropriate.

Human errors during instrumentation calibration are discussed in Section 1.5.2.2.3.4.5.

During the monthly logic channel functional testing, there are potential candidates for human error quantification. These potential errors are discussed below:

1. Failure to Return "Normal-Defeat" Switch to "Normal" After Testing. This switch prevents the master relay from being energized. Failure to return this switch to normal defeats one entire channel

of safety injection/containment spray actuation. This switch is annunciated in the control room and this error, if made, is immediately detectable. Therefore, this potential human error is not quantified in this analysis.

2. Failure to Return Individual Test Switches to "Normal." These switches allow testing of the individual logic relays. All test switches are the push-turn type. All switches are annunciated at the individual safequards panel and each relay being tested is annunciated in the control room. Failure to return a switch to normal results in that particular channel of instrumentation being unable to provide a trip signal. Because these switches provide indication when they are in the test position, and because the individual channels are annunciated when testing, no human error quantification is performed for this condition.

1.5.2.2.3.4.7 System Quantification.

1.5.2.2.3.4.7.1 Safety injection actuation. Failure of the safety injection actuation subsystem is caused by failures in the individual logic channels, failures in the instrumentation, failure during test and maintenance, and common cause failures.

The frequency of safety injection actuation signal failure on demand is:

$$Q_{SI} = \alpha_{SI\ Logic}\ \alpha_{Instrumentation}\ \alpha_{TM}\ \alpha_{CC}$$

$$= 6.24 \times 10^{-6}$$

$$\beta^2_{SI} = 2.20 \times 10^{-10}$$

1.5.2.2.3.4.7.2 Containment spray actuation. Failure of the containment spray actuation subsystem is caused by: failures in the individual logic channels, failures in the instrumentation, failures during test and maintenance, and common cause failures.

The frequency of containment spray actuation signal failure on demand is:

$$Q_{CS} = \alpha_{CS\ Logic}\ \alpha_{Instrumentation}\ \alpha_{TM}\ \alpha_{CC} = 5.66 \times 10^{-6}$$

$$\beta^2_{CS} = 1.49 \times 10^{-10}$$

TABLE 1.5.2.2.3-1

INDIAN POINT 2 SUMMARY OF RESULTS SAFEGUARDS ACTUATION SYSTEM

System	Mean	Variance	5th Percentile	95th Percentile	Median	WASH-1400 (median values)
A. Safety Injection Actuation						
1. Logic Channels	1.2×10^{-6}	2.3×10^{-11}	1.8×10^{-8}	4.6×10^{-6}	2.8×10^{-7}	9.0×10^{-6}
2. Instrumentation	1.6×10^{-16}	2.6×10^{-30}	4.3×10^{-19}	5.3×10^{-16}	1.5×10^{-17}	-
3. Test and Maintenance	5.0×10^{-6}	2.0×10^{-10}	1.5×10^{-7}	1.9×10^{-5}	1.7×10^{-6}	1.3×10^{-5}
4. Common Cause	2.9×10^{-10}	9.1×10^{-19}	6.6×10^{-12}	1.1×10^{-9}	8.7×10^{-11}	4.5×10^{-5}
5. System Failure on Demand	6.2×10^{-6}	2.2×10^{-10}	2.3×10^{-7}	2.5×10^{-5}	2.4×10^{-6}	9.9×10^{-5}
B. Containment Spray Actuation						
1. Logic Channels	3.0×10^{-7}	1.5×10^{-12}	4.5×10^{-9}	1.2×10^{-6}	7.2×10^{-8}	6.5×10^{-5}
2. Instrumentation	3.8×10^{-7}	4.9×10^{-12}	2.8×10^{-4}	1.4×10^{-6}	6.3×10^{-8}	-
3. Test and Maintenance	5.0×10^{-6}	2.0×10^{-10}	1.5×10^{-7}	1.9×10^{-5}	1.7×10^{-6}	2.0×10^{-5}
4. Common Cause	2.9×10^{-10}	9.1×10^{-19}	6.6×10^{-12}	1.1×10^{-9}	8.7×10^{-11}	1.0×10^{-3}
5. System Failure on Demand	5.7×10^{-6}	1.5×10^{-10}	2.7×10^{-7}	2.1×10^{-5}	2.4×10^{-6}	1.1×10^{-3}

TABLE 1.5.2.2.3-2

INDIAN POINT 2 SAFEGUARDS ACTUATION SYSTEM SIGNALS AND LOGIC

Parameter	Logic Arrangement	Setpoint	Actuates	Remarks
1. SAFETY INJECTION ACTUATION				
a. Manual Safety Injection	Two pushbuttons	N/A	Equivalent to auto SI except: containment isolation phase A (CIA) not actuated; and ventilation isolation actuated.	One pushbutton only starts minimum required equipment. Both must be depressed to ensure all equipment receives a start signal.
b. High Steam Line Flow in Conjunction with Low T_{avg} or Low Steam Line Pressure	Two out of four high steam flow (one out of two signals for two out of four loops) in conjunction with:	Programmed based on turbine first stage pressure:		Two flow transmitters per steam line. One of two high generates high flow signal. Two of four signals required.
	• Two out of four low T_{avg}	• 540°F	• Auto SI*	• Any two of four
	• Two out of four low steam line pressure	• 600 psig	• Steam Line Isolation	• Any two of four
c. Steam Line Differential Pressure	One out of four channels of two out of three pressure comparison networks.	150 psid	Auto SI*	
d. Low Pressurizer Pressure	Two out of three channels of pressurizer pressure.	1,700 psig	Auto SI*	Blocked by operator action during shutdown.
e. High Containment Pressure	Two out of three channels of containment pressure.	2.0 psig	Auto SI*	
2. CONTAINMENT SPRAY ACTUATION				
a. Manual Spray	Two pushbuttons	N/A	Spray Actuation; Containment Isolation Phase B (CIB); Containment Ventilation Isolation	One pushbutton only starts minimum required equipment. Both must be depressed to ensure all equipment receives a start signal.

*Auto SI includes: feedwater isolation; reactor trip; safeguards sequence including auxiliary feedwater, safety injection, fan cooling, service water; containment isolation phase A; CCR ventilation isolation.

TABLE 1.5.2.2.3-2 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION SYSTEM SIGNALS AND LOGIC

Parameter	Logic Arrangement	Setpoint	Actuates	Remarks
b. High-High Containment Pressure	Two sets of two out of three pressure signals (two out of three twice).	30 psig	Spray Actuation; CIB; Containment Ventilation Isolation; Steam Line Isolation (through high steam flow relay)	The only automatic safeguards actuation signal which requires power at the trip bistable to trip (i.e., energized to trip).
3. MISCELLANEOUS SAFEGUARDS CIRCUITS				
a. Manual Steam Line Isolation	One pushbutton per loop (four loops).	N/A	None	Closes MSIVs only.
b. Manual Containment Isolation - Phase A	Two pushbuttons.	N/A	CIA; Isolation Valve Seal Water; Containment Ventilation Isolation	
c. Manual Containment Isolation - Phase B	Two pushbuttons.	N/A	CIB	
d. High Containment Activity	One of two (air particulate or radiogas).	R-11: 2.0×10^{-7} μ ci/cc R-12: 2.4×10^{-5} μ ci/cc	Containment Ventilation Isolation	
e. Safety Injection Manual Reset	Manual pushbuttons and timer.	N/A	Resets Automatic Safety Injection Logic	Locked out by timer for 2 minutes.
f. Containment Isolation Phase A Reset	N/A	N/A	N/A	Resets signal.
g. Spray Actuation Reset	N/A	N/A	N/A	Resets signal.
h. Containment Isolation Phase B Reset	N/A	N/A	N/A	Resets signal.

TABLE 1.5.2.2.3-3

INDIAN POINT 2 SAFEGUARDS ACTUATION RELAYS/ACTUATED EQUIPMENT

Logic Channel and Relay	Device Actuated	Equipment Actuated	Remarks
Logic Channel 1			
1. SI Automatic Actuation Relay SIA-1	a. C-A1		a. Containment Isolation Phase A
	b. 2SID1		b. Safeguards Sequencing
	c. SI-10X		c. Equipment Actuation Relay
	d. SI-11X		d. Equipment Actuation Relay
	e. SI-12X		e. Equipment Actuation Relay
	f. SI-13X		f. Equipment Actuation Relay
	g. SI-14X		g. Equipment Actuation Relay
	h. SI-15X		h. Equipment Actuation Relay
2. SI Manual Actuation Relay SIM-1	a. V1		a. Vent Isolation Relay
	b. 2SID1		b. Safeguards Sequencing
	c. SI-10X		c. Equipment Actuation Relay
	d. SI-11X		d. Equipment Actuation Relay
	e. SI-12X		e. Equipment Actuation Relay
	f. SI-13X		f. Equipment Actuation Relay
	g. SI-14X		g. Equipment Actuation Relay
	h. SI-15X		h. Equipment Actuation Relay
3. Equipment Actuation Relay SI-10X	a. F1X		a. Feedwater Isolation Relay
	b. F2X		b. Feedwater Isolation Relay
	c. F3X		c. Feedwater Isolation Relay
	d. F4X		d. Feedwater Isolation Relay
		e. 42/CCBP21	e. Auxiliary CC Booster Pump 21
		f. Valve 851B	f. High Head SIS Pump 22 Stop Valve
		g. Valve 746	g. RHR Loop Discharge Stop Valve
		h. Valve 822A	h. CCW Outlet from RHR Hx
		i. Valve 856A	i. High Head Branch Line Stop Valve - Cold leg
		j. Valve 856C	j. High Head Branch Line Stop Valve - Cold leg
		k. Valve 894A	k. Accumulator Discharge Stop Valve (DO)
		l. Valve 894C	l. Accumulator Discharge Stop Valve (DO)
4. Equipment Actuation Relay SI-11X	a. SI-16X		a. Equipment Actuation Relay
	b. SI-17X		b. Equipment Actuation Relay
	c. SI-18X		c. Equipment Actuation Relay
		d. Valve 1821	d. BIT Discharge Valve
		e. Valve 1822A	e. BIT Discharge Valve
		f. 52/2AT3A	f. Bus 2A-3A Tie Breaker
5. Equipment Actuation Relay SI-12X		a. Reactor Trip	
		b. Diesel Start (3)	b. 21, 23 Primary Auto Start; 22 Backup Auto Start
6. Equipment Actuation Relay SI-13X		a. 52/AF1	a. Auxiliary Feedwater Pump 21
		b. 52/AF3	b. Auxiliary Feedwater Pump 23
		c. BFPB Relay	c. Block NonSI Blackout Logic (Train B)
		d. Reactor Trip	
		e. BFPB3 Relay	e. Block NonSI Blackout Logic (Train A)
7. Equipment Actuation Relay SI-14X		a. Diesel Generator 21 Lockout circuit	
		b. Diesel Generator 22 Lockout circuit	
		c. Diesel Generator 23 Lockout circuit	
	d. SI-16X		d. Equipment Actuation Relay
	e. SI-17X		e. Equipment Actuation Relay
	f. SI-18X		f. Equipment Actuation Relay

TABLE 1.5.2.2.3-3 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION RELAYS/ACTUATED EQUIPMENT

Logic Channel and Relay	Device Actuated	Equipment Actuated	Remarks
8. Equipment Actuation Relay SI-15X	a. SI-15AX	b. SI Pump 21 c. Valve 888A d. Valve 746	a. Auxiliary Relay (SI Pumps) c. High Head Recirculation Stop Valve d. RHR Loop Discharge Stop Valve
9. Equipment Actuation Relay SI-15AX		a. SI Pump 22 b. SI Pump 22	
10. Equipment Actuation Relay SI-16X		a. Containment Air Recirculation Flow Control Valves b. Containment Air Recirculation Flow Alarms	b. Common RCF Filter Flow Path - Low Flow Alarm
11. Equipment Actuation Relay SI-17X		a. 2/CCWF b. Valve SOV-1170 c. Valve SOV-1276	a. Containment Cooling Water Low SW Flow Alarm b. SW Containment Cooling Water c. SW D/G Cooling Water
12. Equipment Actuation Relay SI-18X		a. Central Control Room Ventilation Fans and Damper Controls	
13. Steam Line Isolation Relay SL1	a. SIA-1 b. MS1 c. MS2 d. MS3 e. MS4		a. SI Actuation Relay b. MSIV 21 c. MSIV 22 d. MSIV 23 e. MSIV 24
14. High Containment Pressure AS1	a. SL1 b. S1		a. Steam Line Isolation Relay b. Containment Spray Relay
15. Containment Spray Relay S1	a. C-B1 b. V1 c. S1-1X		a. Containment Isolation Phase B Relay b. Vent Isolation Relay c. CS Auxiliary Relay
16. Containment Spray Auxiliary Relay S1-1X		a. 52/CS1 b. Valve 876A c. Valve 866A d. Valve 866C	a. Containment Spray Pump 21 b. Additive Tank Outlet Valve c. CS Pump 21 Discharge Valve d. CS Pump 22 Discharge Valve
17. Containment Isolation Phase B Relay C-B1	a. C-B-11X		a. Containment Isolation Phase B Auxiliary Relay
18. Containment Phase B Auxiliary Relay C-B-11X		a. Valve 222 b. Valve PCV-1229 c. Valve 797 d. Valve 784 e. Valve FCV-625	a. RCS Pump Seal Return b. SJAE to Containment c. CC to RCS Pumps d. CC From RCP Motor Bearings e. CC From RCP Thermal Barrier
19. Containment Ventilation Isolation Relay V1		a. Containment Purge Valves b. Containment Pressure Relief Valves	a. To/From (all valves) b. To/From (all valves)

TABLE 1.5.2.2.3-3 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION RELAYS/ACTUATED EQUIPMENT

Logic Channel and Relay	Device Actuated	Equipment Actuated	Remarks
20. Containment Isolation Phase A Relay C-A1	a. C-A11X b. C-A12X c. C-A13X d. C-A14X e. V1		a. Phase A Equipment Actuation Relay b. Phase A Equipment Actuation Relay c. Phase A Equipment Actuation Relay d. Phase A Equipment Actuation Relay e. Vent Isolation Relay
21. Phase A Equipment Actuation Relay C-A11X		a. Valve 200A b. Valve 200B c. Valve 200C d. Valve 201 e. Valves 1V-1A,2A,3A,5A, SOV-3420, 3421 f. Valve 519 g. Valve 548 h. Valve 791 i. Valve 793	a. Letdown Flow control, 75 GPM Orifice b. Letdown Flow Control, 45 GPM Orifice c. Letdown Flow Control, 75 GPM Orifice d. Letdown From Regenerative Hx e. H_2 Recombiner System Isolation Valves f. Makeup to Pressurizer Relief Tank g. Gas Analyzer - Pressurizer Relief Tank h. CC to Excess Letdown Hx i. CC From Excess Letdown Hx
22. Phase A Equipment Actuation Relay C-A12X		a. PCV-1229 b. Valve 956A c. Valve 956C d. Valve 956E e. Valves 1V-1A,2A,3A,5A, SOV-3420,3421 f. Valve 1410 (open) g. Valve 956G h. Valve 1702 i. Valve 1723	a. SJAE to Containment b. Sample - Pressurizer Steam c. Sample - Pressurizer Liquid d. Sample - RCS e. H_2 Recombiner System Isolation Valves f. IVSW Isolation Valve (opens) g. Accumulator Sample h. RC Drain Tank to WDS Holdup Tank i. Containment Sump Pumps to WDS Holdup Tank
23. Phase A Equipment Actuation Relay C-A13X		a. Valve 1786 b. Valve 1788 c. S/G Blowdown and Sample Isolation Valves d. SOV 1534 (C), 1538 (O), 1536 (C), 1540 (O) e. PCV-1228	a. Vent Header From RC Drain Tank b. Gas Analyzer - RC Drain Tank c. (17 valves) d. Containment RAD Monitor Solenoid Valve e. Instrument Air Valve to Containment
24. Phase A Equipment Actuation Relay C-A14X		a. Personnel Lock Valves b. Equipment Hatch Lock Valves c. SOV 3429 (interlock) d. SOV 3425 (interlock) e. MOV 956E (close) f. MOV 4399 (close) g. MOV 990A (close) h. MOV 5153 (close) i. Valve 956J	a. SOVs b. SOVs
25. Feedwater Isolation Relay F1X	a. F5X	b. Valve FCV-417	a. Auxiliary Feedwater Isolation Relay b. Feedwater Level Control Valve S/G 21

TABLE 1.5.2.2.3-3 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION RELAYS/ACTUATED EQUIPMENT

Logic Channel and Relay	Device Actuated	Equipment Actuated	Remarks
26. Feedwater Isolation Relay F2X	a. F5X		a. Auxiliary Feedwater Isolation Relay
		b. Valve FCV-427	b. Feedwater Level Control Valve S/G 22
27. Feedwater Isolation Relay F3X	a. F5X		a. Auxiliary Feedwater Isolation Relay
		b. Valve FCV-437	b. Feedwater Level Control Valve S/G 23
28. Feedwater Isolation Relay F4X	a. F5X		a. Auxiliary Feedwater Isolation Relay
		b. Valve FCV-447	b. Feedwater Level Control Valve S/G 24
29. Auxiliary Feedwater Isolation Relay F5X		a. 86P Relay	a. Generator Primary Lockout Relay
		b. BFPD1	b. Boiler Feed Pump 21 Discharge Valve
		c. BFPD2	c. Boiler Feed Pump 22 Discharge Valve
Logic Channel 2			
1. SI Automatic Actuation Relay SIA-2	a. C-A2		a. Containment Isolation Phase A
	b. 2SID2		b. Safeguards Sequencing
	c. SI-20X		c. Equipment Actuation Relay
	d. SI-21X		d. Equipment Actuation Relay
	e. SI-22X		e. Equipment Actuation Relay
	f. SI-23X		f. Equipment Actuation Relay
	g. SI-24X		g. Equipment Actuation Relay
	h. SI-25X		h. Equipment Actuation Relay
2. SI Manual Actuation SIM-2	a. V2		a. Vent Isolation Relay
	b. 2SID2		b. Safeguards Sequencing
	c. SI-20X		c. Equipment Actuation Relay
	d. SI-21X		d. Equipment Actuation Relay
	e. SI-22X		e. Equipment Actuation Relay
	f. SI-23X		f. Equipment Actuation Relay
	g. SI-24X		g. Equipment Actuation Relay
	h. SI-25X		h. Equipment Actuation Relay
3. Equipment Actuation Relay SI-20X	a. F11X		a. Feedwater Isolation Relay
	b. F12X		b. Feedwater Isolation Relay
	c. F13X		c. Feedwater Isolation Relay
	d. F14X		d. Feedwater Isolation Relay
		e. 42/CCBP22	e. Auxiliary CC Booster Pump 22
		f. Valve 851A	f. High Head SIS Pump 22 Stop Valve
		g. Valve 747	g. RHR Loop Discharge Stop Valve
		h. Valve 822B	h. CCW Outlet From RHR Hx
		i. Valve 856E	i. High Head Branch Line Stop Valve - Cold Leg
		j. Valve 856D	j. High Head Branch Line Stop Valve - Cold Leg
		k. Valve 894B	k. Accumulator Discharge Stop Valve (DO)
		l. Valve 894D	l. Accumulator Discharge Stop Valve (DO)
4. Equipment Actuation Relay SI-21X	a. SI-26X		a. Equipment Actuation Relay
	b. SI-27X		b. Equipment Actuation Relay
	c. SI-28X		c. Equipment Actuation Relay
		d. Valve 1831	d. BIT Discharge Valve
		e. Valve 1822B	e. BIT Discharge Valve
		f. 52/2AT3A	f. Bus 2A-3A Tie Breaker

TABLE 1.5.2.2.3-3 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION RELAYS/ACTUATED EQUIPMENT

Logic Channel and Relay	Device Actuated	Equipment Actuated	Remarks
5. Equipment Actuation Relay SI-22X		a. Reactor Trip b. Diesel Start (3)	b. 21, 23 Backup Auto Start, 22 Primary Auto Start
6. Equipment Actuation Relay SI-23X		a. 52/AF1 b. 52/AF3 c. BFPB Relay d. Reactor Trip e. BFPB3 Relay	a. Auxiliary Feedwater Pump 21 b. Auxiliary Feedwater Pump 23 c. Block NonSI Blackout Logic (Train B) e. Block NonSI Blackout Logic (Train A)
7. Equipment Actuation Relay SI-24X	d. SI-26X e. SI-27X f. SI-28X	a. Diesel Generator 21 Lockout Circuit b. Diesel Generator 22 Lockout Circuit c. Diesel Generator 23 Lockout Circuit	d. Equipment Actuation Relay e. Equipment Actuation Relay f. Equipment Actuation Relay
8. Equipment Actuation Relay SI-25X	a. SI-25AX	b. RHR Pump 21 c. RHR Pump 22 d. SI Pump 23 e. Valve 888B f. Valve 747	a. Auxiliary Relay (SI Pumps) e. High Head Recirculation Stop Valve f. RHR Loop Discharge Stop Valve
9. Equipment Actuation Relay SI-25AX		a. SI Pump 22 b. SI Pump 22	
10. Equipment Actuation Relay SI-26X		a. Containment Air Recirculation Flow Control Valves b. Containment Air Recirculation Flow Alarms	b. Common RCF Filter Flow Path - Low Flow Alarm
11. Equipment Actuation Relay SI-27X		a. 2/CCWF b. Valve SOV-1171 c. SOV-1276A	a. Containment Cooling Water Low SW Flow Alarm b. SW Containment Cooling Water c. SW D/G Cooling Water
12. Equipment Actuation Relay SI-28X		a. Central Control Room Ventilation Fans and Damper Controls	
13. Steam Line Isolation Relay SL2	a. SIA-2 b. MS11 c. MI12 d. MS13 e. MS14		a. SI Actuation Relay b. MSIV 21 c. MSIV 22 d. MSIV 23 e. MSIV 24
14. High Containment Pressure Relay AS2	a. SL2 b. S2		a. Steam Line Isolation Relay b. Containment Spray Relay
15. Containment Spray Relay S2	a. C-B2 b. V2 c. S2-1X		a. Containment Isolation Phase B Relay b. Vent Isolation Relay c. CS Auxiliary Relay

TABLE 1.5.2.2.3-3 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION RELAYS/ACTUATED EQUIPMENT

Logic Channel and Relay	Device Actuated	Equipment Actuated	Remarks
16. Containment Spray Auxiliary Relay S2-1X		a. 52/CS2 b. Valve 876B c. Valve 866B d. Valve 866D	a. Containment Spray Pump 22 b. Additive Tank Outlet Valve c. CS Pump 21 Discharge Valve d. CS Pump 22 Discharge Valve
17. Containment Isolation Phase B Relay C-B2	a. C-B-21X		a. Containment Isolation Phase B Auxiliary Relay
18. Containment Isolation Phase B Auxiliary Relay C-B-21X		a. Valve 222 b. Valve PCV-1230 c. Valve 769 d. Valve 786 e. Valve 789	a. RCP Pump Seal Return b. SJAE to Containment c. CC to RCS Pumps d. CC From RCP Motor Bearings e. CC From RCP Thermal Barrier
19. Containment Ventilation Isolation Relay V2		a. Containment Purge Valves b. Containment Pressure Relief Valves	a. To/From (all valves) b. To/From (all valves)
20. Containment Isolation Phase A Relay C-A2	a. C-A21X b. C-A22X c. C-A23X d. C-A24X e. V2		a. Phase A Equipment Actuation Relay b. Phase A Equipment Actuation Relay c. Phase A Equipment Actuation Relay d. Phase A Equipment Actuation Relay e. Vent Isolation Relay
21. Phase A Equipment Actuation Relay C-A21X		a. Valve 202 b. Valves 1V-1B,2B,3B,5B, SOV-3422,3423 c. Valve 552 d. Valve 549 e. Valve 796 f. Valve 798	a. Letdown From Regenerative Hx b. H_2 Recombiner System Isolation Valves c. Makeup to Pressurizer Relief Tank d. Gas Analyzer - Pressurizer Relief Tank e. CC From Excess Letdown Hx f. CC to Excess Letdown Hx
22. Phase A Equipment Actuation Relay C-A22X		a. PCV-1230 b. Valve 956B c. Valve 956D d. Valve 956F e. Valves 1V-1B,2B,3B,5B; SOV-3422,3423 f. Valve 1413 (open) g. Valve 956H h. Valve 1705 i. Valve 1728	a. SJAE to Containment b. Sample - Pressurizer Sample c. Sample - Pressurizer Liquid d. Sample - RCS e. H_2 Recombiner System Isolation Valves f. IVSW Isolation Valve (opens) g. Accumulator Sample h. RC Drain Tank to WDS Holdup Tank i. Containment Sump Pumps to WDS Holdup Tank
23. Phase A Equipment Actuation Relay C-A23X		a. Valve 1787 b. Valve 1789 c. S/G Blowdown and Sample Isolation Valves d. SOV 1537 (C), 1541 (O), 1535 (C), 1539 (O) e. PCV-1228	a. Vent Header from RC Drain Tank b. Gas Analyzer RC Drain Tank c. (17 valves) d. Containment RAD Monitor Solenoid Valve e. Instrument Air Valve to Containment

TABLE 1.5.2.2.3-3 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION RELAYS/ACTUATED EQUIPMENT

Logic Channel and Relay	Device Actuated	Equipment Actuated	Remarks
24. Phase A Equipment Actuation Relay C-A24X		a. Personnel Lock Valves b. Equipment Hatch Lock Valve c. MOV-5132 (close) d. MOV-5154 (close) e. MOV-990B (close) f. MOV-956F (close) g. Valve 956K	a. SOVs b. SOVs
25. Feedwater Isolation Relay F11X	a. F15X	b. Valve FCV-417	a. Auxiliary Feedwater Isolation Relay b. Feedwater Level Control Valve S/G 21
26. Feedwater Isolation Relay F12X	a. F15X	b. Valve FCV-427	a. Auxiliary Feedwater Isolation Relay b. Feedwater Level Control Valve S/G 22
27. Feedwater Isolation Relay F13X	a. F15X	b. Valve FCV-437	a. Auxiliary Feedwater Isolation Relay b. Feedwater Level Control Valve S/G 23
28. Feedwater Isolation Relay F14X	a. F15X	b. Valve FCV-447	a. Auxiliary Feedwater Isolation Relay b. Feedwater Level Control Valve S/G 24
29. Auxiliary Feedwater Isolation Relay F15X		a. 86BU Relay b. BFPD1 c. BFPD2	a. Generator Backup Lockout Relay b. Boiler Feed Pump 21 Discharge Valve c. Boiler Feed Pump 22 Discharge Valve

TABLE 1.5.2.2.3-4

INDIAN POINT 2 SAFEGUARDS ACTUATION SYSTEM BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data					Comments
		Mean	H/D*	Variance	MTTR	Reference**	
1. No Output from DC Bus 21	4BS--21D	N/A	-	-	-	-	
2. No Output from DC Bus 22	4BS--22D	N/A	-	-	-	-	
3. No Output from AC Instrument Inverter 1/Q948	J4Q948D	N/A	-	-	-	-	
4. No Output from AC Instrument Bus 22	JBSAC22D	N/A	-	-	-	-	
5. No Output from AC Instrument Bus 24	JBSAC24D	N/A	-	-	-	-	
6. No Operator Initiation of Safety Injection	MNOOPACT	1.0	-	0	-	-	Quantified in text
7. Safeguards Relay, SIA1, Fails to Close	MRESIA1S	1.15×10^{-5}	D	3.38×10^{-9}	-	47	
8. Safeguards Relay, SIA2, Fails to Close	MRESIA2S	1.15×10^{-5}	D	3.38×10^{-9}	-	47	
9. SI Manual Relay, SIM1, Fails to Close	MRESIM1S	1.15×10^{-5}	D	3.38×10^{-9}	-	47	
10. SI Manual Relay, SIM2, Fails to Close	MRESIM2S	1.15×10^{-5}	D	3.38×10^{-9}	-	47	
11. Short Across Reset Push Button, PB/RS-1	MPBRS1-F	4.28×10^{-7}	H	3.36×10^{-10}	360 hours	51	
12. Short Across Reset Push Button, PB/RS-2	MPBRS2-F	4.28×10^{-7}	H	3.36×10^{-10}	360 hours	51	
13. Short Across Normal Defeat Switch 1	MSWNODF1	4.28×10^{-7}	H	3.36×10^{-10}	360 hours	51	
14. Short Across Normal Defeat Switch 2	MSWNODF2	4.28×10^{-7}	H	3.36×10^{-10}	360 hours	51	
15. DC Fuse 2-1, Opens Prematurely	MFU02-1K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
16. DC Fuse 3-1, Opens Prematurely	MFU03-1K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
17. DC Fuse 2-2, Opens Prematurely	MFU02-2K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
18. DC Fuse 3-2, Opens Prematurely	MFU03-2K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
19. DC Fuse 4-1, Opens Prematurely	MFU04-1K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
20. DC Fuse 4-2, Opens Prematurely	MFU04-2K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
21. DC Fuse 5-1, Opens Prematurely	MFU05-1K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
22. DC Fuse 5-2, Opens Prematurely	MFU05-2K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
23. DC Fuse 6-1, Opens Prematurely	MFU06-1K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
24. DC Fuse 6-2, Opens Prematurely	MFU06-2K	8.32×10^{-7}	H	1.08×10^{-9}	1 hour	46	
25. Equipment Actuation Relay, 10x, Fails to Close	MRE10X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
26. Equipment Actuation Relay, 20x, Fails to Close	MRE20X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
27. Equipment Actuation Relay, 11x, Fails to Close	MRE11X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
28. Equipment Actuation Relay, 21x, Fails to Close	MRE21X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
29. Equipment Actuation Relay, 12x, Fails to Close	MRE12X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
30. Equipment Actuation Relay, 22x, Fails to Close	MRE22X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
31. Equipment Actuation Relay, 13x, Fails to Close	MRE13X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
32. Equipment Actuation Relay, 23x, Fails to Close	MRE23X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
33. Equipment Actuation Relay, 14x, Fails to Close	MRE14X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
34. Equipment Actuation Relay, 24x, Fails to Close	MRE24X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
35. Equipment Actuation Relay, 15x, Fails to Close	MRE15X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
36. Equipment Actuation Relay, 25x, Fails to Close	MRE25X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
37. Equipment Actuation Relay, 16X, Fails to Close	MRE16X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
38. Equipment Actuation Relay, 26X, Fails to Close	MRE26X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
39. Equipment Actuation Relay, 17X, Fails to Close	MRE17X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	

*H = Hours; D = Demand
**Reference refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.2.3-4 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION SYSTEM BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data					Comments
		Mean	H/D*	Variance	MTTR	Reference**	
40. Equipment Actuation Relay, 27X, Fails to Close	MRE27X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
41. Equipment Actuation Relay, 18X, Fails to Close	MRE18X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
42. Equipment Actuation Relay, 28X, Fails to Close	MRE28X-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
43. Equipment Actuation Relay, 15AX, Fails to Close	MRE15AX-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
44. Equipment Actuation Relay, 25AX, Fails to Close	MRE25AX-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
45. Steam Line Isolation Relay SL1, Fails to Close	MRESL1-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
46. Steam Line Isolation Relay SL2, Fails to Close	MRESL2-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
47. Containment Spray Relay, AS1, Fails to Close	MREAS1-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
48. Containment Spray Relay, AS2, Fails to Close	MREAS2-S	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
49. Pressurizer Pressure Transmitter Network 455, Fails to Provide a Trip Signal	MPT455-S	1.66×10^{-6}	H	6.28×10^{-12}	4 hours	50	
50. Pressurizer Pressure Transmitter Network 456, Fails to Provide a Trip Signal	MPT456-S	1.66×10^{-6}	H	6.28×10^{-12}	4 hours	50	
51. Pressurizer Pressure Transmitter Network 457, Fails to Provide a Trip Signal	MPT457-S	1.66×10^{-6}	H	6.28×10^{-12}	4 hours	50	
52. Pressurizer Pressure Transmitter Network 948A, Fails to Provide a Trip Signal	MPT948AS	1.66×10^{-6}	H	6.28×10^{-12}	84 hours	50	
53. Containment Pressure Transmitter Network 948B, Fails to Provide a Trip Signal	MPT948BS	1.66×10^{-6}	H	6.28×10^{-12}	84 hours	50	
54. Containment Pressure Transmitter Network 948C, Fails to Provide a Trip Signal	MPT948CS	1.66×10^{-6}	H	6.28×10^{-12}	84 hours	50	
55. No Trip Signal from Pressurizer Low Pressure Network, 455D:	MPC455ES	6.67×10^{-6}	D	2.50×10^{-11}	-		Made up of logic relay and bistable
• Logic relay	-	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable	-	3.88×10^{-7}	D	1.47×10^{-13}	-	49	
56. No Trip Signal from Pressurizer Low Pressure Network, 456D:	MPC456ES	6.67×10^{-6}	D	2.50×10^{-11}	-		Made up of logic relay and bistable
• Logic relay	-	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable	-	3.88×10^{-7}	D	1.47×10^{-13}	-	49	
57. No Trip Signal from Pressurizer Low Pressure Network, 457D:	MPC457ES	6.67×10^{-6}	D	2.50×10^{-11}	-		Made up of logic relay and bistable
• Logic relay	-	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable	-	3.88×10^{-7}	D	1.47×10^{-13}	-	49	

*H = Hours; D = Demand
**Reference refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.2.3-4 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION SYSTEM BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data					Comments
		Mean	H/D*	Variance	MTTR	Reference**	
58. No Trip Signal from Containment High Pressure Network, 948D:	MPC948DS	6.67×10^{-6}	D	2.50×10^{-11}	-		Made up of logic relay and bistable
• Logic relay	-	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable	-	3.88×10^{-7}	D	1.47×10^{-13}	-	49	
59. No Trip Signal from Containment High Pressure Network, 948E:	MPC948ES	6.67×10^{-6}	D	2.50×10^{-11}	-		Made up of logic relay and bistable
• Logic relay	-	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable	-	3.88×10^{-7}	D	1.47×10^{-13}	-	49	
60. No Trip Signal from Containment High Pressure Network, 948F:	MPC948FS	6.67×10^{-6}	D	2.50×10^{-11}	-		Made up of logic relay and bistable
• Logic relay	-	6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable	-	3.88×10^{-7}	D	1.47×10^{-13}	-	49	
61. No Operator Initiation of Containment Spray 1	MMANCSS1	1.0	-	0	-	-	Quantified in text
62. No Operator Initiation of Containment Spray 2	MMANCSS2	1.0	-	0	-	-	Quantified in text
63. Containment Spray Relay, S1-0, Fails to Close	MRES1--S	1.15×10^{-5}	D	3.38×10^{-9}	-	47	
64. Containment Spray Relay, S2-0, Fails to Close	MRES2--S	1.15×10^{-5}	D	3.38×10^{-9}	-	47	
65. Containment Spray Auxiliary Relay, S11X, Fails to Close	MRES11XS	6.28×10^{-6}	D	2.49×10^{-4}	-	41	
66. Containment Spray Auxiliary Relay, S21X, Fails to Close	MRES21XS	6.28×10^{-6}	D	2.49×10^{-4}	-	41	
67. Short Across Containment Spray Reset Relay, S1-R	MRECS1RE	4.28×10^{-7}	H	3.36×10^{-10}	360 hours	51	
68. Short Across Containment Spray Reset Relay, S2-R	MRECS2RE	4.28×10^{-7}	H	3.36×10^{-10}	360 hours	51	
69. Containment Presure Transmitter Network 949A, Fails to Provide a Trip Signal	MPT949AS	1.66×10^{-6}	H	6.28×10^{-12}	84 hours	50	
70. Containment Presure Transmitter Network 949B, Fails to Provide a Trip Signal	MPT949BS	1.66×10^{-6}	H	6.28×10^{-12}	84 hours	50	
71. Containment Presure Transmitter Network 949C, Fails to Provide a Trip Signal	MPT949CS	1.66×10^{-6}	H	6.28×10^{-12}	84 hours	50	
72. No Trip Signal from Containment High-High Pressure Network, 948A:	MPC948AS	6.67×10^{-6}	D	2.50×10^{-11}	-	-	Made up of logic relay and bistable
• Logic relay		6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable		3.88×10^{-7}	D	1.47×10^{-13}	-	49	
73. No Trip Signal from Containment High-High Pressure Network, 948B:	MPC948BS	6.67×10^{-6}	D	2.50×10^{-11}	-	-	Made up of logic relay and bistable
• Logic relay		6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable		3.88×10^{-7}	D	1.47×10^{-13}	-	49	
74. No Trip Signal from Containment High-High Pressure Network, 948C:	MPC948CS	6.67×10^{-6}	D	2.50×10^{-11}	-	-	Made up of logic relay and bistable
• Logic relay		6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable		3.88×10^{-7}	D	1.47×10^{-13}	-	49	

*H = Hours; D = Demand
**Reference refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.2.3-4 (continued)

INDIAN POINT 2 SAFEGUARDS ACTUATION SYSTEM BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data					Comments
		Mean	H/D*	Variance	MTTR	Reference**	
75. No Trip Signal from Containment High-High Pressure Network, 949A:	MPC949AS	6.67×10^{-6}	D	2.50×10^{-11}	-	-	Made up of logic relay and bistable
• Logic relay		6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable		3.88×10^{-7}	D	1.47×10^{-13}	-	49	
76. No Trip Signal from Containment High-High Pressure Network, 949B:	MPC949BS	6.67×10^{-6}	D	2.50×10^{-11}	-	-	Made up of logic relay and bistable
• Logic relay		6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable		3.88×10^{-7}	D	1.47×10^{-13}	-	49	
77. No Trip Signal from Containment High-High Pressure Network, 949C:	MPC949CS	6.67×10^{-6}	D	2.50×10^{-11}	-	-	Made up of logic relay and bistable
• Logic relay		6.28×10^{-6}	D	2.49×10^{-11}	-	41	
• Bistable		3.88×10^{-7}	D	1.47×10^{-13}	-	49	

*H = Hours; D = Demand
**Reference refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.2.3-5

INDIAN POINT 2 RESULTS TABLE - SAFEGUARDS ACTUATION SYSTEM

Event Description	Mean	Variance	Effect on System	Mean	Variance
A. SAFETY INJECTION ACTUATION					
1. SI Channel Logic	3.64×10^{-4}	1.02×10^{-6}	Loss of a single channel, no effect on system.	—	—
2. SI Logic--Two Channels	1.19×10^{-6}	2.34×10^{-11}	System failure.	1.19×10^{-6}	2.34×10^{-11}
3. Instrumentation Failure	1.56×10^{-16}	2.59×10^{-30}	No signal to SI - system failure.	1.56×10^{-16}	2.59×10^{-30}
4. Test and Maintenance and Random Failures	5.05×10^{-6}	1.99×10^{-10}	System failure.	5.05×10^{-6}	1.99×10^{-10}
5. Common Cause Miscalibration of Sensors	2.94×10^{-10}	9.13×10^{-19}	No signal to SI - system failure.	2.94×10^{-10}	9.13×10^{-19}
6. System Failure on Demand (SI)	-	-	N/A	6.24×10^{-6}	2.20×10^{-10}
B. CONTAINMENT SPRAY ACTUATION					
1. CS Channel Logic	1.85×10^{-4}	2.54×10^{-7}	Loss of single channel; loss of one-half CS pumps.	-	-
2. CS Logic--Two Channels	2.99×10^{-7}	1.46×10^{-12}	System failure.	2.99×10^{-7}	1.46×10^{-12}
3. Instrumentation Failure	3.75×10^{-7}	4.85×10^{-12}	No signal to CS - system failure.	3.75×10^{-7}	4.85×10^{-12}
4. Test and Maintenance and Random Failures	5.05×10^{-6}	1.99×10^{-10}	System Failure.	5.05×10^{-6}	1.99×10^{-10}
5. Common Cause Miscalculation of Sensors	2.94×10^{-10}	9.13×10^{-19}	No signal to CS - system failure.	2.94×10^{-10}	9.13×10^{-19}
6. System Failure on Demand (CS)	-	-	N/A	5.66×10^{-6}	1.49×10^{-10}

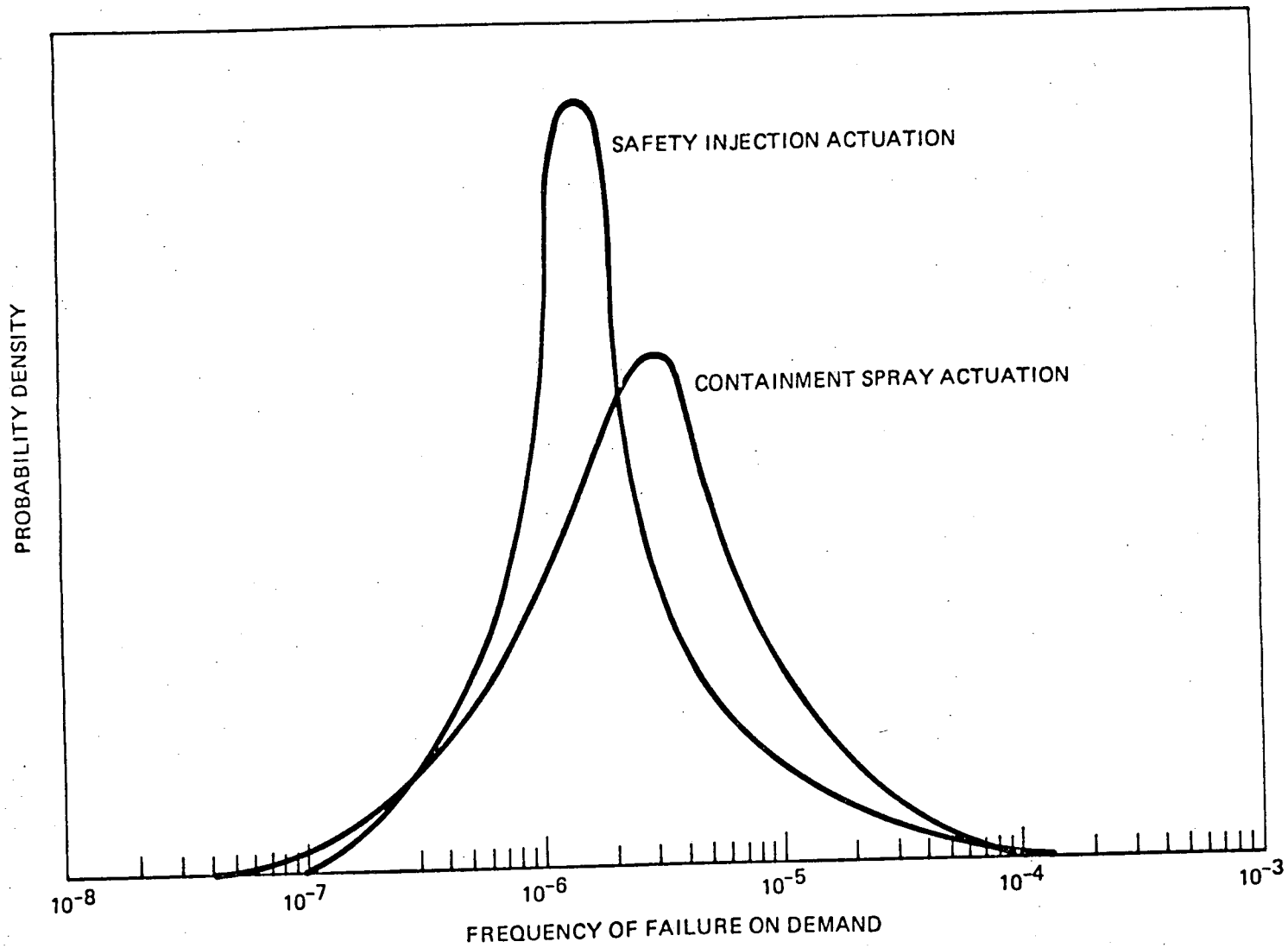


Figure 1.5.2.2.3-1. Probability Distribution of Indian Point 2 Safeguards Actuation System Failure on Demand

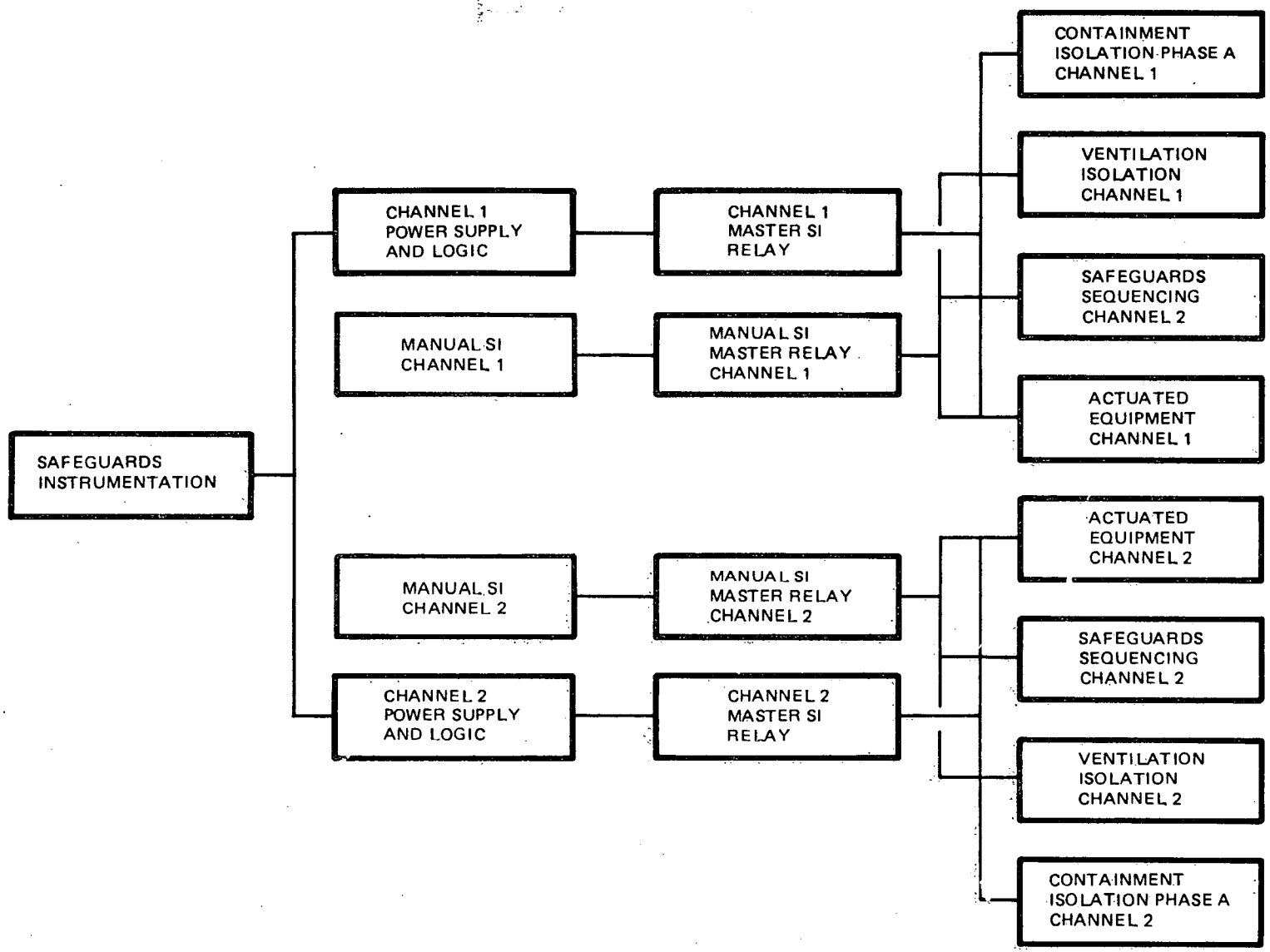


Figure 1.5.2.2.3-2. Indian Point 2 Safeguards Actuation System
Safety Injection Subsystem

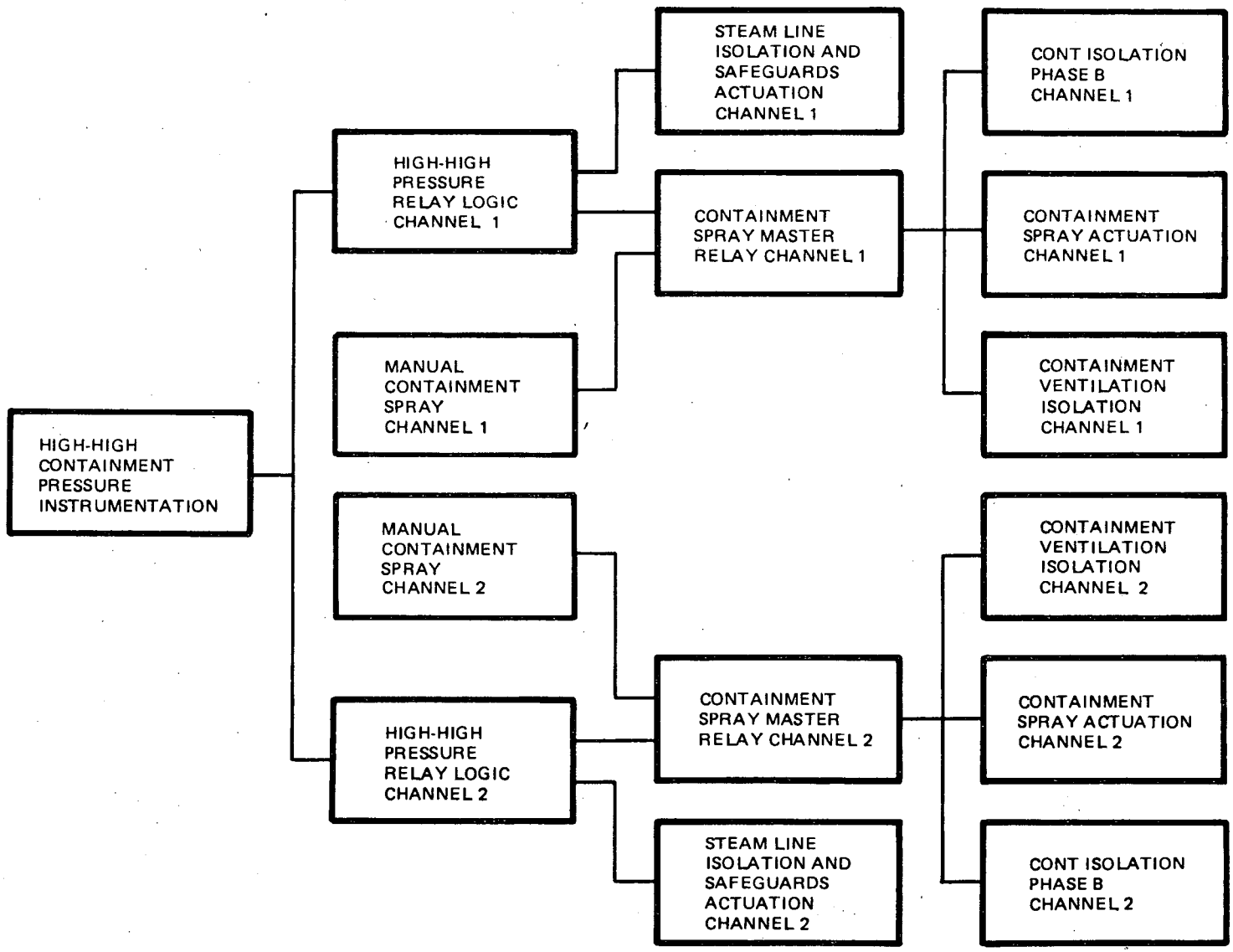


Figure 1.5.2.2.3-3. Indian Point 2 Safeguards Actuation System Containment Spray Subsystem

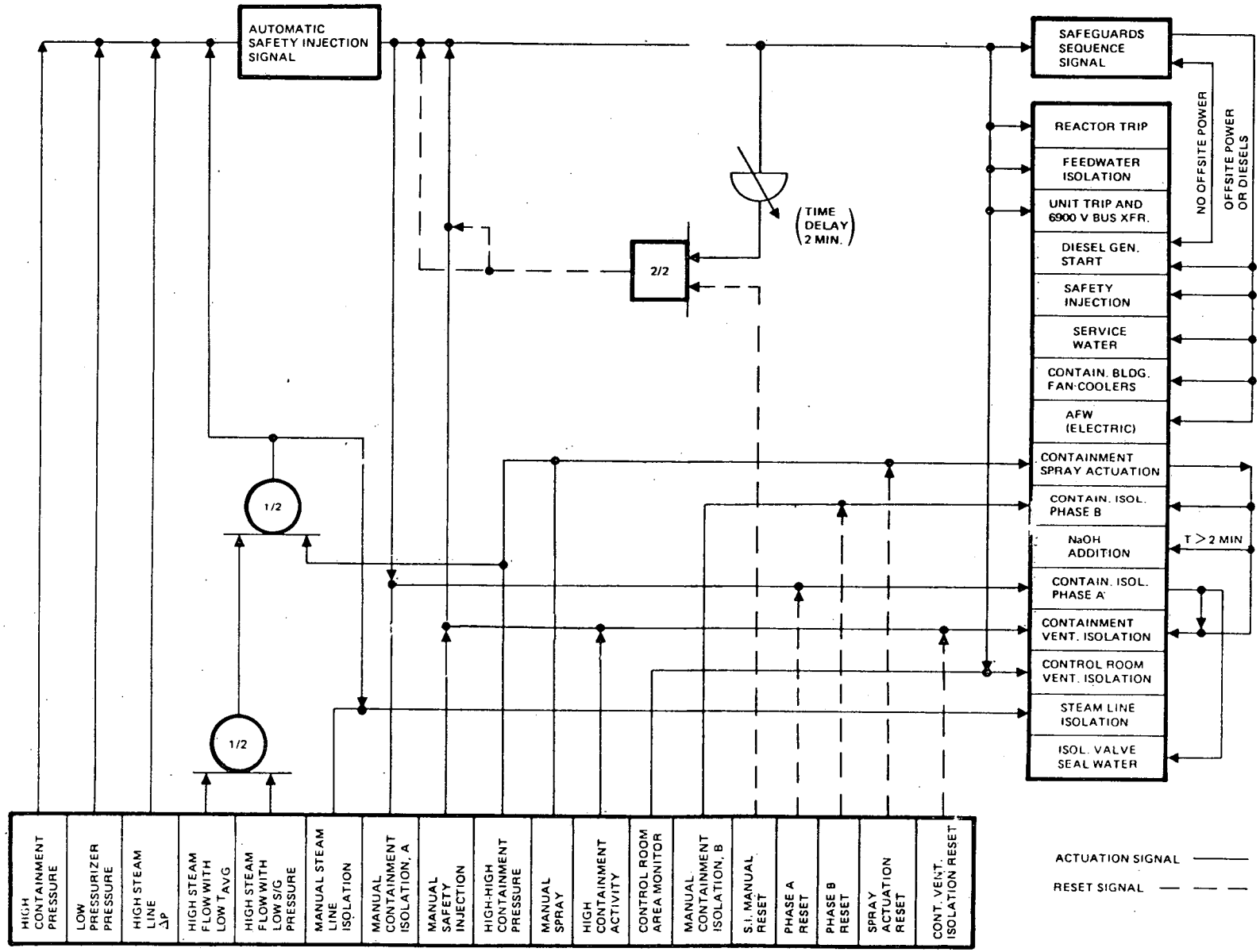


Figure 1.5.2.2.3-4. Indian Point 2 Safeguards Actuation System Functional Block Diagram Relationships

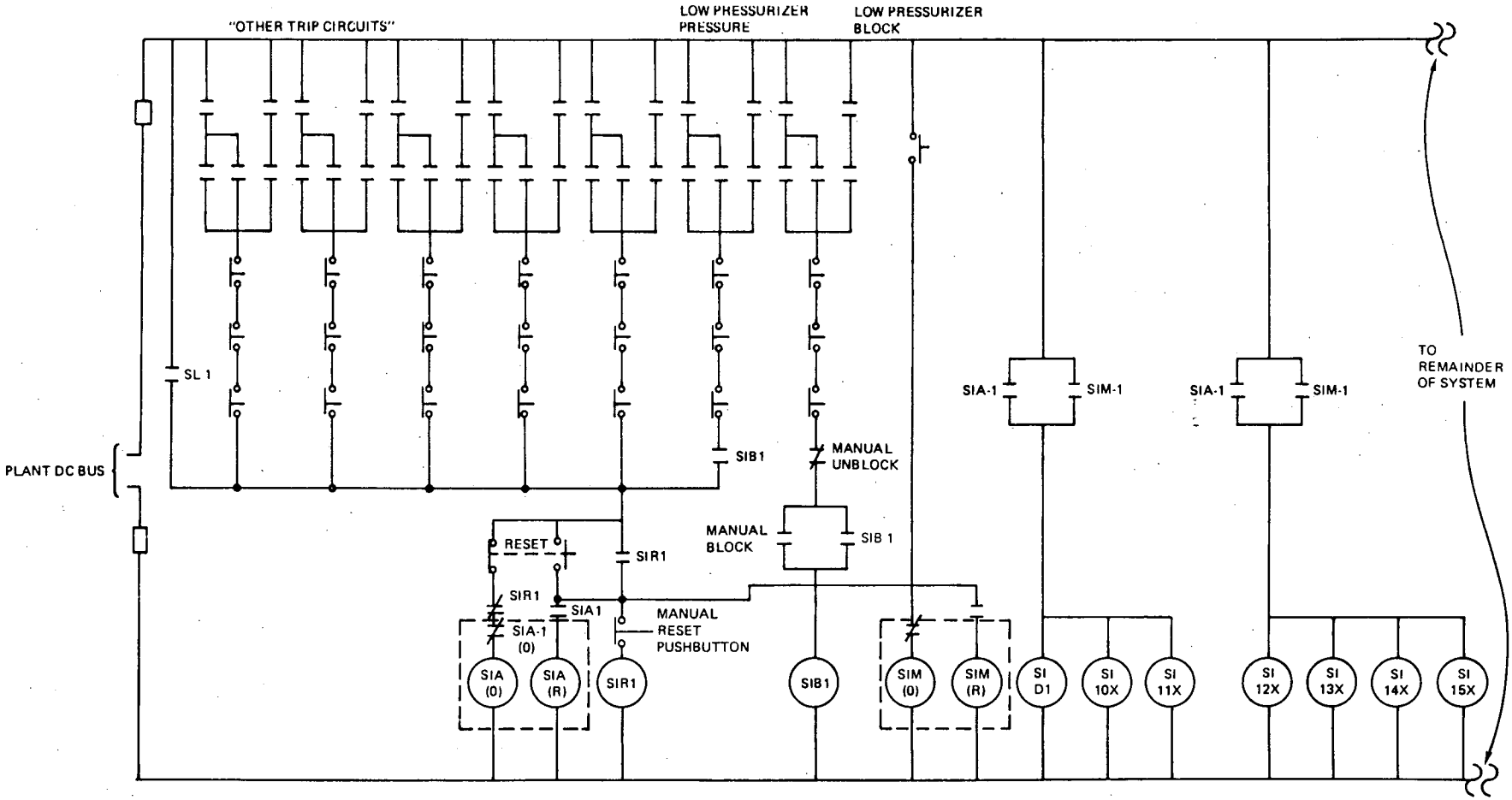


Figure 1.5.2.2.3-5. Indian Point 2 Safeguards Logic Matrix

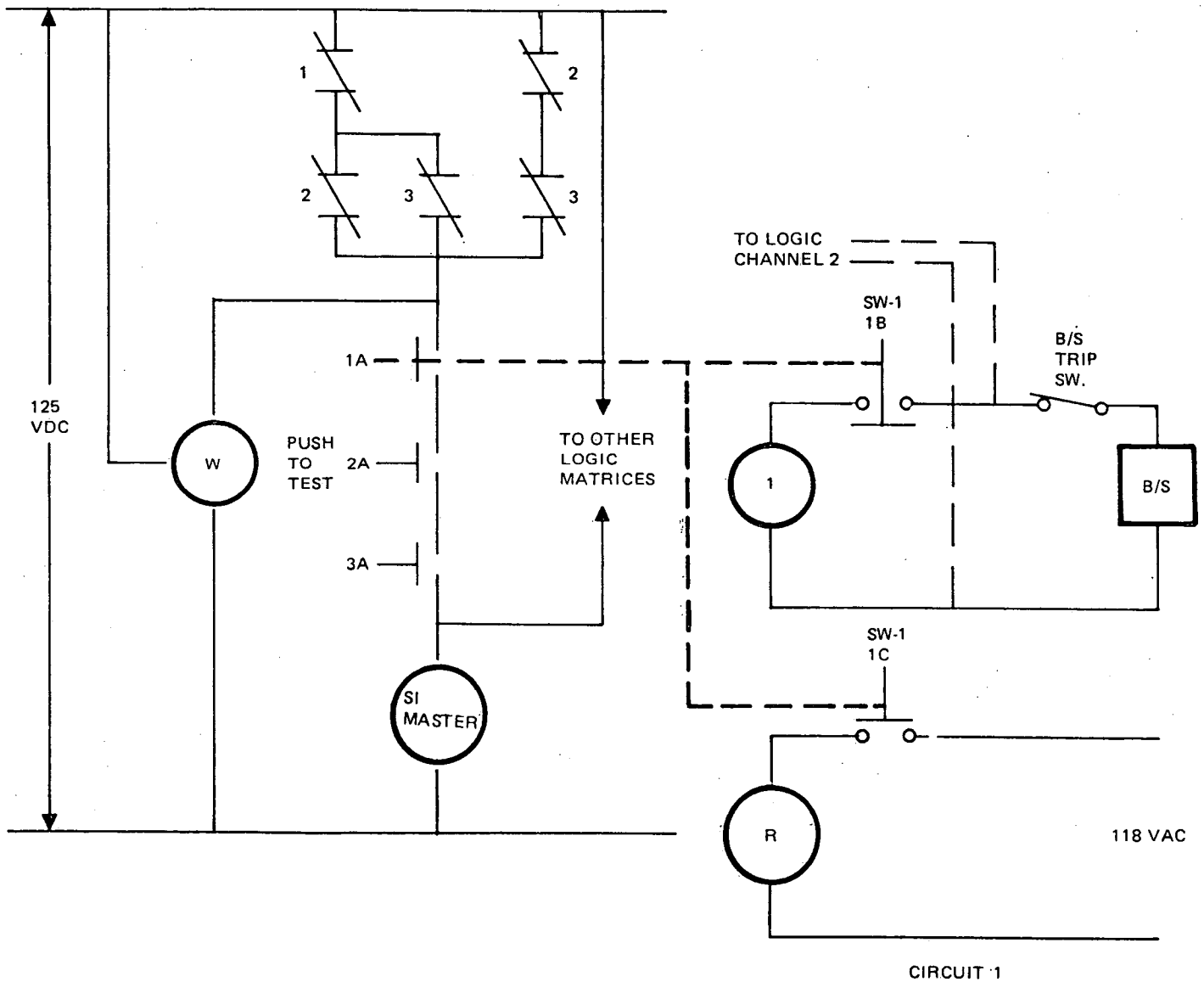
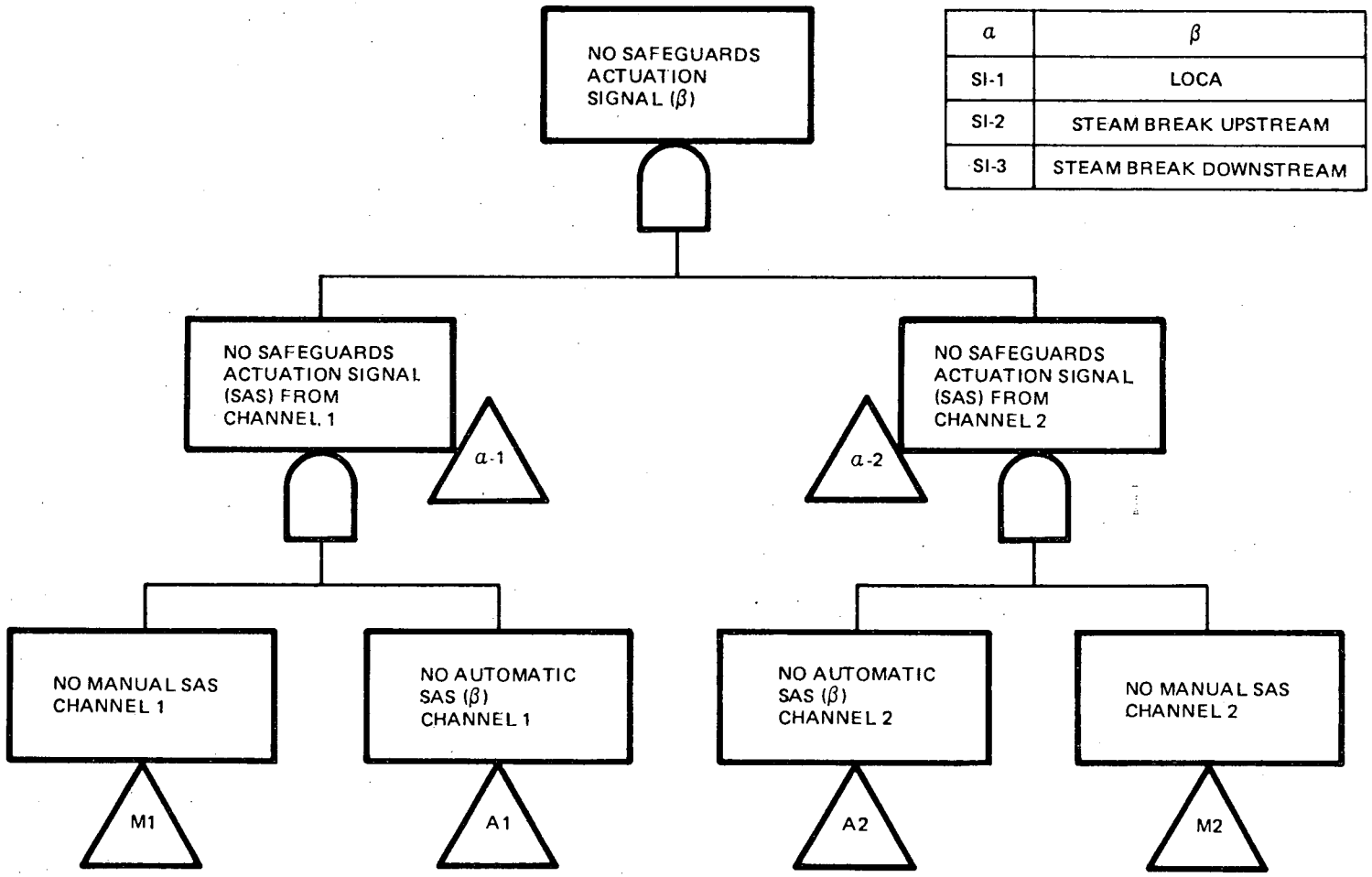


Figure 1.5.2.2.3-6. Indian Point 2 Safeguards Actuation System Test Schematic



α	β
SI-1	LOCA
SI-2	STEAM BREAK UPSTREAM
SI-3	STEAM BREAK DOWNSTREAM

Figure 1.5.2.2.3-7. Indian Point 2 Safeguards Actuation System Fault Tree (Sheet 1 of 23)

γ	β	a	δ
1	LOA	LOCA	AIP
2	LOB	LOCA	BIP
1	SBA	STEAM BREAK UPSTREAM	AIP
2	SBB	STEAM BREAK UPSTREAM	BIP
1	SDA	STEAM BREAK DOWNSTREAM	AIP
2	SDB	STEAM BREAK DOWNSTREAM	BIP

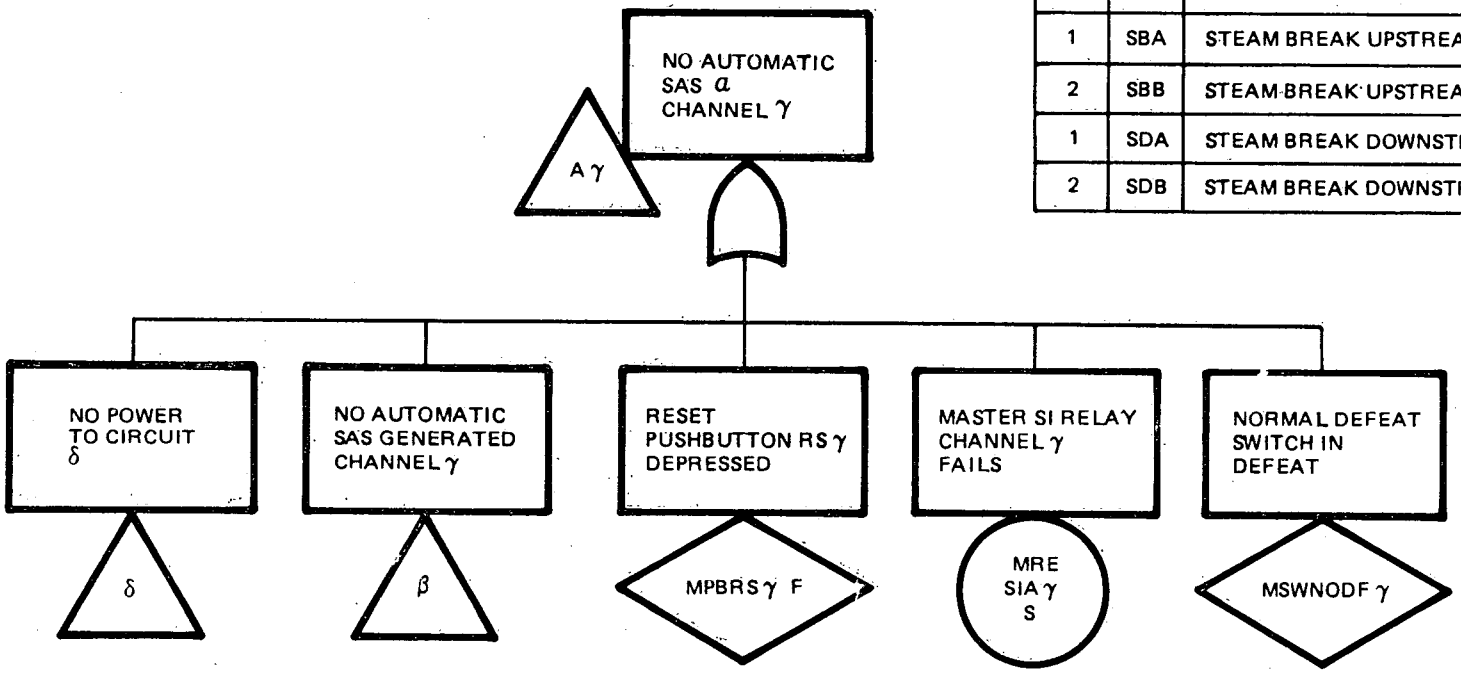


Figure 1.5.2.2.3-7. (Sheet 2 of 23)

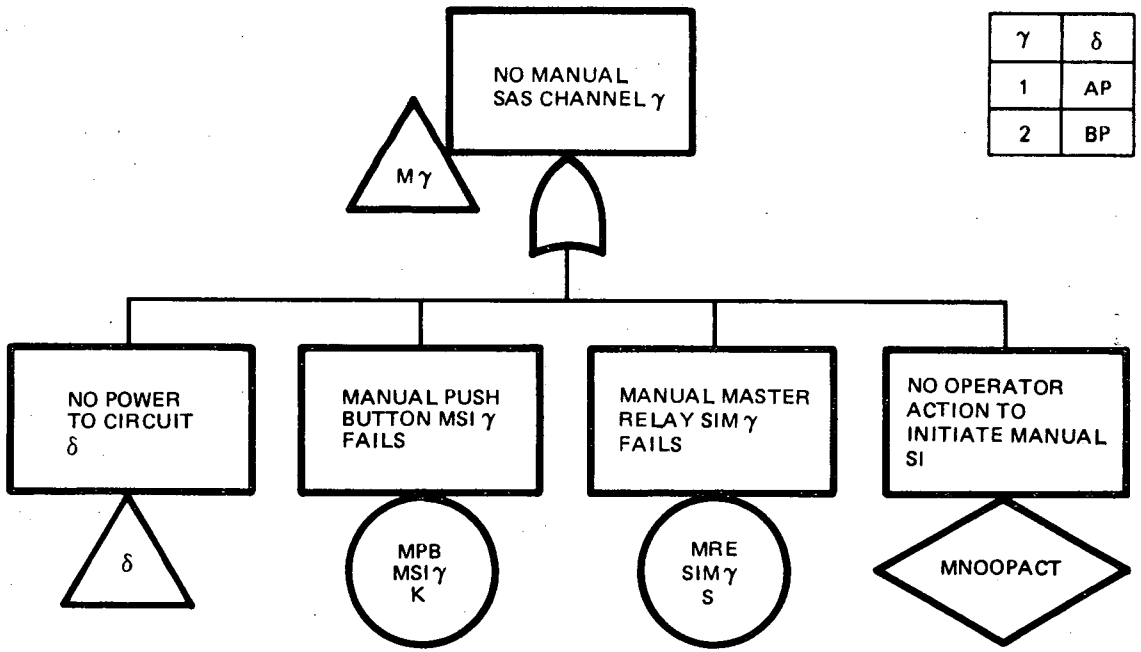


Figure 1.5.2.2.3-7. (Sheet 3 of 23)

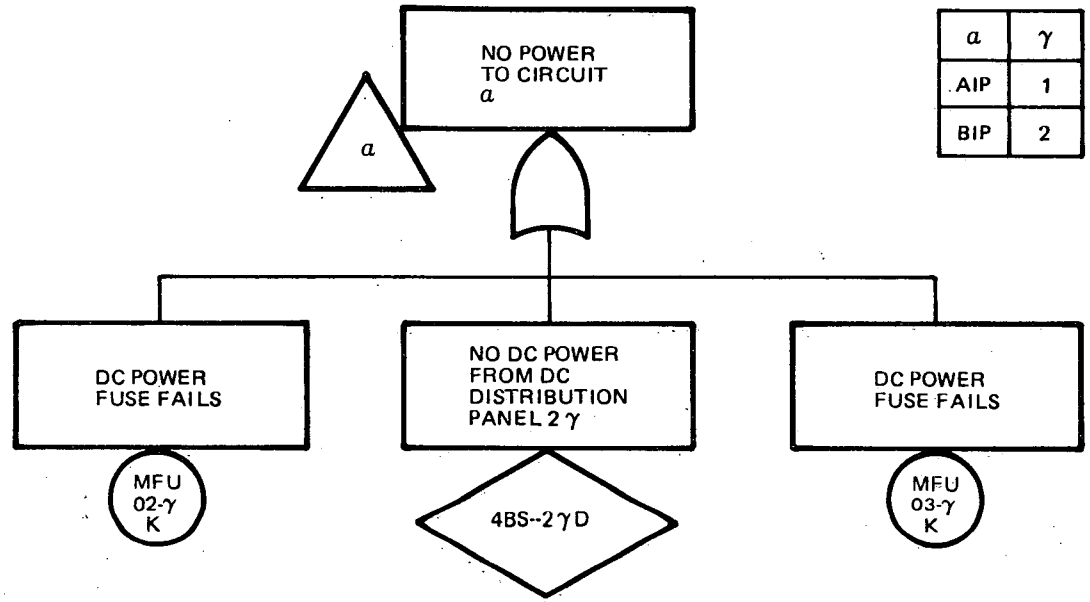
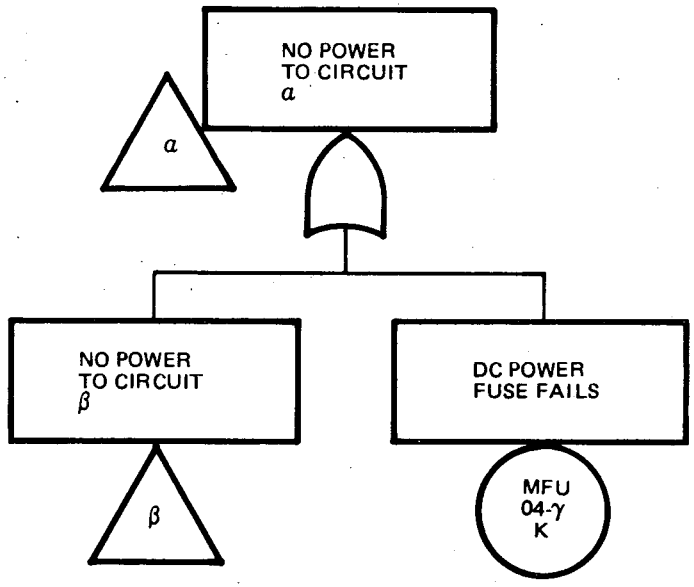


Figure 1.5.2.2.3-7. (Sheet 4 of 23)



α	β	γ
AP	AIP	1
BP	BIP	2

Figure 1.5.2.2.3-7. (Sheet 5 of 23)

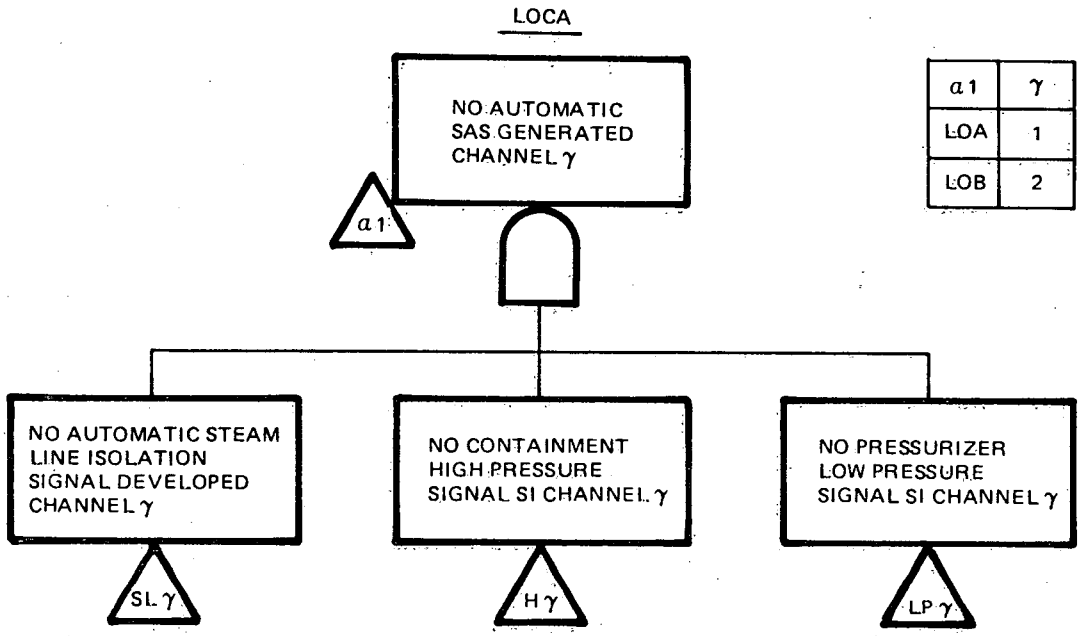


Figure 1.5.2.2.3-7. (Sheet 6 of 23)

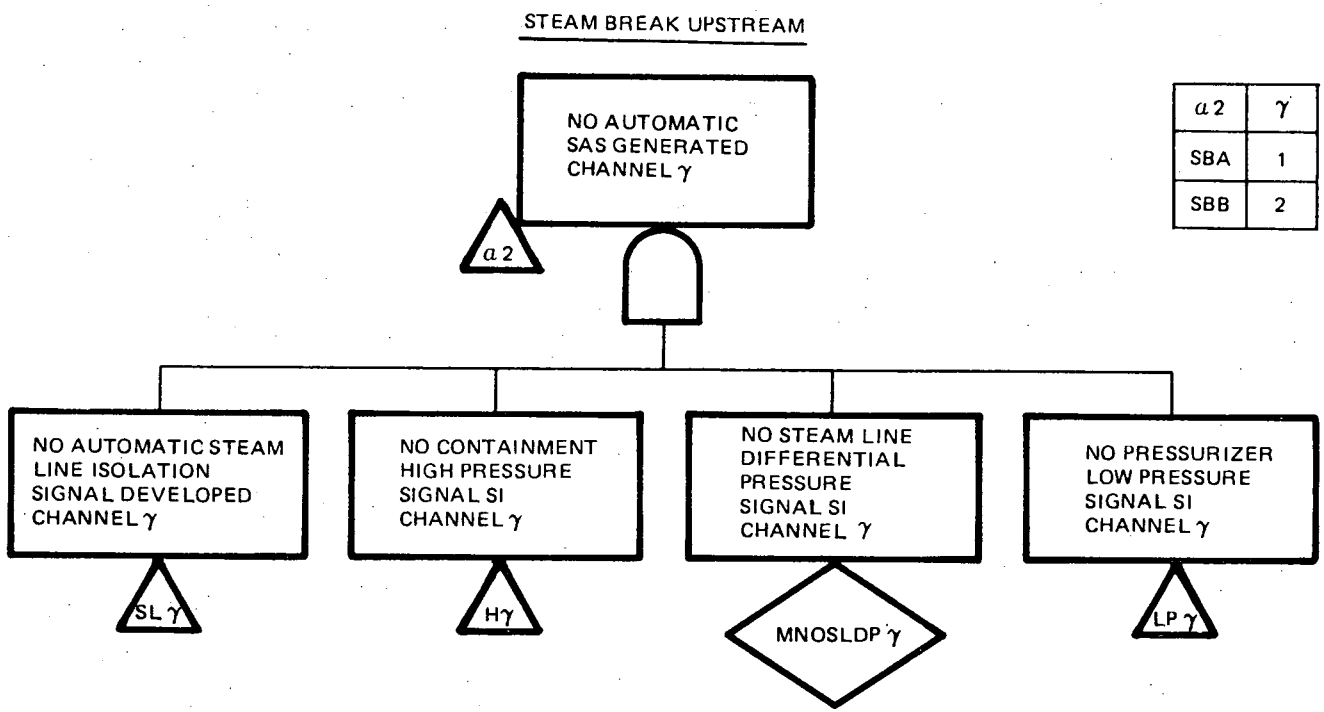


Figure 1.5.2.2.3-7. (Sheet 7 of 23)

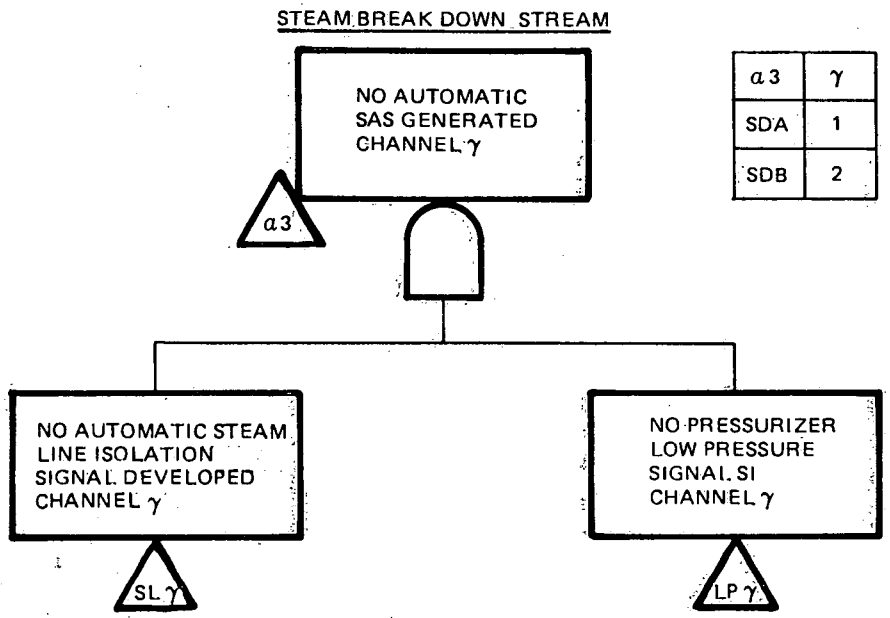
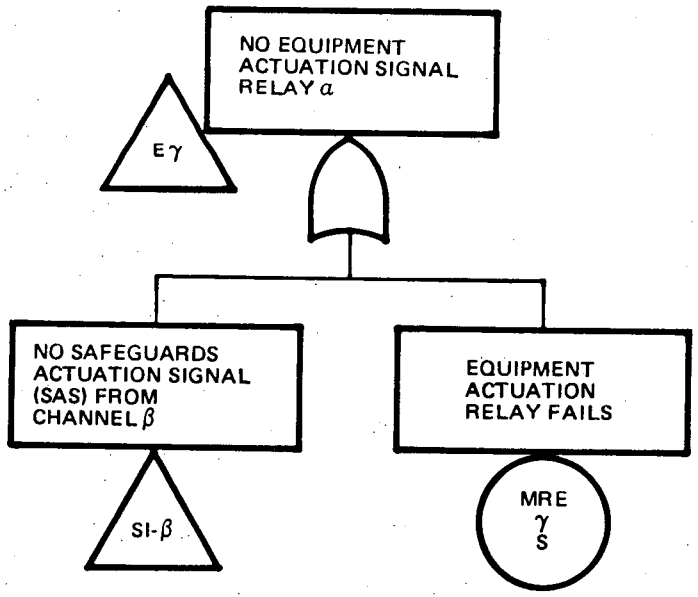
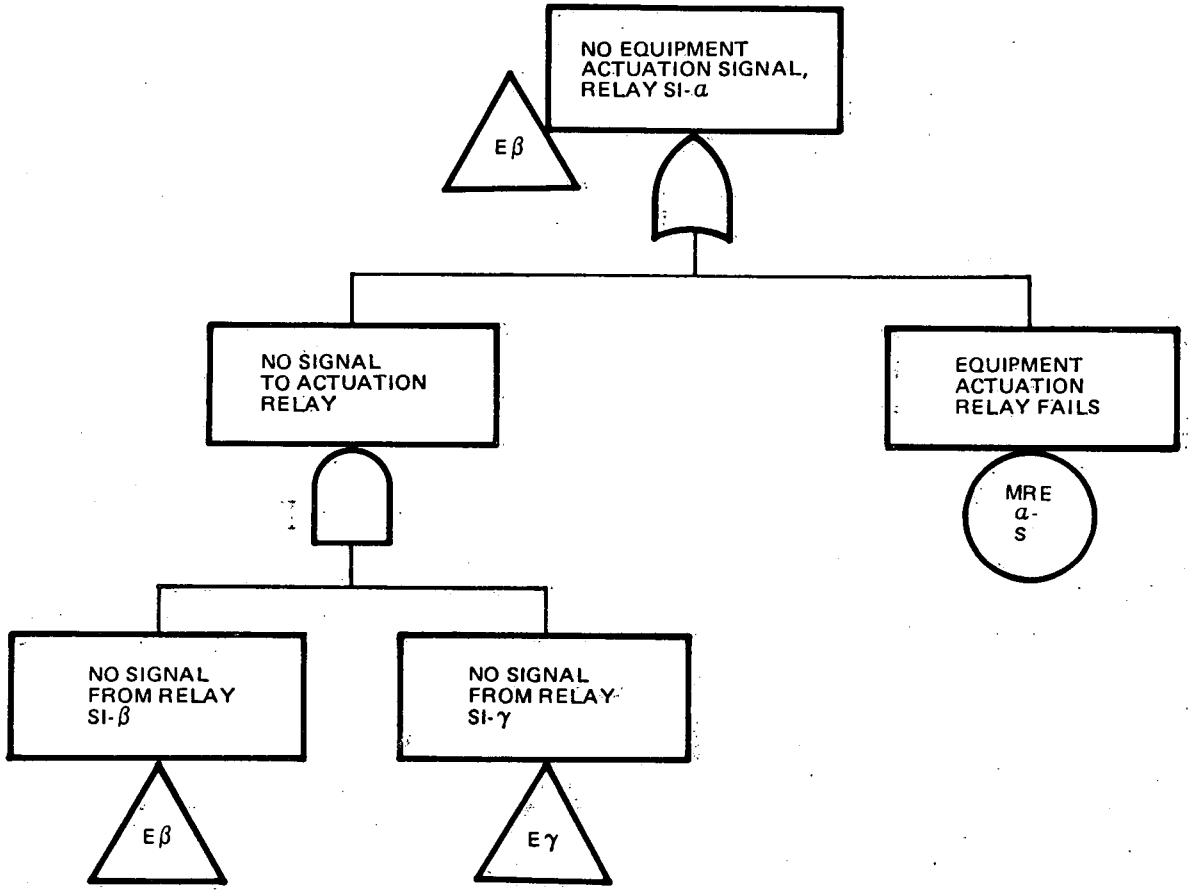


Figure 1.5.2.2.3-7. (Sheet 8 of 23)



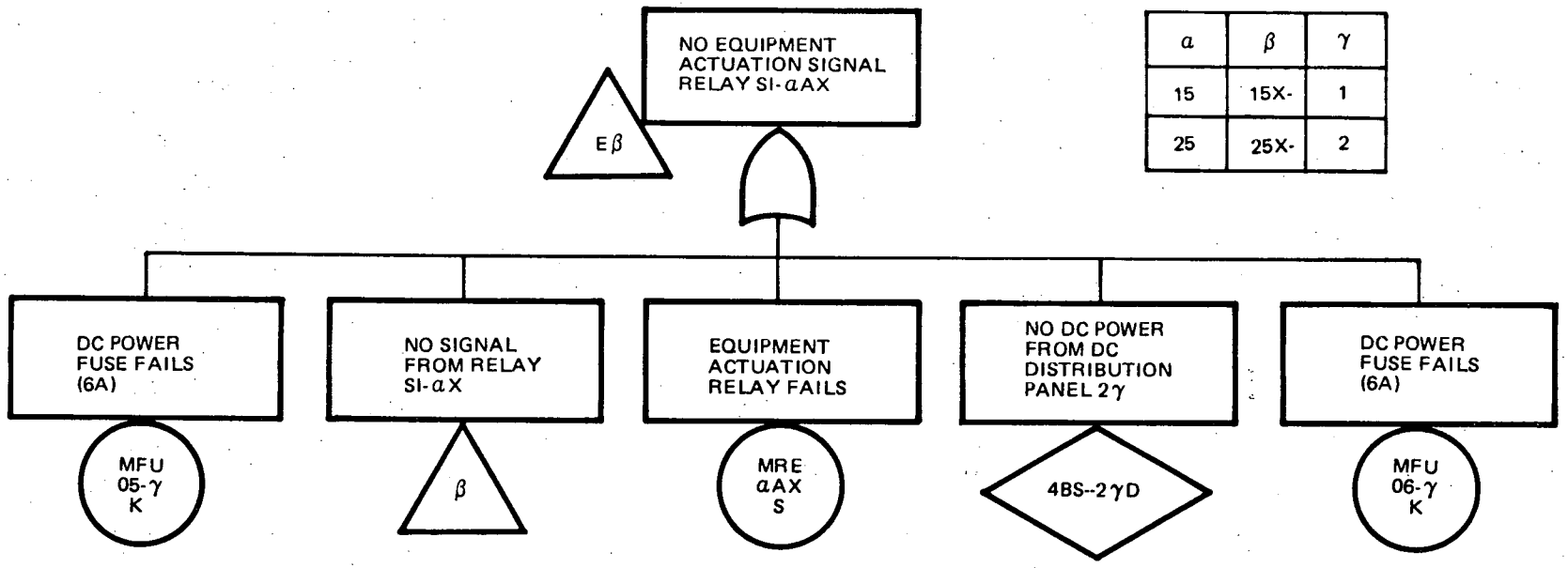
α	β	γ
SI-10X	1	10X-
SI-11X	1	11X-
SI-12X	1	12X-
SI-13X	1	13X-
SI-14X	1	14X-
SI-15X	1	15X-
SI-20X	2	20X-
SI-21X	2	21X-
SI-22X	2	22X-
SI-23X	2	23X-
SI-24X	2	24X-
SI-25X	2	25X-

Figure 1.5.2.2.3-7. (Sheet 9 of 23)



α	β	γ
16X	11X-	14X-
17X	11X-	14X-
18X	11X-	14X-
26X	21X-	24X-
27X	21X-	24X-
28X	21X-	24X-

Figure 1.5.2.2.3-7. (Sheet 10 of 23)



α	β	γ
15	15X-	1
25	25X-	2

Figure 1.5.2.2.3-7. (Sheet 11 of 23)

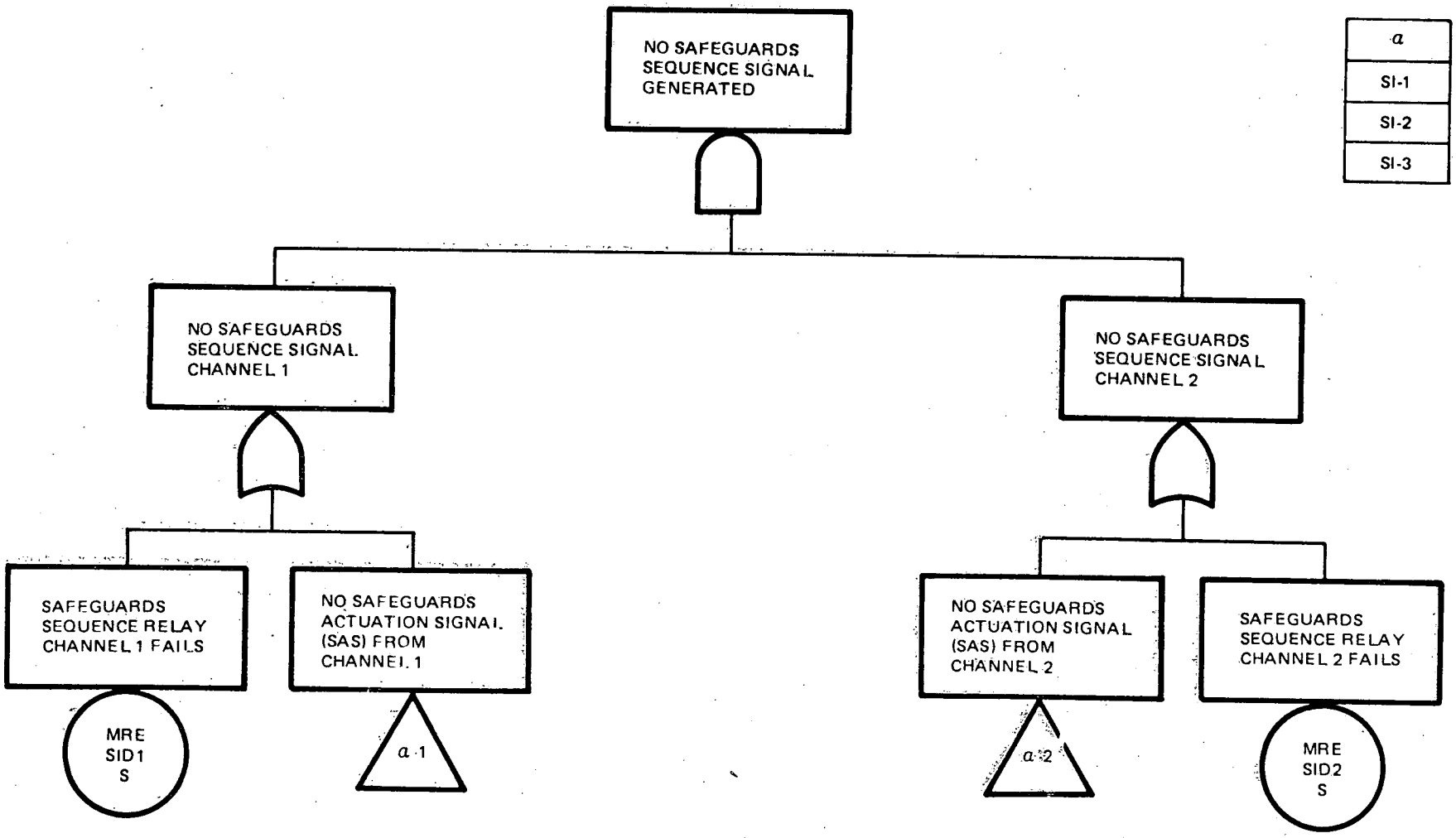
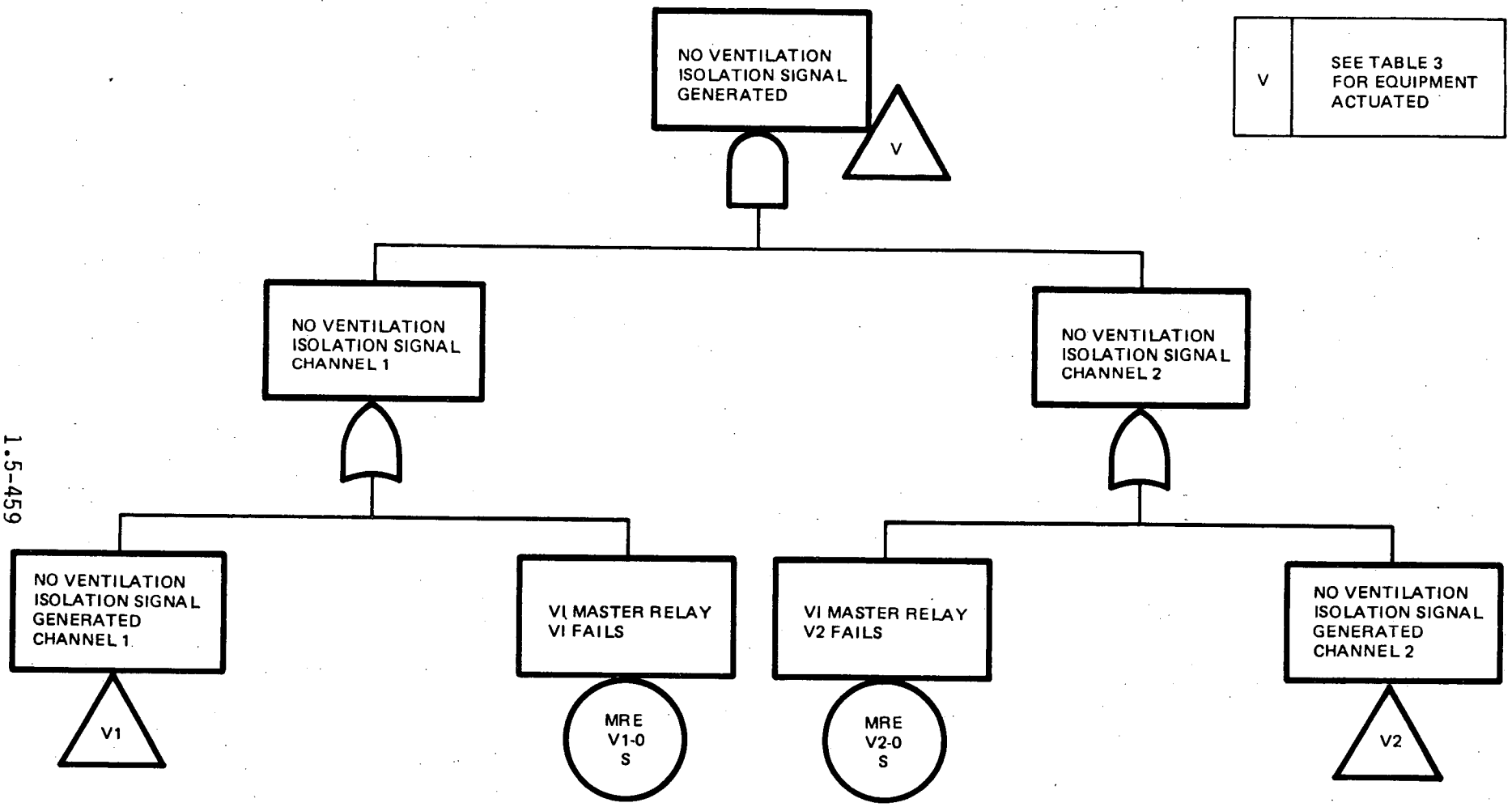


Figure 1.5.2.2.3-7. (Sheet 12 of 23)



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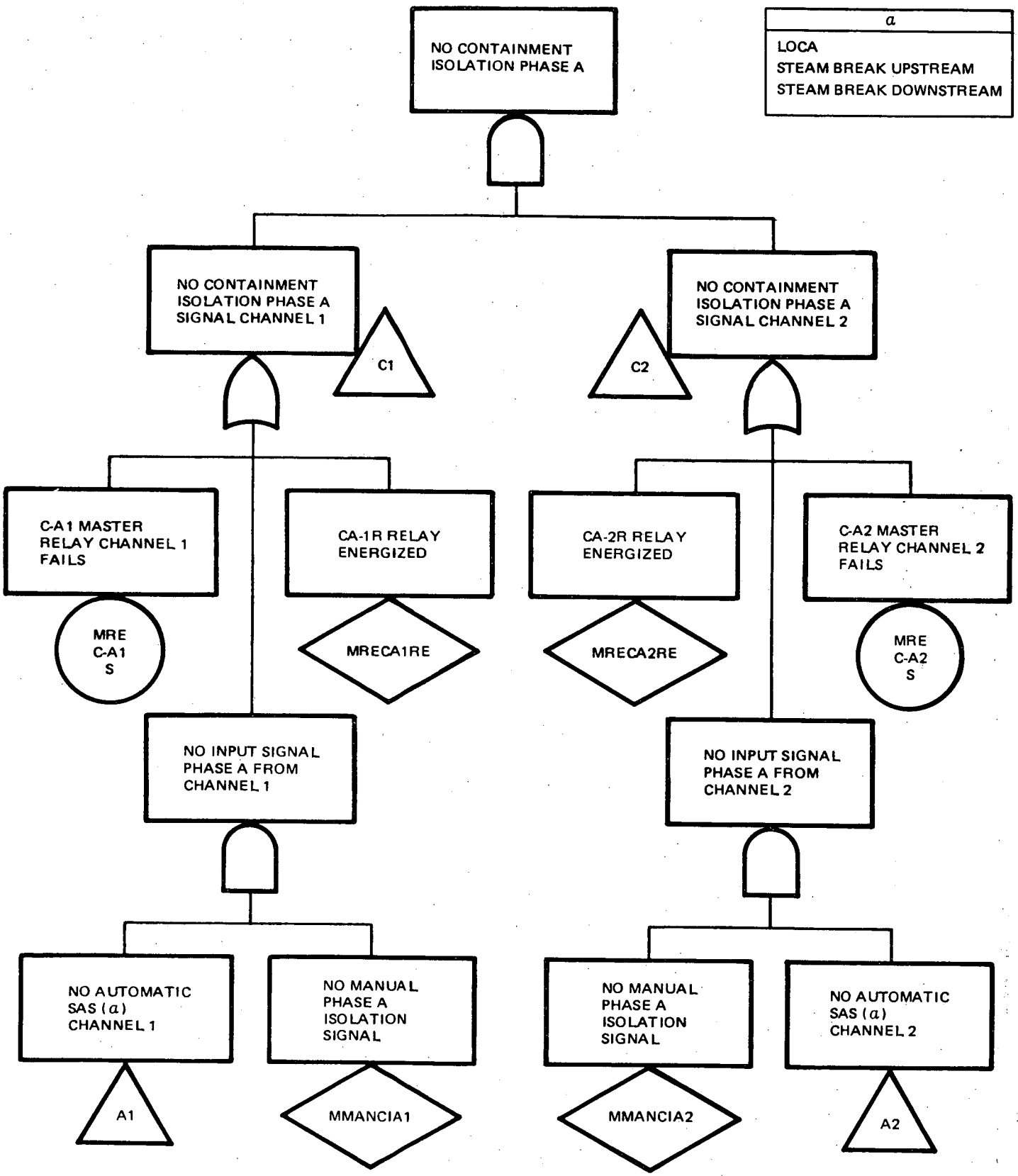

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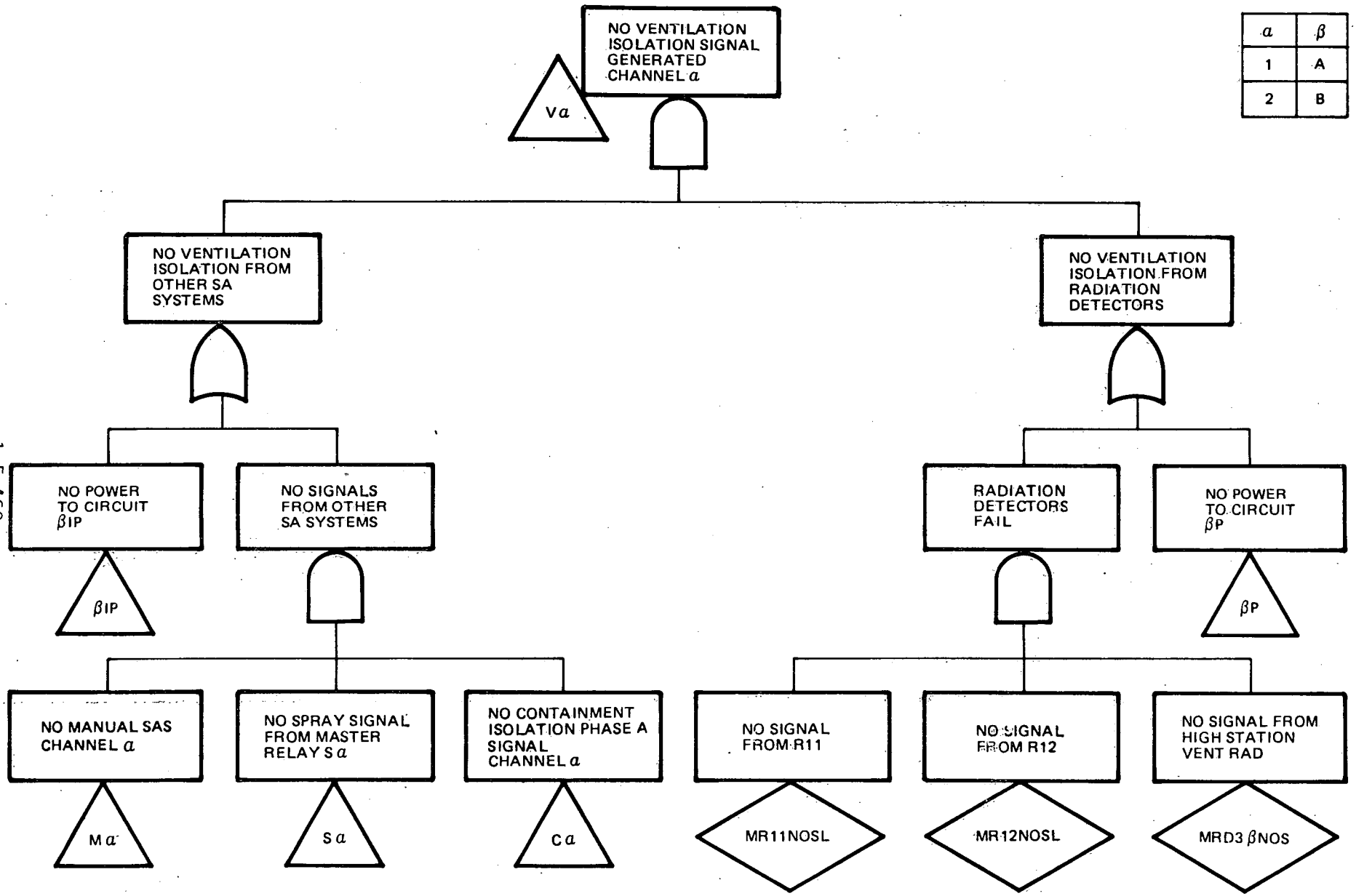

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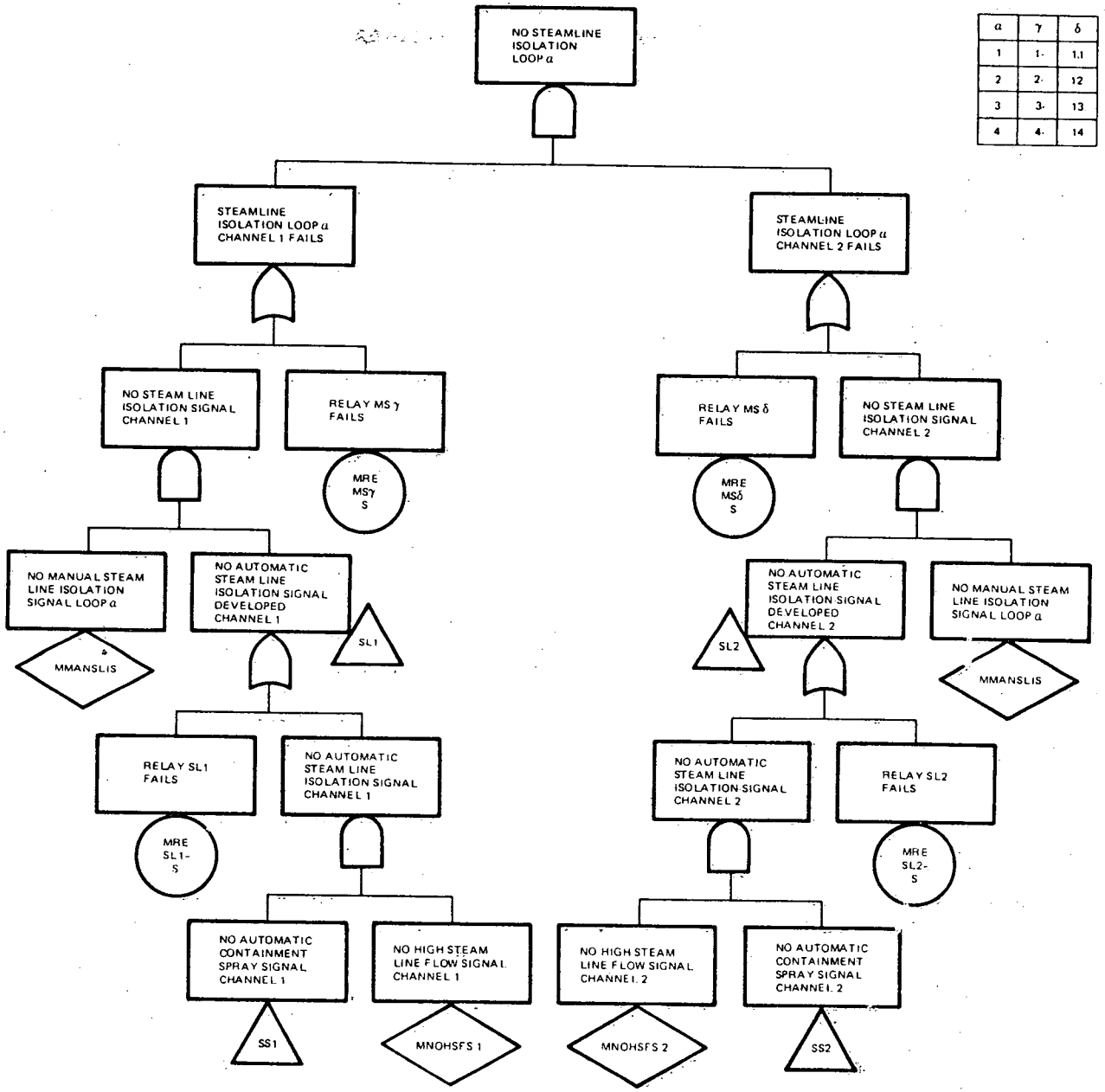
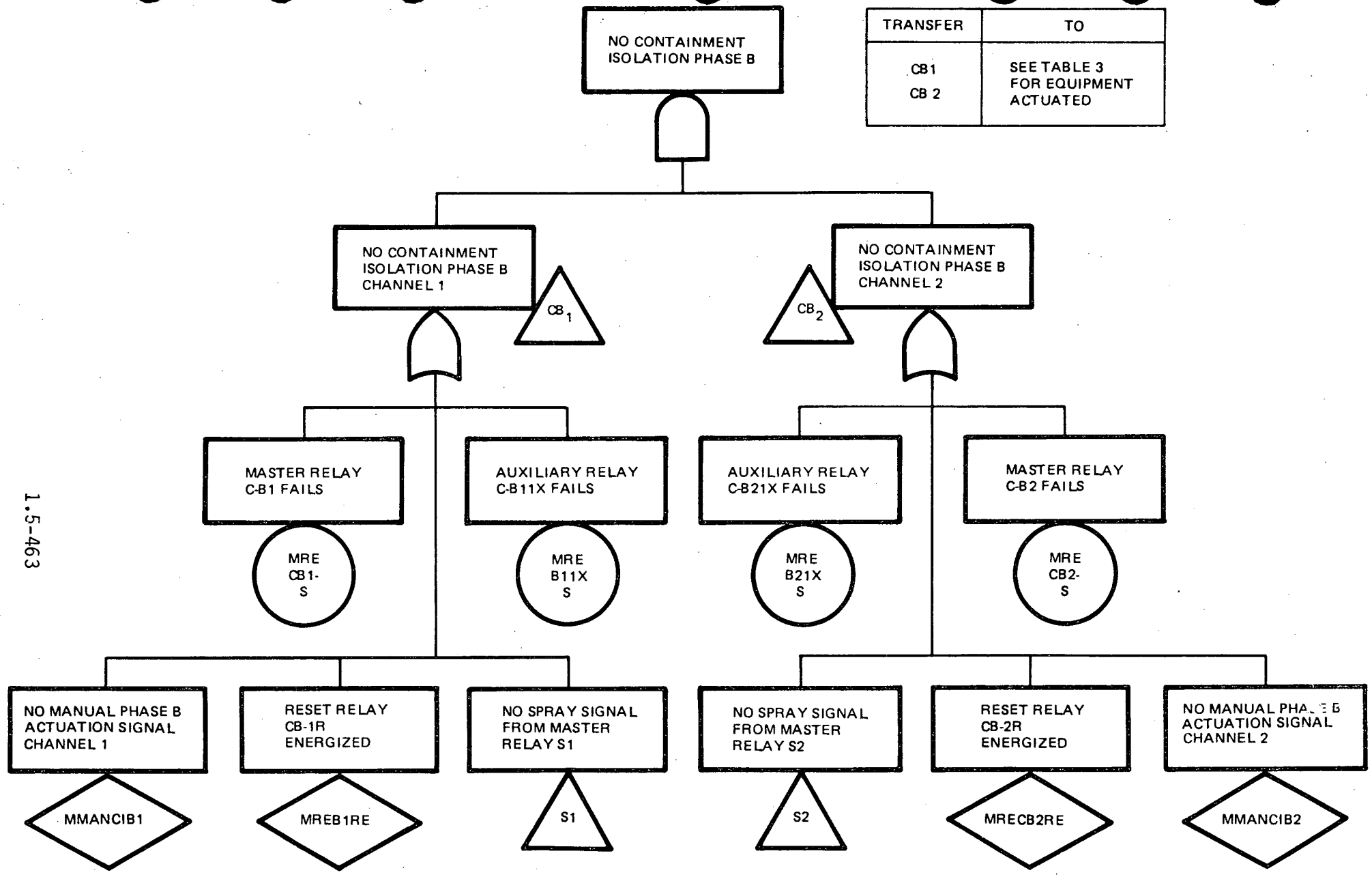


α	γ	δ
1	1-	11
2	2-	12
3	3-	13
4	4-	14

Figure 1.5.2.2.3-7. (Sheet 16 of 23)



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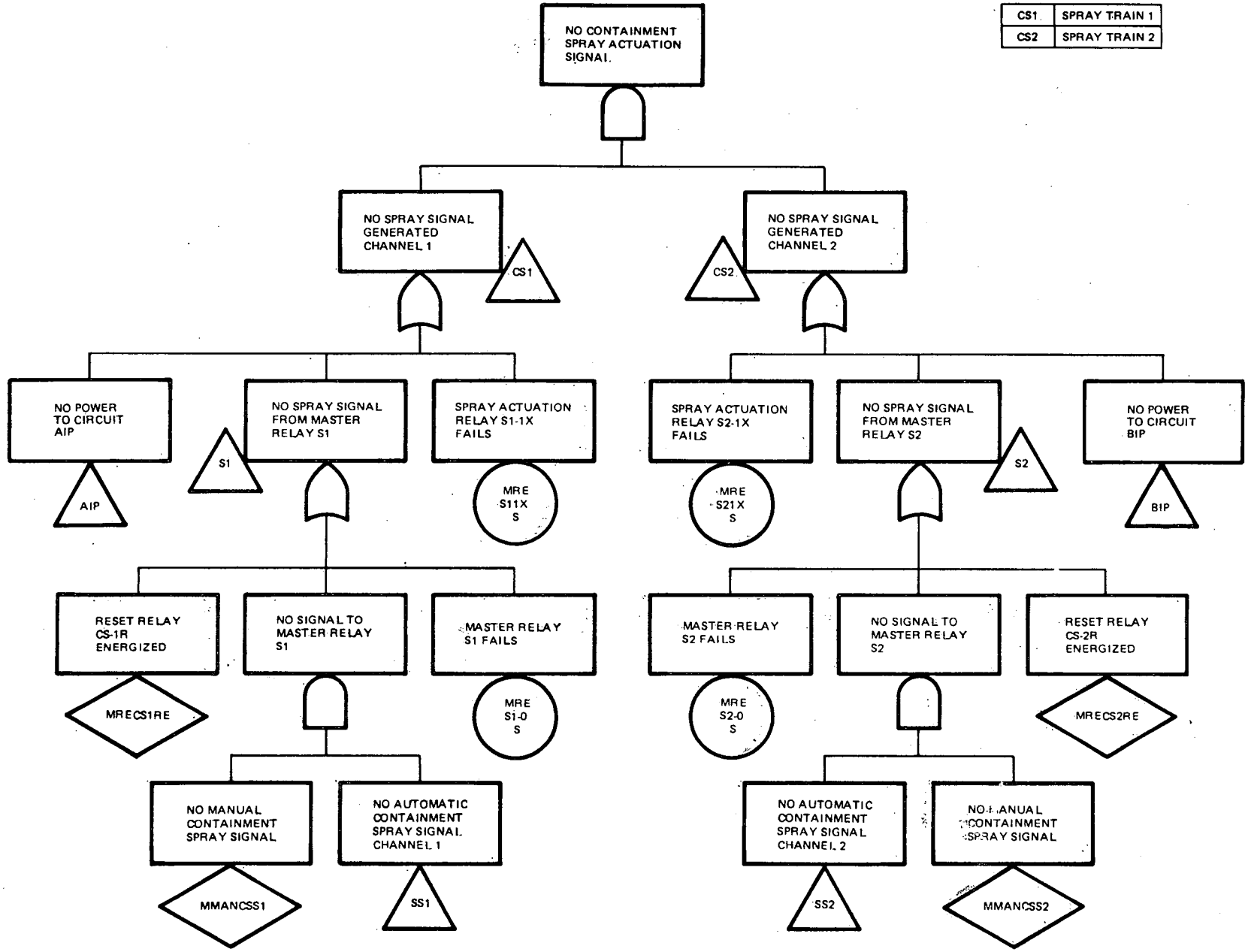

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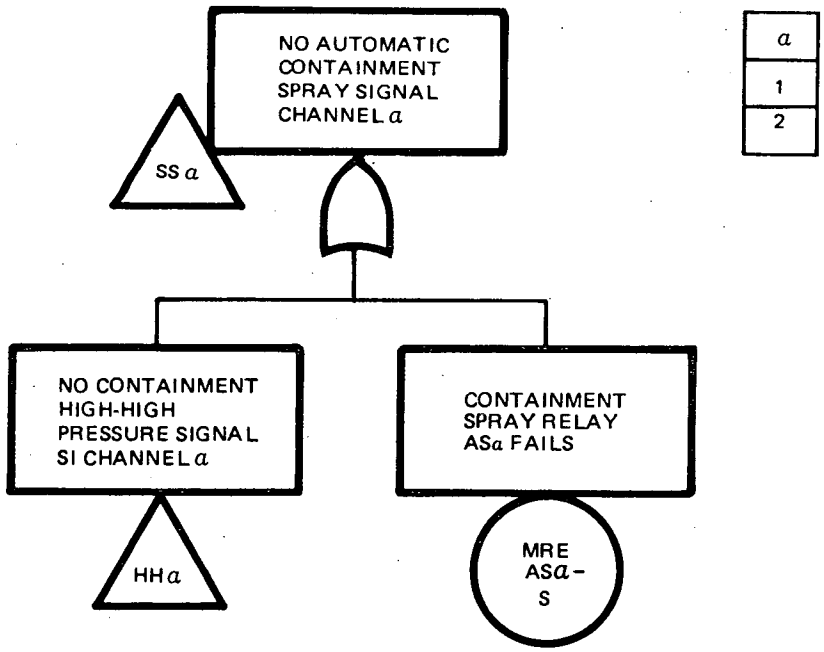

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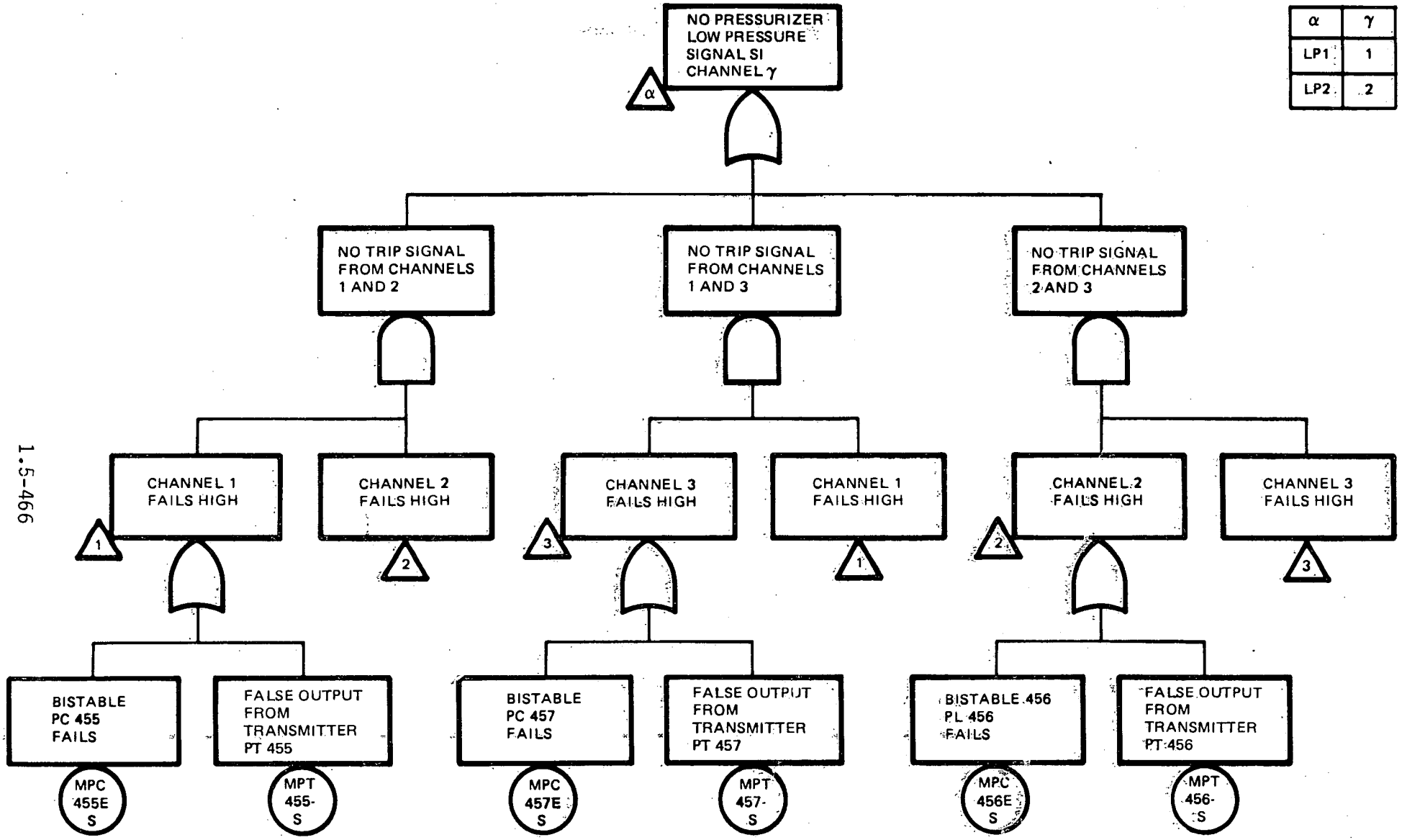


Figure 1.5.2.2.3-7. (Sheet 20 of 23)

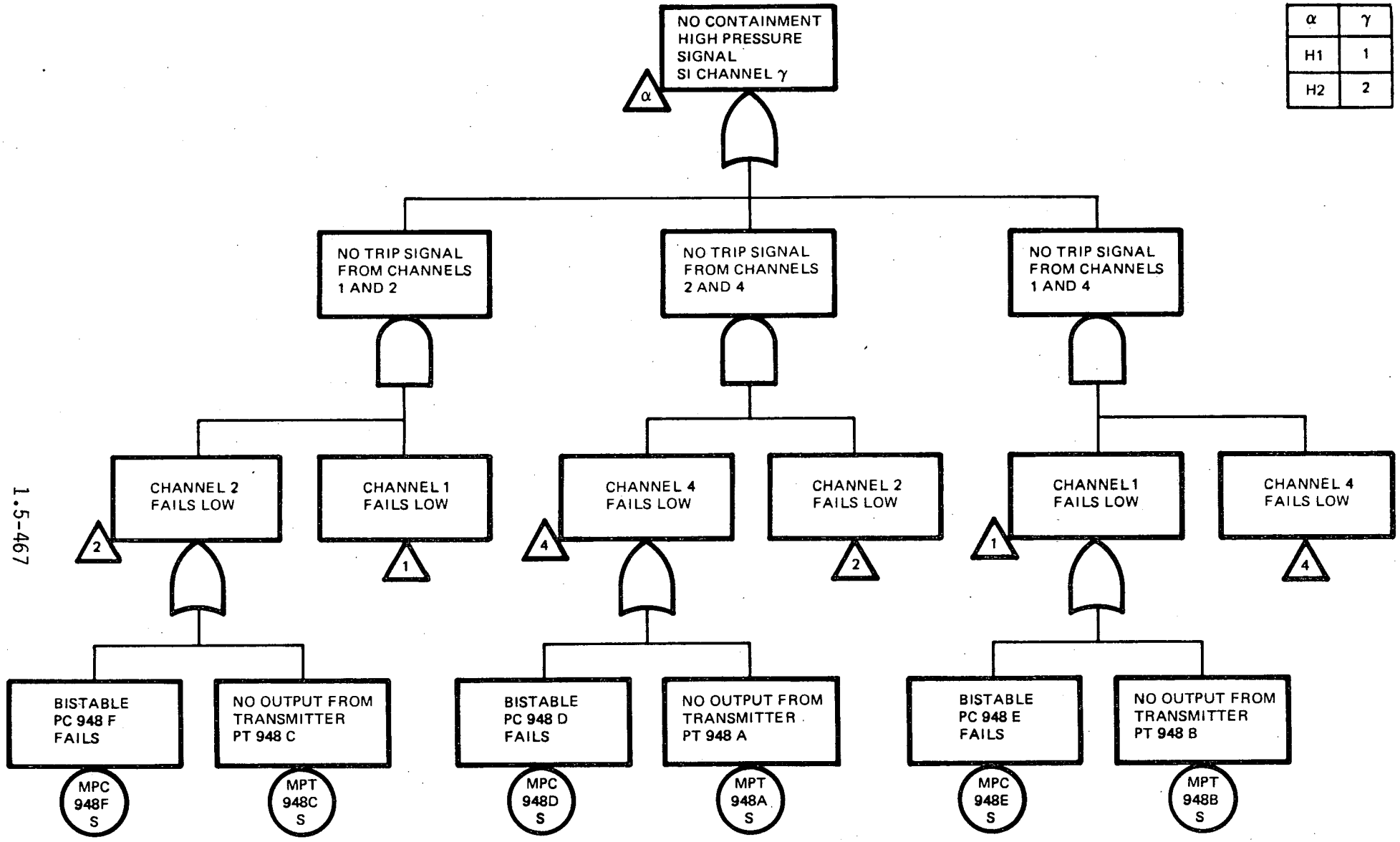
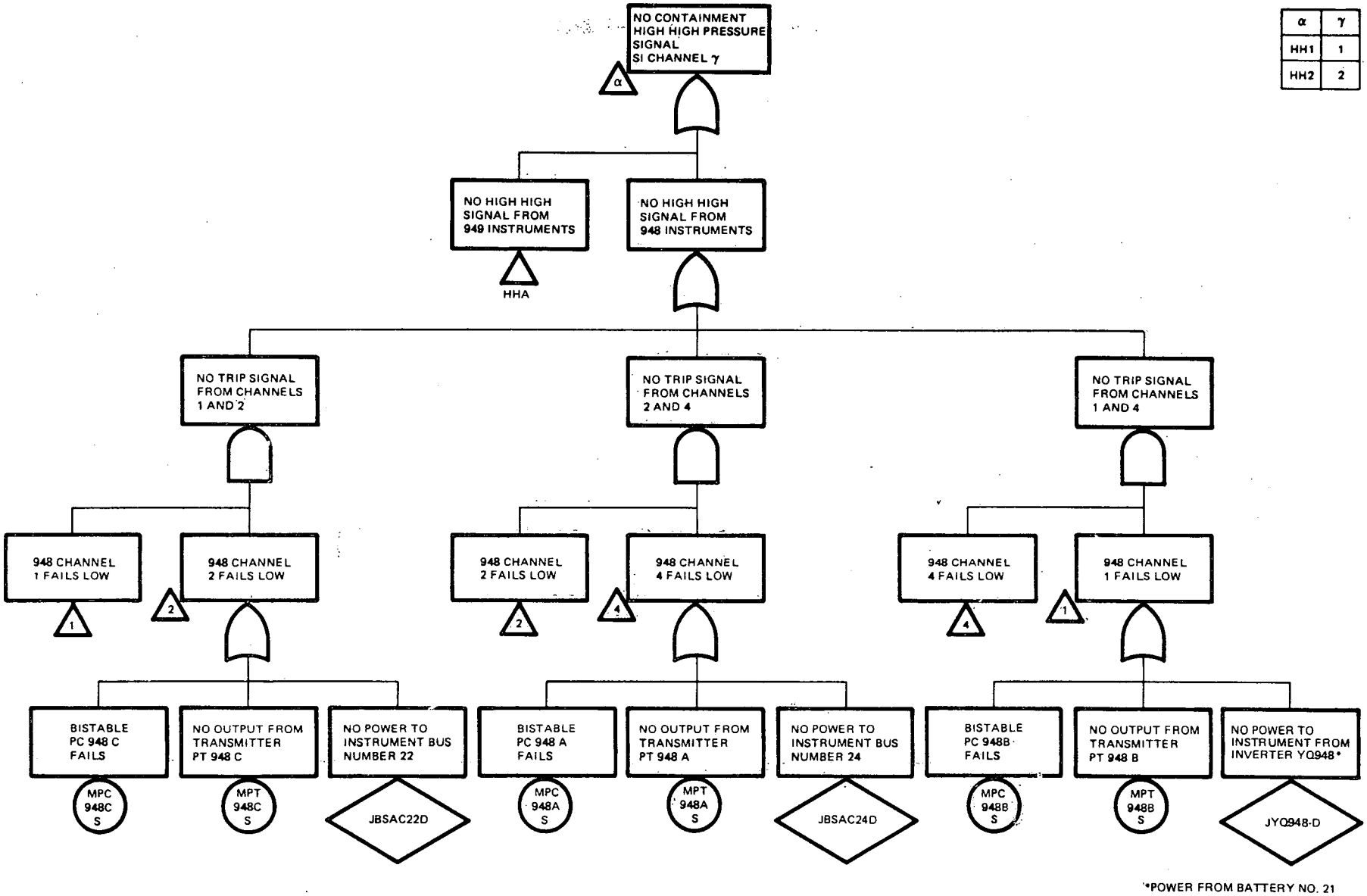


Figure 1.5.2.2.3-7. (Sheet 21 of 23)



α	γ
HH1	1
HH2	2

Figure 1.5.2.2.3-7. (Sheet 22 of 23)

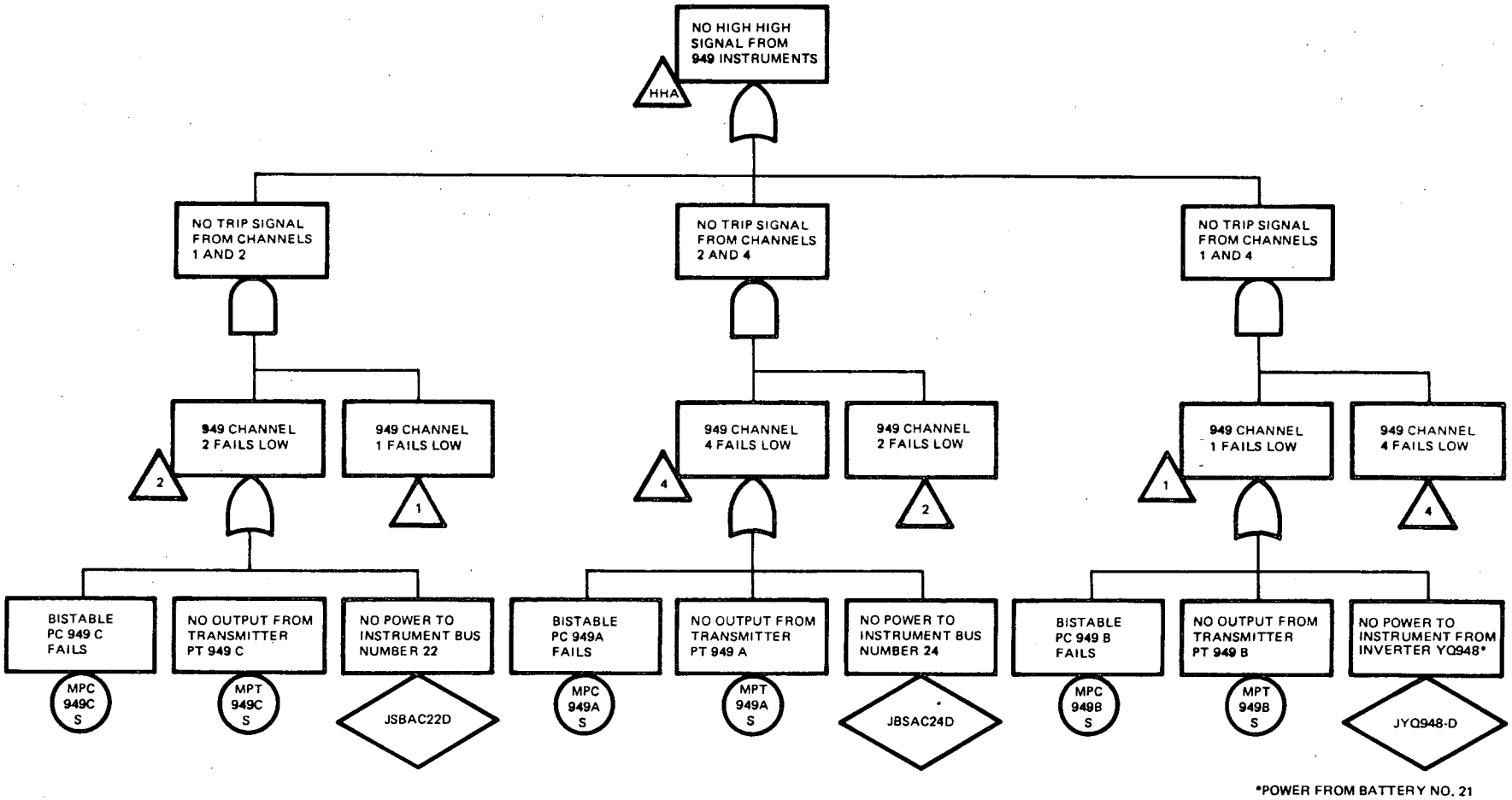


Figure 1.5.2.2.3-7. (Sheet 23 of 23)

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1.5.2.3 Fluid Systems

1.5.2.3.1 Indian Point 2 High Pressure Injection System

1.5.2.3.1.1 Summary.

1.5.2.3.1.1.1 Introduction. The high pressure injection system (HPIS) provides cooling water to the reactor coolant system in case of a medium (2 to 6 inch) pipe break loss of coolant accident (LOCA), a small (less than 2 inches) pipe break LOCA, and a secondary steam break with the system at high pressure (greater than the operating pressure of the accumulators or low pressure injection).

The analysis is carried out under the following conditions:

- Refueling water storage tank (RWST) is available
- Safeguards actuation signal is present
- Success for a medium LOCA is two of three pumps delivering cooling water to two of four injection legs
- Success for a small LOCA is one of three pumps delivering cooling water to one of four injection legs

1.5.2.3.1.1.2 Results. Tables 1.5.2.3.1-1A and 1.5.2.3.1-1B summarize the results for system availability with normal power on all buses and with degraded power on any one bus. The results are compared with the Reactor Safety Study (RSS) results for the small and medium LOCA calculations.

The analysis showed the following dominant contributors to HPIS unavailability:

	Mean
• With Power On All Buses (Medium LOCA)	4.14×10^{-4}
- Single Failures	
• Manual valve 846 from RWST	2.64×10^{-5} (6.37%)
• Motor-operated valve (MOV) 1810 from RWST	2.64×10^{-5} (6.37%)
• Check valve from RWST	7.02×10^{-5} (16.95%)
- Double Failures	
• Two of three safety injection (SI) pumps fail to start	1.47×10^{-4} (35.50%)
• Maintenance on one pump and hardware failure on a second pump	4.83×10^{-5} (11.67%)

	Mean
- Common Cause Failures	9.83×10^{-5} (23.14%)
• With One Bus Lost (Medium LOCA)	1.51×10^{-2}
- Single Failures	
• SI pump on powered bus	7.00×10^{-3} (45.23%)
• SI pump on other powered bus	7.02×10^{-3} (45.23%)
• Maintenance on train with other powered train failed	1.15×10^{-3} (7.61%)
• With Power On All Buses or Lost On One Bus (Small LOCA)	1.86×10^{-4}
- Single Failures	
• Suction valves from RWST	1.23×10^{-4} (66.13%)
- Double Failures	
• Two remaining SI pumps	4.90×10^{-5} (25.26%)
• Two combinations of pump and maintenance	1.61×10^{-5} (8.44%)

1.5.2.3.1.1.3 Conclusions. The HPIS unavailability was dominated by the suction valves and pump failures with associated maintenance and common cause failures.

For a medium LOCA, the system unavailability was 4.14×10^{-4} with full power available and 1.51×10^{-2} with one bus lost.

For a small LOCA, the system unavailability was 1.86×10^{-4} with power on all buses or one bus lost.

Probability distributions of HPIS unavailability are shown in Figures 1.5.2.3.1-1 and 1.5.2.3.1-2 for the medium and small LOCA cases under the states of electric power considered.

1.5.2.3.1.2 System Description.

1.5.2.3.1.2.1 System Function. The HPIS can supply water to all the cold legs when activated by an SI signal. The water is first taken from the boron injection tank (BIT) and later from the refueling water storage tank.

1.5.2.3.1.2.2 System Configuration. A block diagram and simplified piping and instrumentation diagram for the system are shown in Figures 1.5.2.3.1-3 and 1.5.2.3.1-4.

1.5.2.3.1.2.3 System Operation. A minimum of two safety injection pumps are needed (one for small breaks) with pumps and valves automatically arranged to meet this demand. Two of the four injection paths (one of four for small breaks) are needed to deliver water to the core. If this does not occur, operator action is necessary. Pump and valve position lights are provided for indication, as are operating controls for these functions in the central control room (CCR) on the safeguards panel. Normally closed valves 1822A and 1822B on the boron injection tank and normally opened valves 1821 and 1831 are signaled to open. Normally opened valve 1810, RWST suction to pumps, will annunciate "Safeguards Valve Off Normal Position" if it goes closed. (The control power for valve 1810 is normally deenergized. In addition, redundant DC position indication is provided in the CCR when valve 1810 is deenergized.) Most normally opened valves are signaled to open to ensure that the correct position is met. The pumps will first draw the fluid in the BIT as opposed to the RWST because of the 90 psig overpressure. When three out of four level detectors indicate a level of 10% in the BIT, valves 1821, 1831, 1822A, and 1822B will automatically shut to ensure that the nitrogen does not interfere with pump suction from the RWST.

Two main discharge headers deliver water from the SI pumps to four cold leg reactor coolant system injection lines. Safety injection pump 21 is normally aligned to supply one main header, while SI pump 23 is normally aligned to supply the other main header. Safety injection pump 22 is normally aligned to feed both main headers in conjunction with SI pumps 21 and 23. However, following a safeguards actuation signal, if SI pump 21 fails to start after a preset time delay (detected by its breaker failing to close), then crossover header valve MOV-851B will automatically close so that SI pump 22 will only feed the pump 21 main header. Similarly, if SI pump 23 were to fail to start, MOV-851A will automatically close so that pump 22 will only feed the pump 23 main header.

The discharge line valves (856A, 856E, 856C, and 856D) to the reactor coolant system cold legs are normally opened and receive an open signal. If these valves close, the "Safeguards Valve Off Normal Position" alarm will annunciate. These valves are maintained in the open position to allow the rapid addition of boric acid to the RCS in the case of a steam break accident. Flow to each loop is indicated in the CCR on the safeguards panel and any break in the injection line will be indicated by a flow in that line of at least twice that in any of the

other lines. The operator would have to isolate the broken line. The indication that the HPIS is functioning is shown by pressure and flow indications, decreasing tank levels, and alarms.

1.5.2.3.1.2.4 Support Systems. The system is started by a SI signal which starts all three pumps and signals the motor-operated valves to align correctly. Manual actuation from the control room is also possible. Electric power and the RWST are necessary for success of the system. Table 1.5.2.3.1-2 shows the power supplies to the various components of the HPIS. Pump cooling is not critical because of the relatively short time involved in the injection phase and the low temperature of the water in the RWST being pumped.

1.5.2.3.1.2.5 Test Requirements. Each of the three SI pumps is tested monthly (PT-M17) for 20 to 30 minutes. The following elements are also tested:

- Check open MOVs: 842, 843, 1810, 887A, 887B
- Check closed MOVs: 1822A, 1822B, 888A, 888B
- Check open manual valves: 846, 1860, 1807A, 1807B, 1807C, 848A, 848B
- Check closed manual valves: 859A, 859C
- Each pump is started and run for 20 to 30 minutes on recirculation to RWST
- Performance of this test provides the following valve operability verifications:

Valve Verifications	Number
Manual valves remain open	7
Manual valves remain closed	2
MOVs remain open	5
MOVs remain closed	4
Check valves open on demand	4

- No valves are stroked during this test
- The system remains in its normal configuration for this test

The quarterly test (PT-Q11) on each of the injection line MOVs (856A, 856C, 856D, and 856E) ensures that proper injection flow balance valve throttling is maintained by verifying the valve mechanical stop positions (the valves are not stroked during this test).

In addition, the valve surveillance procedure (PT-Q13) tests many of the system valves.

- The following HPIS valves are stroked once during this test:

  - MOVs: 887A, 887B, 1821, 1822A, 1822B, 1831, 851A, 851B

- Except for minor deviations due to actual valve stroking, all systems remain in their normal configurations during this test (no valves are manually isolated or deenergized).

At refueling (cold shutdown), valve surveillance procedure PT-R35 exercises MOVs 1810, 856A, 856C, 856D, and 856E.

Also at refueling (cold shutdown), the PT-R29 full flow test is performed. Each pump is started and run with discharge valve throttled to maintain 1,175-psig discharge pressure with flow to reactor coolant system. The test provides the following valve operability verification:

Valve Verifications	Number
Manual valves remain open	5
MOVs remain open	9
Check valves open on demand	15

MOVs 851A and 851B are stroked once during this test. The test also checks full system flow at refueling (at cold shutdown); all valves (including check valves) observed to pass flow.

Table 1.5.2.3.1-3 gives a summary of the testing performed on the components analyzed in detail in the quantification section.

1.5.2.3.1.2.6 Maintenance Requirements. Maintenance is performed as required. If a pump is found failed, the other two SI pumps are started to verify that they are operable before the pump requiring maintenance is taken out of service. Maintenance can continue for 24 hours. After that, the plant must be shut down.

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1.5.2.3.1.3 Logic Model.

1.5.2.3.1.3.1 Top Event. The fault tree is developed for the event "Insufficient Flow from HPIS." This event appears in the medium and small LOCA event trees. The fault tree is constructed based on the assumption that the RWST and BIT are filled and ready at the time of the safety injection signal. The RWST availability occurs earlier in the event tree.

1.5.2.3.1.3.2 System Fault Tree. Fault tree methodology is used to analyze the HPIS. The top structure of the tree shows three separate maintenance situations in addition to the normal operating situation. The trees carry the operating condition (W, X, Y, Z) as a subscript through each tree to eliminate various pieces of the system under maintenance situations. Figure 1.5.2.3.1-5 shows the top fault tree, and Figure 1.5.2.3.1-6 shows the system fault trees as this system was modeled.

1.5.2.3.1.3.3 Fault Tree Coding. Table 1.5.2.3.1-4 is a list of component events, their failure modes, mean values, and the corresponding codes.

1.5.2.3.1.3.4 Minimal Cutsets. The three valves in the pump suction line from the RWST are single failure points. The safety injection signal has to occur in the event tree to start the system automatically. Pipe failures are discussed in Table 1.5.2.3.1-5.

- Check valve 847 fails to open
- MOV 1810 (deenergized open) closes
- Manual valve 846 (locked open) closes

These letter identified blocks represent groups of components that will be used in the analysis to aid in cutset evaluations. See Figure 1.5.2.3.1-3 for block locations.

Block	Elements in the Block
A	Check Valve 847, MOV 1810, Manual Valve 846
B	Pump Train 21 including Pump 21 Manual Valves 848A, 850A, and Check Valve 849A
C	Pump Train 23 including Pump 23 Manual Valve 848B, 850B, and Check Valve 849B
D	Pump Train 22 including Pump 22 MOVs 887A, B, and 851A or 851B, Check Valve 852A or 852B

Block	Elements in the Block
E	MOV 856A, Check Valve 857E, J, 897A
F	MOV 856E, Check Valve 857L, K, 897C
G	MOV 856C, Check Valves 857C, G
H	MOV 856D, Check Valves 857D, H
K	MOV 1821, 1831, 1822A, B

Using these letter blocks makes it easier to evaluate multiple failure combinations.

All single failures occur in Block A. Combinations of BC, BD, and CD constitute the double failures of two pump trains, which is a failure for a medium break situation. Triple failures include combinations of injection legs in sets of three EFG, EFH, EGH, FGH, and also two triple failures in K when the boron injection tank fails to isolate properly and allows pressurized gas to enter the pump suction lines.

Tables 1.5.2.3.1-6 and 1.5.2.3.1-7 show the additional single event cutsets (for a medium break situation) when pump train 21 (or 23) or 22 are isolated for maintenance.

1.5.2.3.1.4 Quantification: Boundary Condition Electric Power Available on Buses 3A, 5A, and 6A.

1.5.2.3.1.4.1 Quantification of Single Failures.

1.5.2.3.1.4.1.1 Hardware contribution. Each single-event cutset is analyzed using plant specific data:

- Manual valve (MV) 846 on the feed line from the RWST is tested monthly on the recirculation pump test. Therefore, one-half of 30 days is used as the average time period of unknown valve condition:

$$Mean_{MV} = 7.40 \times 10^{-8}/\text{hours} \times 30 \text{ days}/2 \times 24 \text{ hours/day}$$

$$= 2.64 \times 10^{-5}$$

$$Variance_{MV} = 5.89 \times 10^{-15}/\text{hours}^2 \times (360 \text{ hours})^2$$

$$= 7.26 \times 10^{-10}$$

- Motor-operated valve 1810 is flow tested monthly and is deenergized open so it has the same characteristic as the manual valve:

$$Mean_{MOV} = 2.64 \times 10^{-5}$$

$$Variance_{MOV} = 7.26 \times 10^{-10}$$

- Check valve (CV) 847 is flow tested monthly:

$$Mean_{CV} = 7.02 \times 10^{-5}/\text{demand}$$

$$Variance_{CV} = 1.09 \times 10^{-8}$$

- The total hardware contribution for single failures is a serial addition of the components' unavailability in block A and the pipe contribution:

$$Mean_{Singles} = Mean_{MV} + Mean_{MOV} + Mean_{CV}$$

$$= 2.64 \times 10^{-5} + 2.64 \times 10^{-5} + 7.02 \times 10^{-5}$$

$$= 1.23 \times 10^{-4}$$

$$Variance_{Singles} = 1.03 \times 10^{-8}$$

1.5.2.3.1.4.1.2 Test and maintenance contribution. Neither of these two valves is stroked during the quarterly test. The monthly flow test does not change the position of the valves, but verifies the flow through each one. This ensures there will be no contribution to unavailability due to testing.

Any maintenance on these valves will cause the plant to shut down if the valves are removed or placed into a closed position.

1.5.2.3.1.4.1.3 Human error contribution. No significant human error is envisioned for valves because flow tests ensure an open flow path after any valve manipulation that may occur at refueling. In addition, MOV1810 is deenergized open with redundant position indication in the CCR, and each month, MV846 is verified to be locked open.

Table 1.5.2.3.1-8 summarizes the unavailability contributors for single failures.

1.5.2.3.1.4.2 Quantification of Double Failures.

1.5.2.3.1.4.2.1 Hardware contribution. Two element cutsets are determined, as noted in Section 1.5.2.3.1.3.4, by combinations of any two pump trains not providing flow to the injection headers. These trains are referred to as block B or C for train 21 or 23 and block D for train 22.

Some elements in each train are flow tested each month so the average of 30 days/2 will apply to those valves in each of the trains as the average time of unknown valve position. Other valves are only flow tested at refueling even though motor-operated valves 851A and 851B and MOVs 887A and 887B in the pump train 22 suction line are stroked during the quarterly test. Each of the following valves will be evaluated to determine the average time since a flow test verified the proper position of the gate within the valve.

The block B values are:

Component Failure Mode	Subscript	Mean	Variance
SI pump 21 fails to start	P	6.41×10^{-3}	7.78×10^{-6}
Manual valve 848A fails closed (30 days/2 x 24 hours/day x $7.40 \times 10^{-8} = 2.64 \times 10^{-5}$)	MV1	2.64×10^{-5}	7.26×10^{-10}
Check valve fails to open	CV	7.02×10^{-5}	1.09×10^{-8}
Manual valve 850A fails closed* (6,570 hours x 7.40×10^{-8}/hours $= 4.86 \times 10^{-4}$)	MV2	4.86×10^{-4}	2.60×10^{-8}

The mean unavailability of block B is then:

$$\text{Mean}_B = \text{Mean}_P + \text{Mean}_{MV1} + \text{Mean}_{CV} + \text{Mean}_{MV2}$$

$$= 6.41 \times 10^{-3} + 2.64 \times 10^{-5} + 7.02 \times 10^{-5} + 4.86 \times 10^{-4}$$

$$= 7.00 \times 10^{-3}$$

$$\text{Variance}_B = 7.16 \times 10^{-6}$$

*A 6,570-hour interval (one-half of 18-month refueling cycle) was used as the time that flow was not known to have passed the valve.

Block C has the same values because the two blocks are symmetrical. However, block D has several different components which yield the following block values.

Component Failure Mode	Subscript	Mean	Variance
SI pump 22 fails to start	P	6.41×10^{-3}	7.78×10^{-6}
MOV 887A transfers closed (30 days/2 x 24 hours/day x $7.40 \times 10^{-8} = 2.5 \times 10^{-5}$)	MOV1	2.64×10^{-5}	7.26×10^{-10}
MOV 887B transfers closed	MOV2	2.64×10^{-5}	7.26×10^{-10}
MOV 851A transfers closed* (6,570 hours x 7.40×10^{-8}/hours $= 4.86 \times 10^{-4}$)	MOV3	4.86×10^{-4}	2.81×10^{-8}
Check valve 852A fails to open	CV	7.02×10^{-5}	1.09×10^{-8}

The mean unavailability of block D is then:

$$\begin{aligned} \text{Mean}_D &= \text{Mean}_P + \text{Mean}_{MOV1} + \text{Mean}_{MOV2} + \text{Mean}_{MOV3} + \text{Mean}_{CV} \\ &= 6.41 \times 10^{-3} + 2.64 \times 10^{-5} + 2.64 \times 10^{-5} + 4.86 \times 10^{-4} \\ &\quad + 7.02 \times 10^{-5} \\ &= 7.02 \times 10^{-3} \end{aligned}$$

$$\text{Variance}_D = 7.16 \times 10^{-6}$$

The block D evaluation is used in the flow path to line 56, but the alternate path to line 16 has a similar set of values. The pumps failing to start represents the majority of the contribution to unavailability. Consequently, the two types of trains have nearly equivalent values of unavailability. Therefore, the calculation of the two element cutsets will be made using the higher values (block D) as a slightly conservative simplification.

Using discrete probability distribution (DPD) arithmetic for the three combinations of two trains failing coincidentally, yields the following:

$$\begin{aligned} \text{Mean}_{\text{Pump Trains}} &= (B \text{ and } C) + (B \text{ and } D) + (C \text{ and } D) \\ &= 1.47 \times 10^{-4} \\ \text{Variance} &= 7.87 \times 10^{-9} \end{aligned}$$

*A 6,570-hour interval (one-half of 18-month refueling cycle) was used as the time that flow was not known to have passed the valve.

1.5.2.3.1.4.2.2 Test contribution. During the monthly test, no valves are stroked and the system is in the normal configuration. However, during the quarterly in-service valve test, the four valves in block D (pump 22 train) are each stroked for a 5-minute interval giving a total of 15 minutes each quarter when the train may not be able to provide flow to the needed line. During the stroke, the valve will not be completely closed for the full 5 minutes, but the total test time will be used as a conservative estimate. Estimated one standard deviation on the 5-minute time is 3 minutes. Therefore, the variance of one valve is $(3/60)^2$.

Unavailability due to tests = 3 x 0.083 hours/test/2,190 hours/quarter

$$\text{Mean}_T = 1.1 \times 10^{-4}$$

$$\text{Variance}_T = (3)^2(3/60)^2/(2190)^2$$

$$= 4.7 \times 10^{-9}$$

With train 22 (block D) unavailable, the other trains must both operate to meet the required two pumps operating. Therefore, each element in blocks B and C becomes a single element cutset, and for both blocks, the following values are obtained (using values from Section 1.5.2.3.1.4.2.1):

$$\text{Mean}_{2B} = \text{Mean}_B + \text{Mean}_C$$

$$= 7.00 \times 10^{-3} + 7.02 \times 10^{-3}$$

$$= 1.40 \times 10^{-2}$$

Then the unavailability due to these tests is:

$$\text{Mean}_{Test} = \text{Mean}_{2B} \times \text{Mean}_T$$

$$= 1.40 \times 10^{-2} \times 1.1 \times 10^{-4}$$

$$= 1.96 \times 10^{-6}$$

1.5.2.3.1.4.2.3 Maintenance contribution. Valve maintenance was considered to be performed during nonoperating hours or with the valves in their normal injection system position. However, observations of pump maintenance during the past 4 years lead to the following unavailability of a pump train because maintenance during operating hours:

$$\text{Mean}_{Maintenance} = 1.15 \times 10^{-3} \quad \text{(Section 1.5.1.3)}$$

$$\text{Variance}_{Maintenance} = 1.03 \times 10^{-7}$$

With three pump trains there are three ways to have maintenance unavailability because each pump is equally likely to require maintenance. The failure of two pumps is given in Section 1.5.2.3.1.4.2.2.

$$\text{Mean}_{3\ \text{Pump Maintenance}} = 3 \times \text{Mean}_{\text{Maintenance}} \times \text{Mean}_{2B}$$

(see Section 1.5.2.3.1.4.2.2)

$$= 3 \times 1.15 \times 10^{-3} \times 1.40 \times 10^{-2}$$

$$= 4.83 \times 10^{-5}$$

1.5.2.3.1.4.2.4 Human error contribution. Because the system starts automatically on a safety injection signal, human interaction does not become a major factor until the recirculation phase. The procedures of the monthly and quarterly tests appear to minimize human error (i.e., such as opening and then closing each valve before proceeding to the next valve). Therefore, no significant contribution to system unavailability was envisioned for this system.

1.5.2.3.1.4.2.5 Other causes. Most of the observed coupled failures in the industry involved motor or air-operated valves that had to change position on demand. The frequent partial and full refueling system tests indicate that an unforeseen common cause failure is of low frequency. This state of knowledge is expressed by taking a β-factor with a range of 1.0×10^{-3} to 5.0×10^{-2} which yields a mean and variance of:

$$\alpha_\beta = 1.4 \times 10^{-2}$$

$$\beta_\beta^2 = 6.1 \times 10^{-4}$$

This β-factor is assessed for the common cause failure of the trains failing coincidentally:

$$\text{Mean} = 1.4 \times 10^{-2} \times 7.02 \times 10^{-3}$$ (see Section 1.5.2.3.1.4.2.1)

$$= 9.83 \times 10^{-5}$$

1.5.2.3.1.4.2.6 Double failure contribution. Table 1.5.2.3.1-9 summarizes the double failure contributions.

1.5.2.3.1.4.3 Triple Failures. From Section 1.5.2.3.1.4.2.2 it was found that mean unavailability of two injection paths being blocked while a third was being tested yielded a triple failure. If the third path fails coincident with the testing of the other two, an approximate value of the unavailability is:

$$\text{Mean}_{3\ \text{Legs}} = (\text{Mean}_{\text{Leg}})^3 = 1.25 \times 10^{-10}$$

The BIT tank not isolating to prevent gas in the suction line (block K valves) after the tank level reaches a low level has two triple failures:

- MOV 1831 fails to close on signal
- MOV 1821 fails to close on signal
- Either 1822 A or B fails to close

$$\text{Mean}_{\text{BIT Fails to Isolate}} = 2 \times (2.32 \times 10^{-3})^3$$

$$= 4.51 \times 10^{-8}$$

Because three out of four level indicators initiate the signal to isolate, this failure mode was considered unlikely and was not quantified further. Closing logic is dominated by transmitter failure which is on the order of 10^{-12} in this case.

Triple failures were dominated by single and double failures.

1.5.2.3.1.4.4 System Unavailability. Table 1.5.2.3.1-10 shows the results that have been derived for the mean values of the dominant contributors to HPIS unavailability. These contributors are the basis for the uncertainty analysis. The mathematical expression for the unavailability of the system, in terms of the unavailabilities of the dominant contributors, is defined here and evaluated using DPD arithmetic:

$$Q = Q_{\text{Singles}} + Q_{\text{Pump Trains}} + Q_{\text{Test}} + Q_{\text{Maintenance}} + Q_{\text{Other}}$$

$$= 4.14 \times 10^{-4}$$

1.5.2.3.1.4.5 Quantification: Offnormal Conditions.

1.5.2.3.1.4.5.1 Boundary condition degraded electric power. For the HPIS the only degraded electric power states analyzed were the loss of single bus states (3A, 5A, or 6A). This is because their frequency of occurrence dominates the loss of two bus states, as discussed in Section 1.3.2 and Section 1.5.2.2.1.

Loss of bus 3A causes block D (pump 22) to become unavailable. This has the same quantitative effect as having the train out for maintenance. From Section 1.5.2.3.1.4.2.1, the unavailability of block B (or C) is given as:

$$\text{Mean}_B = 7.00 \times 10^{-3} \text{ and } 7.02 \times 10^{-3}, \text{ respectively}$$

Both blocks B and C must operate. If either B or C fails, the system fails:

$$Mean_{BC} = Mean_B + Mean_C$$

$$= 7.00 \times 10^{-3} + 7.02 \times 10^{-3}$$

$$= 1.40 \times 10^{-2}$$

This unavailability is the same for the cases of BD and CD.

Loss of bus 5A or 6A disables a pump train plus two of the four MOVs on the BIT line to pump suction. Either valve with a good bus must close to isolate the BIT. This assumes that valve 1822 on the lost bus was closed as normal when the power was lost. The mean unavailability contribution using DPD arithmetic is:

$$Mean_{BIT_{Valve}} = (2.32 \times 10^{-3})^2 = 5.35 \times 10^{-6}$$

This is dominated by the pump train unavailability. Therefore, the system unavailability given here will apply to each case in which one bus is lost. Using DPD arithmetic yields the following:

Mean:	1.51×10^{-2}
Variance:	2.00×10^{-4}
5th Percentile:	5.90×10^{-3}
Median:	1.40×10^{-2}
95th Percentile:	2.80×10^{-2}

Table 1.5.2.3.1-11 summarizes the contributors to one bus lost unavailabilities.

1.5.2.3.1.4.5.2 Small LOCA case. With one bus lost, two of two pumps must fail to provide flow:

$$Mean = (Mean_B)^2$$

$$= (7.02 \times 10^{-3})^2$$

$$= 4.9 \times 10^{-5}$$

Also, if one train is down for maintenance when a bus is lost, then the remaining train is a single failure train.

This unavailability is computed as follows with two ways the combination could happen:

$$\text{Mean}_{1\ \text{Bus Down + Maintenance}} = \text{Mean}_{\text{Maintenance}} \times 2\ \text{Mean}_{B}\ (\text{train B})$$

$$= 1.15 \times 10^{-3} \times 2 \times 7.02 \times 10^{-3}$$

$$= 1.61 \times 10^{-5}$$

With one bus out, the mean for the system is:

$$\text{Mean}_{\text{System}} = \text{Mean}_{\text{Single}} + \text{Mean}_{2\ \text{Pump Trains}}$$

$$+ \text{Mean}_{1\ \text{Bus Down + Maintenance}}$$

$$= 1.23 \times 10^{-4} + 4.9 \times 10^{-5} + 1.61 \times 10^{-5}$$

$$= 1.86 \times 10^{-4}$$

In addition, DPD arithmetic yields these values:

Mean:	1.86×10^{-4}
Variance:	1.01×10^{-7}
5th Percentile:	3.27×10^{-5}
Median:	1.69×10^{-4}
95th Percentile:	4.38×10^{-4}

With all power buses available, the results are the same as the one bus lost case because failure of safety injection pumps 21 and 23 (detected by pump motor circuit breakers failing to close or remain closed) will close MOVs 851A and 851B, thereby blocking flow from safety injection pump 22 to the discharge injection headers. This is a conservative calculation because operator actions to recover flow from pump 22 are not taken into account.

Table 1.5.2.3.1-12 summarizes these cases for a small LOCA.

TABLE 1.5.2.3.1-1A

INDIAN POINT 2 HPIS UNAVAILABLE - MEDIUM LOCA

Condition Transferred from Event Tree Power Available	LOCA	Mean	Variance	5th Percentile	Median	95th Percentile
Power Available on All Buses	Medium	4.14×10^{-4}	3.67×10^{-8}	1.97×10^{-4}	3.66×10^{-4}	8.31×10^{-4}
Power Lost on One Bus	Medium	1.51×10^{-2}	2.01×10^{-4}	5.91×10^{-3}	1.42×10^{-2}	2.83×10^{-2}
WASH-1400 Comparison	Medium	Not Given	Not Given	7.00×10^{-3}	1.20×10^{-2}	2.90×10^{-2}

TABLE 1.5.2.3.1-1B

INDIAN POINT 2 HPIS UNAVAILABLE - SMALL LOCA

Condition Transferred from Event Tree Power Available	LOCA	Mean	Variance	5th Percentile	Median	95th Percentile
Power Available on All Buses	Small	1.86×10^{-4}	1.01×10^{-7}	3.27×10^{-5}	1.69×10^{-4}	4.38×10^{-4}
Power Lost on One Bus	Small	1.86×10^{-4}	1.01×10^{-7}	3.27×10^{-5}	1.69×10^{-4}	4.38×10^{-4}
WASH-1400 Comparison	Small	Not Given	Not Given	4.40×10^{-3}	8.60×10^{-3}	2.70×10^{-2}

TABLE 1.5.2.3.1-2

INDIAN POINT 2 HPIS POWER SUPPLIES

Component	Power Supply
SI Pump 21	480V Bus 5A
SI Pump 22	480V Bus 3A
SI Pump 23	480V Bus 6A
MOV 1821	MCC 26A/Bus 5A
MOV 1831	MCC 26B/Bus 6A
MOV 1822A	MCC 26A/Bus 5A
MOV 1822B	MCC 26B/Bus 6A
MOV 851A	MCC 26A/Bus 5A
MOV 851B	MCC 26B/Bus 6A

TABLE 1.5.2.3.1-3

INDIAN POINT 2 TESTING REQUIREMENTS

Component	Testing/Inspection
SI Pumps 21, 22, 23	Start and run 20 to 30 minutes monthly and run on full flow test at refueling
MOV 1810	Verify open monthly; stroke at refueling
MOV 887A, B	Verify open monthly and stroke quarterly
MOV 1821; 1831; 1822A, B,	Stroke quarterly
MOV 851A, B	Verify open at refueling and stroke quarterly
MOV 1822A, B; 888A, B	Verify closed monthly
Manual Valves 846; 848A, B	Verify open monthly
MOV 856A, C, D, E	Stroke closed, then open at refueling. Verify open at refueling
Check Valve 847	Verify open monthly
Manual Valves 850A, B	Stroke closed, then open at refueling. Verify open at refueling
Check Valves 849A, B; 852A, B; 857J, E, K, L, G, C, D, H; 897A, C	Verify open at refueling

TABLE 1.5.2.3.1-4

INDIAN POINT 2 LIST OF COMPONENTS

Component	Failure Mode	Fault Tree Coding	Mean Failure Rate	H/D*	Data Source	Variance
Check Valves						
857C, D, E, G, H, J, K, L	Fails to Open	HCV (Valve) Q	7.02×10^{-5}	D	3	1.09×10^{-8}
897A, C	Fails to Open	HCV (Valve) Q	7.02×10^{-5}	D	3	1.09×10^{-8}
849A, B	Fails to Open	HCV (Valve) Q	7.02×10^{-5}	D	3	1.09×10^{-8}
852A, B	Fails to Open	HCV (Valve) Q	7.02×10^{-5}	D	3	1.09×10^{-8}
847	Fails to Open	HCV (Valve) Q	7.02×10^{-5}	D	3	1.09×10^{-8}
Manual Valves						
850A, B	Transferred Closed	HXV (Valve) C	7.40×10^{-8}	H	1	5.89×10^{-15}
848A, B	Transferred Closed	HXV (Valve) C	7.40×10^{-8}	H	1	5.89×10^{-15}
846	Transferred Closed	HXV (Valve) C	7.40×10^{-8}	H	1	5.89×10^{-15}
Motor-Operated Valves						
1810	Transferred Closed	HMV (Valve) C	7.40×10^{-8}	H	1	5.89×10^{-15}
856A, C, D, E	Transferred Closed	HMV (Valve) C	7.40×10^{-8}	H	1	5.89×10^{-15}
851A, B	Transferred Closed	HMV (Valve) C	7.40×10^{-8}	H	1	5.89×10^{-15}

*Hourly rates (H) are modified depending on last known good position and flow check. Demand (D) is failure to operate on demand.

TABLE 1.5.2.3.1-4 (continued)

INDIAN POINT 2 LIST OF COMPONENTS

Component	Failure Mode	Fault Tree Coding	Mean Failure Rate	H/D*	Data Source	Variance
887A, B	Transferred Closed	HMV (Valve) Q	7.40×10^{-8}	H	1	5.89×10^{-15}
1821, 1831	Fails to Close	HMV (Valve) S	2.32×10^{-3}	D	6	1.19×10^{-6}
1822A, B	Fails to Open	HMV (Valve) Q	2.32×10^{-3}	D	6	1.19×10^{-6}
1822A, B	Fails to Close	HMV (Valve) S	2.32×10^{-3}	D	6	1.19×10^{-6}
Pumps						
21, 22, 23	Fail to Start	HPMPM (Pump) S	6.41×10^{-3}	D	11	7.78×10^{-6}

*Hourly rates (H) are modified depending on last known good position and flow check. Demand (D) is failure to operate on demand.

TABLE 1.5.2.3.1-5

INDIAN POINT 2 SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (Inches)	System Failure	Potential for Other Systems Impact	Initiating Event	Comments
1. Line 189, Pump Suction Supply from RWST	8	Yes	Yes, Loss of RWST	No	Can be isolated by MOV 1810 to save RWST.
2. Boron Injection Tank Outlet to 1821	6	No	No	No	Can be isolated by MOV 1821.
3. Line 60, Supply from RHR System, After MOV 888A and B	8	Yes	Yes, Loss of RWST	No	Can be isolated by MOV 1810 to save RWST.
4. Pump Suction and Discharge Piping (three pumps)	6/4	No, With Operator Action	No	No	Loss of single pump train (two or three pumps will remain available after operator action).
5. Line 56, Discharge to Loops 1 and 3 Cold Legs and Loop 3 Hot Leg	6	No, With Operator Action	No	No	Loss of single discharge header (other header available after operator action).
6. Line 16, Discharge to Loops 2 and 4 Cold Legs and Loop 4 Hot Leg	6	No, With Operator Action	No	No	Loss of single discharge header (other header available after operator action).

TABLE 1.5.2.3.1-6

INDIAN POINT 2 ADDITIONAL SINGLE EVENT MINIMAL CUTSETS WHEN PUMP TRAIN 21 (OR 23) IS ISOLATED FOR MAINTENANCE

Any element in blocks C and D when train B is out for maintenance. Any element in blocks B and C when train D is out for maintenance.

TABLE 1.5.2.3.1-7

INDIAN POINT 2 ADDITIONAL SINGLE EVENT MINIMAL CUTSETS WHEN PUMP TRAIN 22 IS ISOLATED FOR MAINTENANCE

Any element in blocks B and D when train C is isolated for maintenance.

TABLE 1.5.2.3.1-8

INDIAN POINT 2 CAUSE TABLE FOR SINGLE FAILURES (BUSES 3A, 5A, 6A AVAILABLE)

Cause	Mean Unavailability	Effects			
		Components	System	Other Systems	Initiating Event
Hardware Failure	7.02×10^{-5}	Check Valve 847	Fails	No Effect	No Effect
Hardware Failure	2.64×10^{-5}	MOV 1810 (deenergized open)	Fails	No Effect	No Effect
Hardware Failure	2.64×10^{-5}	Manual Valve 846	Fails	LPIS	No Effect
Total Hardware	1.23×10^{-4}	--	--	--	--
Testing and Maintenance	0	None	No Effect	No Effect	No Effect
Human Error	None Envisioned	None	No Effect	No Effect	No Effect
Total	1.23×10^{-4}	--	--	--	--

TABLE 1.5.2.3.1-9

INDIAN POINT 2 CAUSE TABLE FOR DOUBLE FAILURES (POWER ON 3A, 5A, 6A AVAILABLE)

Cause	Mean Frequency	Effects			
		Components	System	Other Systems	Initiating Event
Coincident Pump Train Failure	1.47×10^{-4}	Mainly SI Pumps	Fails	No Effect	No Effect
Test Unavail-ability with Hardware	1.96×10^{-6}	Pump Train Valve with Pump Failure	Fails	No Effect	No Effect
Maintenance Unavailability With Hardware	4.83×10^{-5}	Maintenance on Pumps	Fails	No Effect	No Effect
Human Error	None Envisioned	None	No Effect	No Effect	No Effect
Other	9.83×10^{-5}	Pumps	Fails	No Effect	No Effect
Total	2.91×10^{-4}	--	--	--	--

NOTE: Dominant Contributor = Maintenance on SI pumps with hardware failure coincidentally.

TABLE 1.5.2.3.1-10

INDIAN POINT 2 DOMINANT CAUSE TABLE FOR HPIS
(BUSES 3A, 5A, 6A AVAILABLE)

Dominant Cause	Dominant Failure Mode	Mean Unavailability
Single Failures		
Hardware Failures	Valves Stop Flow	1.23×10^{-4}
Double Failures		
Coincident Hardware Failures	Mainly Pumps	1.47×10^{-4}
Test and Hardware	Pump Train Valve Tests	1.96×10^{-6}
Maintenance and Hardware	Pump Maintenance	4.83×10^{-5}
Other	Pump Train Common Cause	9.83×10^{-5}
Total Double Failures		2.91×10^{-4}
Total		4.14×10^{-4}

NOTE: Using DPD arithmetic we find for Q_{HPIS}:

Mean: 4.14×10^{-4}

Variance: 3.67×10^{-8}

5th Percentile: 1.97×10^{-4}

Median: 3.66×10^{-4}

95th Percentile: 8.31×10^{-4}

TABLE 1.5.2.3.1-11

INDIAN POINT 2 DOMINANT CAUSE TABLE FOR HPIS
(BUSES 3A, 5A, 6A - ANY ONE LOST)

Dominant Cause	Failure Mode	Mean Unavailability
Hardware Failure	Pump Trains	1.40×10^{-2}
Hardware Failure	Valve 1822A or 1822B and Valve 1821 or 1831	5.35×10^{-6}
Hardware Failure	Block A Suction Valves	1.23×10^{-4}
Test Unavailability of D with Bus 5A or 6A Lost	Valves Being Tested Closed in Pump Train 22	1.10×10^{-4}
Maintenance on Train Other than the Train with Lost Bus	Pump Out for Maintenance	1.15×10^{-3}
Total		1.51×10^{-2}

TABLE 1.5.2.3.1-12

INDIAN POINT 2 DOMINANT CAUSE TABLE FOR HPIS (SMALL LOCA) WITH ALL POWER BUSES AVAILABLE OR ONE BUS UNAVAILABLE

Dominant Cause	Failure Mode	Mean Unavailability
Hardware Failure	Suction Valves	1.23×10^{-4}
Hardware Failure	Remaining Pump Trains	4.90×10^{-5}
Maintenance and Hardware	Two Ways Pump Fail and Pump Maintenance Combinations	1.61×10^{-5}
Total		1.86×10^{-4}

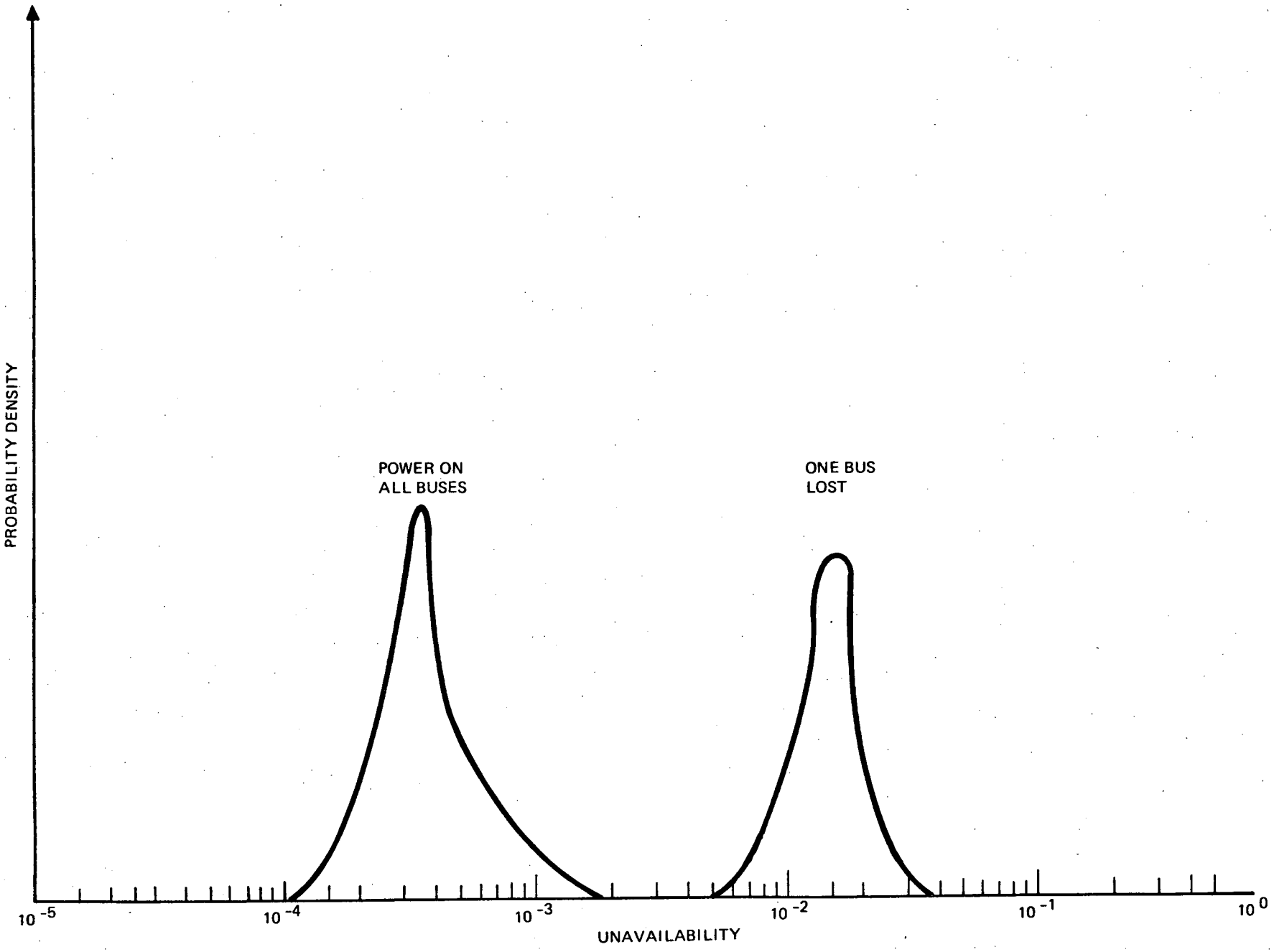


Figure 1.5.2.3.1-1. Probability Distribution of Indian Point 2 HPIS Unavailability - Medium LOCA Case

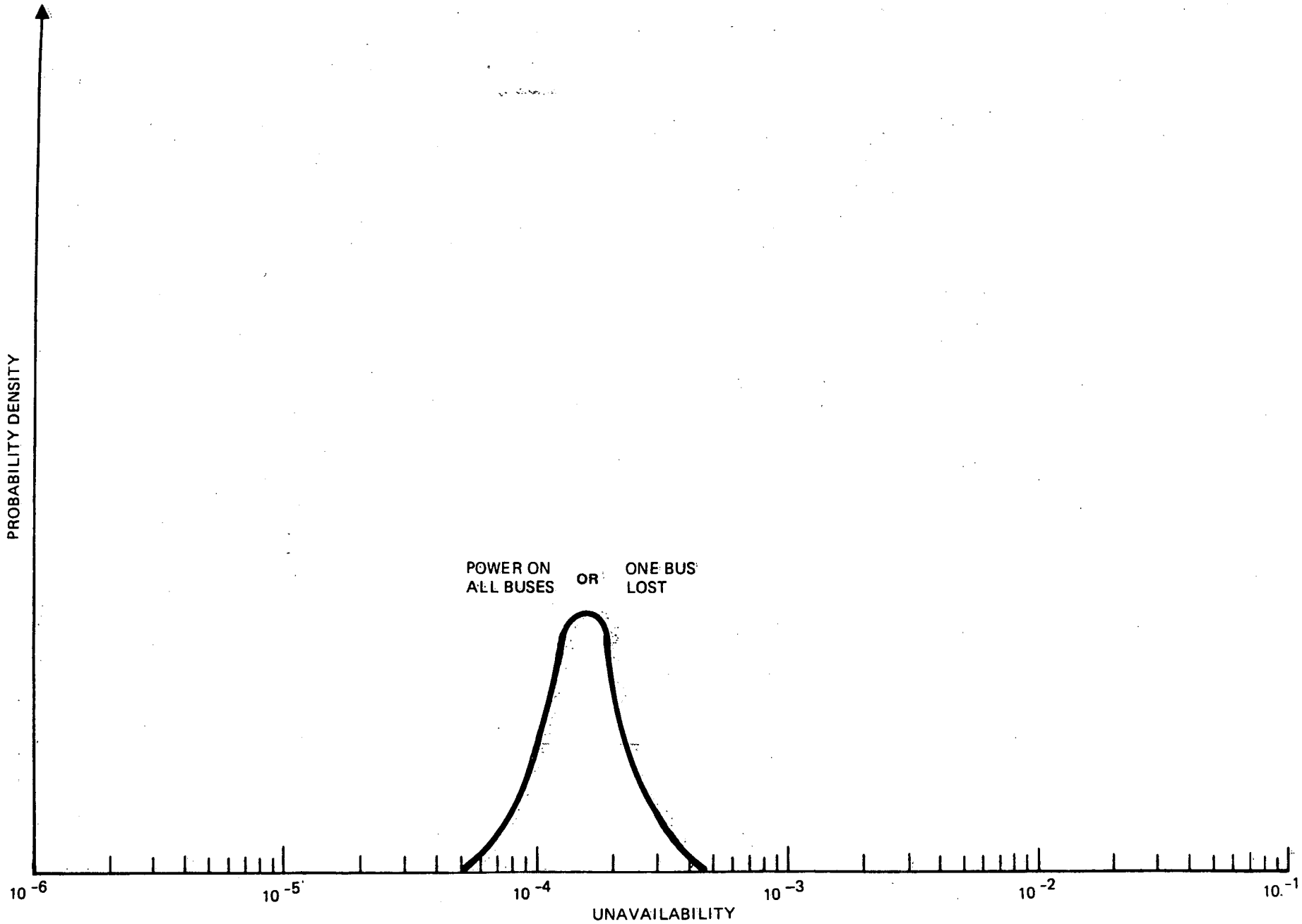


Figure 1.5.2.3.1-2. Probability Distribution of Indian Point 2 HPIS Unavailability - Small LOCA Case

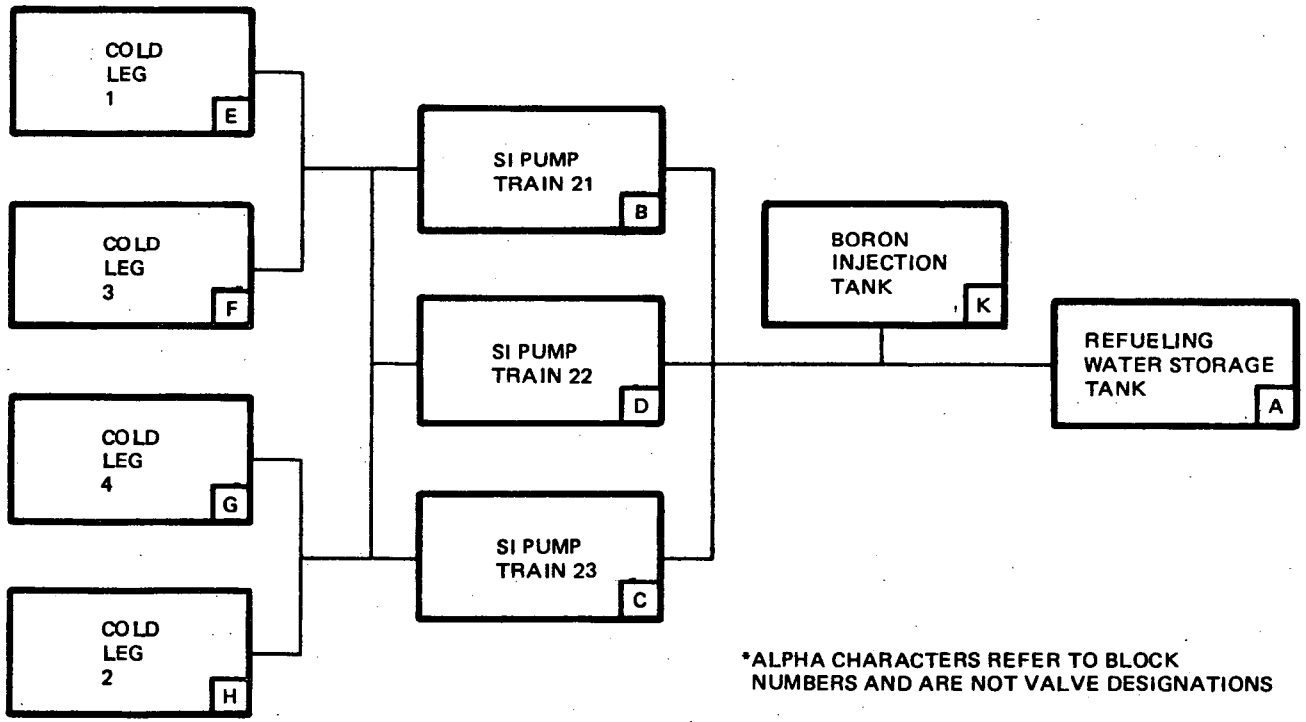


Figure 1.5.2.3.1-3. Indian Point 2 High Pressure Injection System Block Diagram

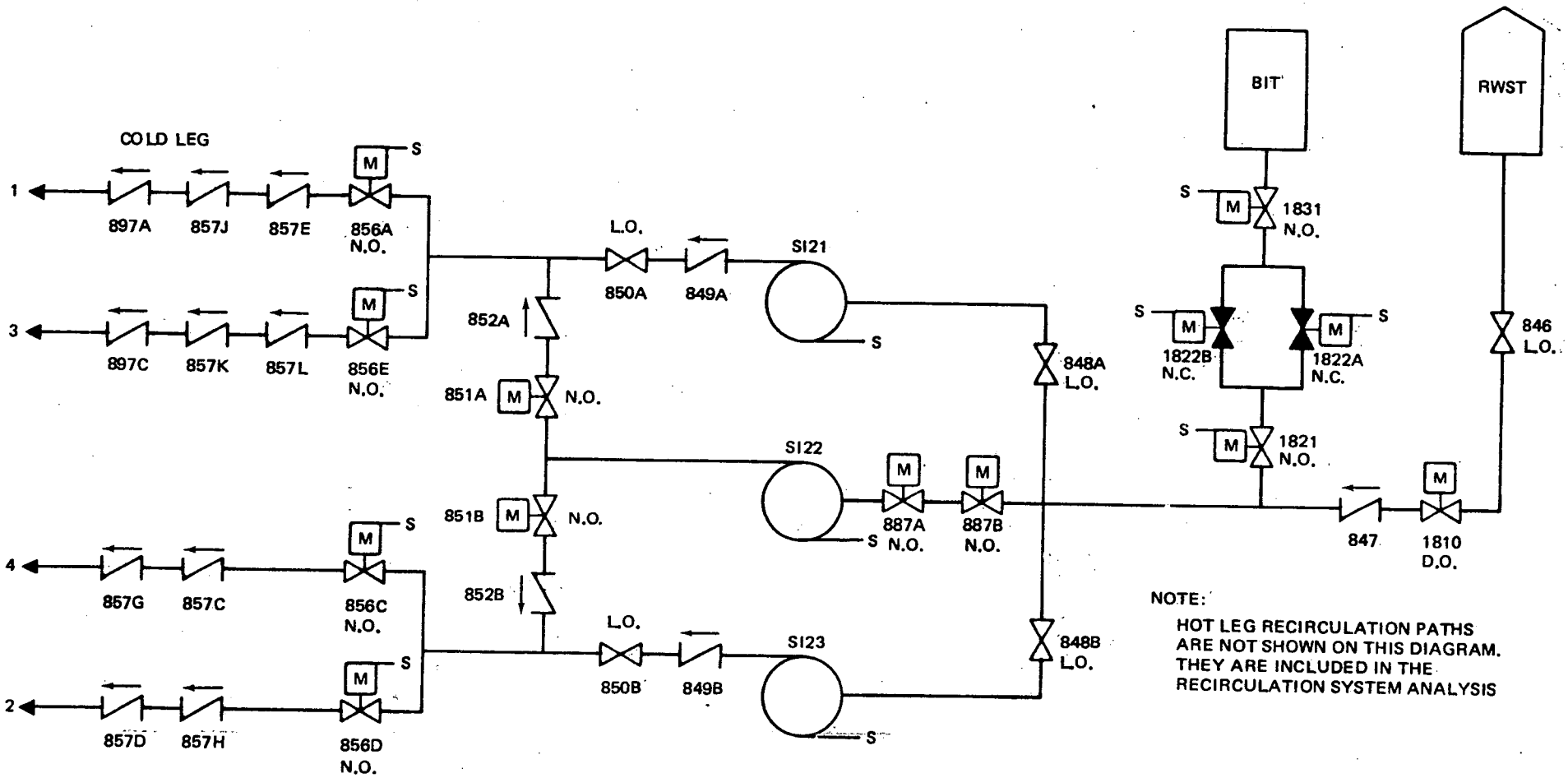


Figure 1.5.2.3.1-4. Indian Point 2 High Pressure Injection System Simplified P&ID

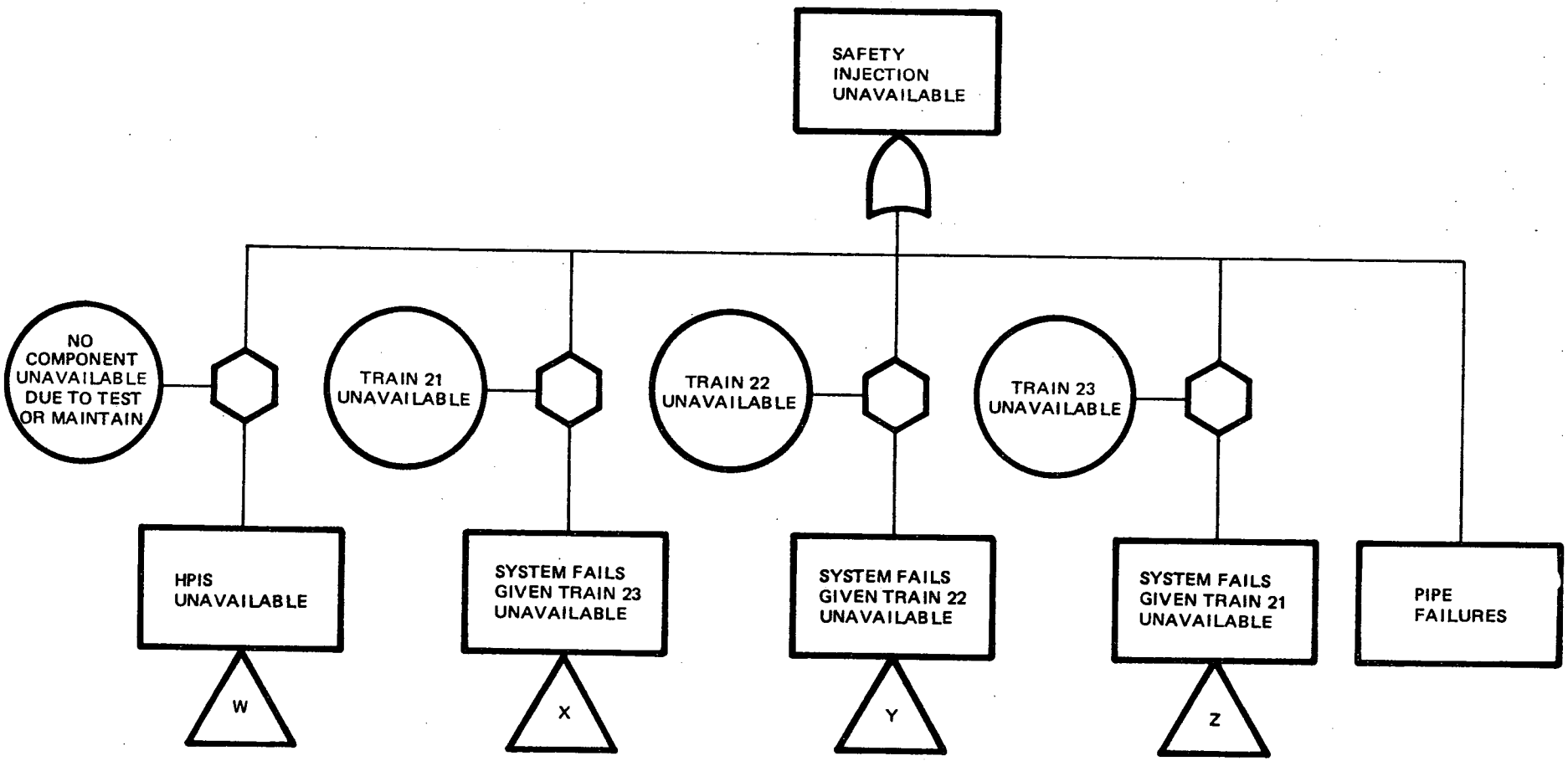
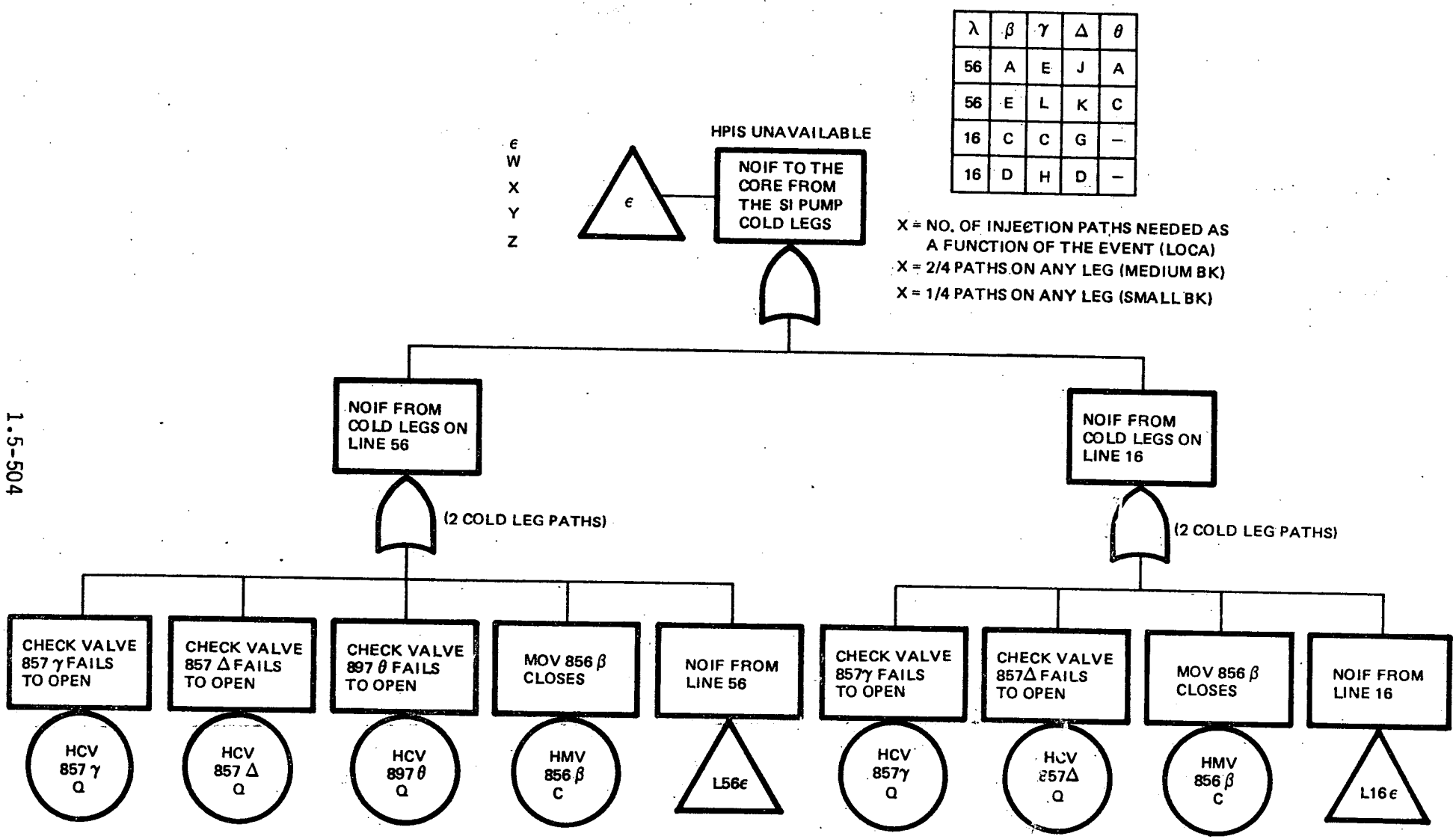
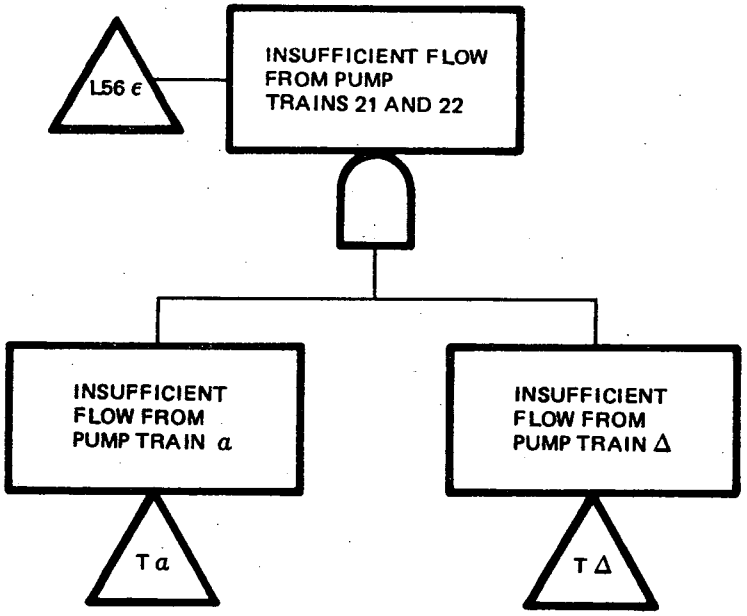


Figure 1.5.2.3.1-5. Indian Point 2 Top Structure of the Fault Tree



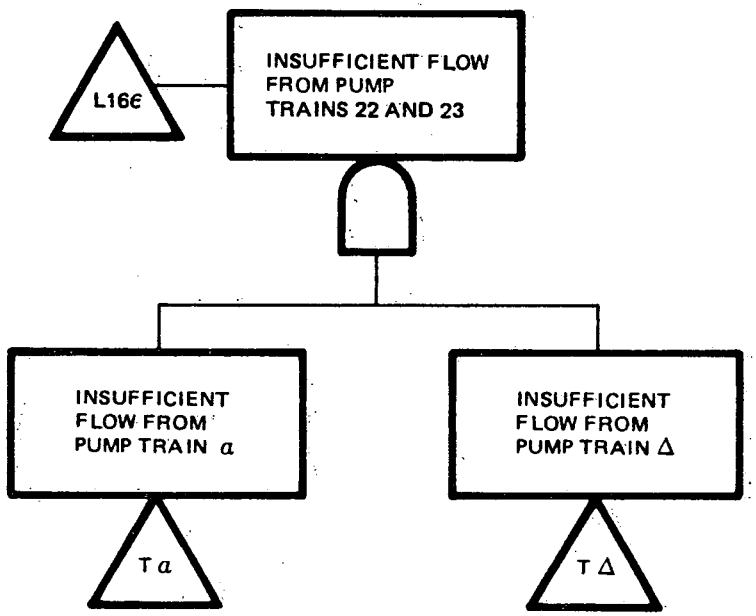
λ	β	γ	Δ	θ
56	A	E	J	A
56	E	L	K	C
16	C	C	G	–
16	D	H	D	–

Figure 1.5.2.3.1-6. Indian Point 2 High Pressure Injection System (Sheet 1 of 9)



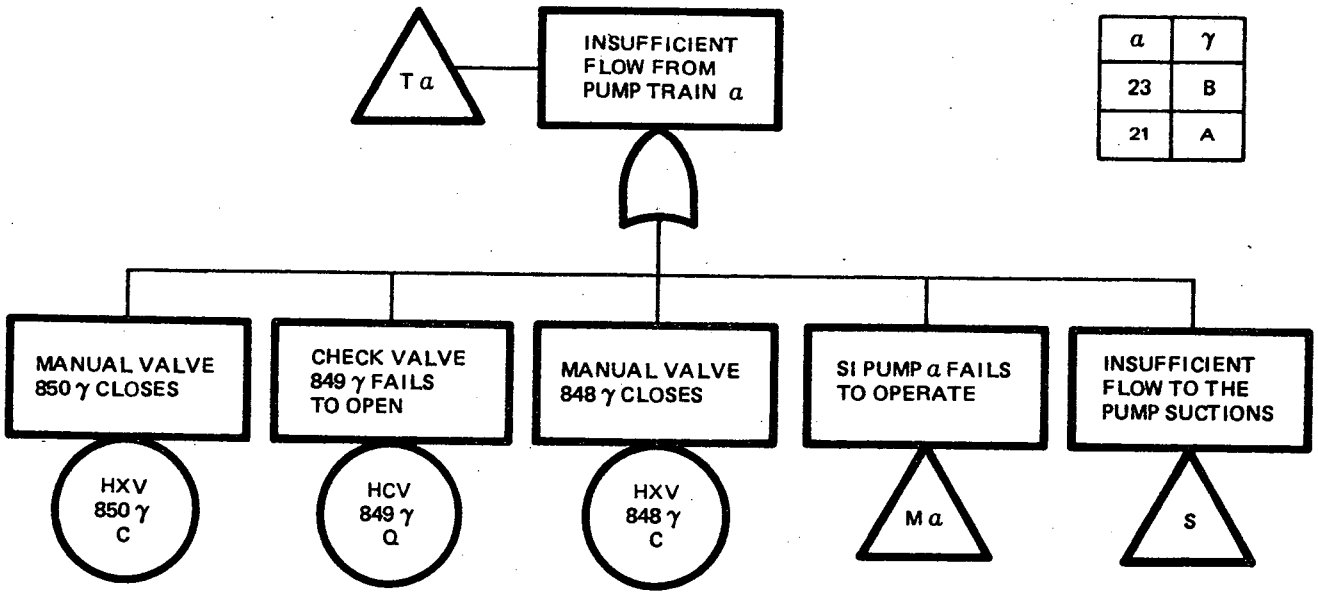
ϵ	a	Δ
W	21	22
X	21	22
Y	21	–
Z	–	22

Figure 1.5.2.3.1-6 (Sheet 2 of 9)



ϵ	a	Δ
W	23	223
X	–	223
Y	23	–
Z	23	223

Figure 1.5.2.3.1-6 (Sheet 3 of 9)



α	γ
23	B
21	A

Figure 1.5.2.3.1-6 (Sheet 4 of 9)

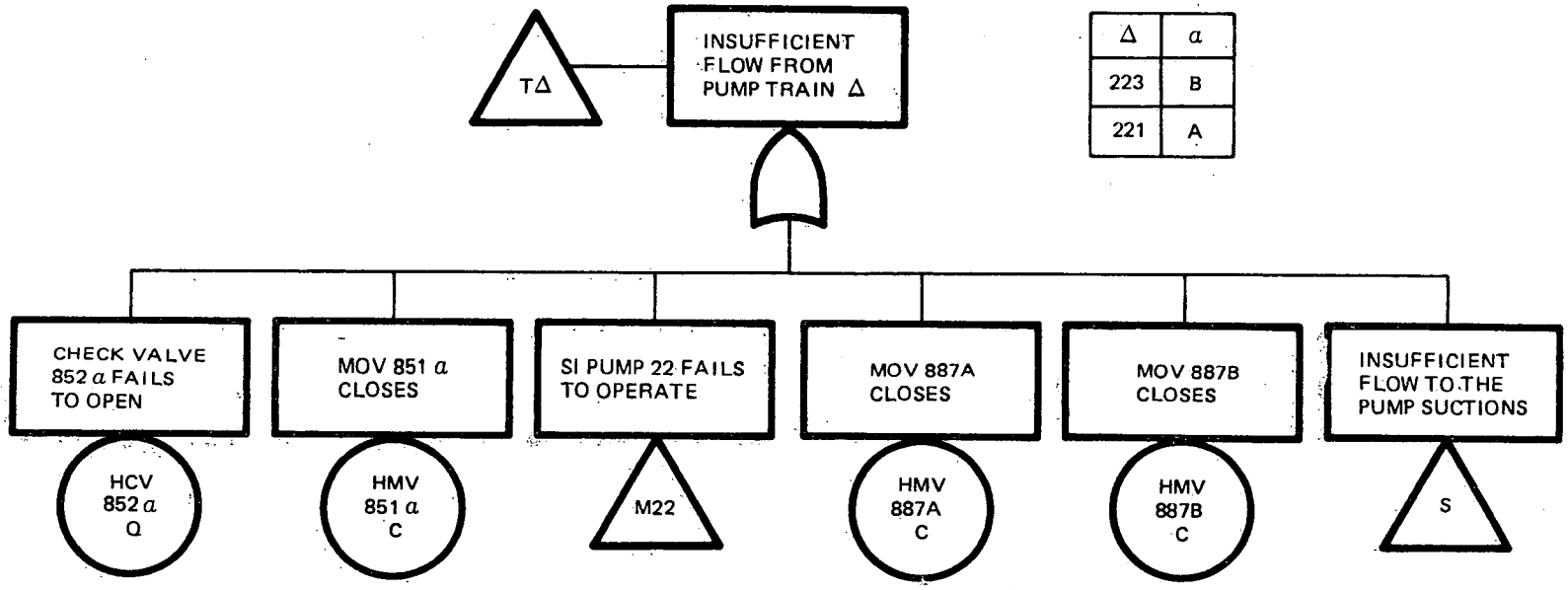
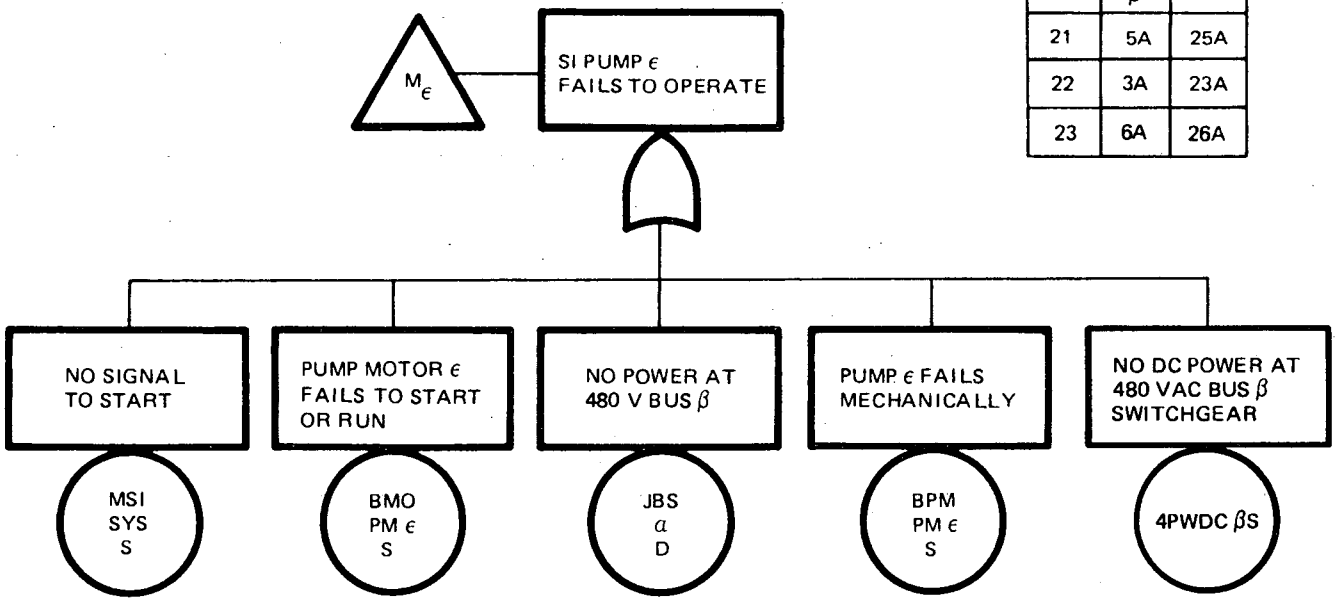


Figure 1.5.2.3.1-6 (Sheet 5 of 9)



ϵ	β	α
21	5A	25A
22	3A	23A
23	6A	26A

Figure 1.5.2.3.1-6 (Sheet 6 of 9)

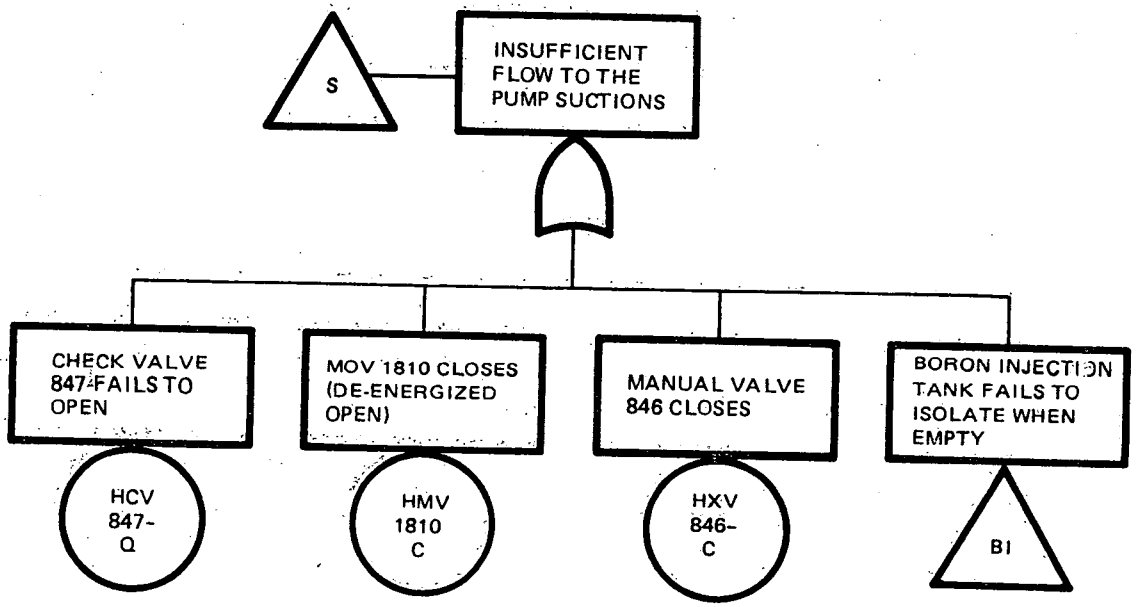


Figure 1.5.2.3.1-6 (Sheet 7 of 9)

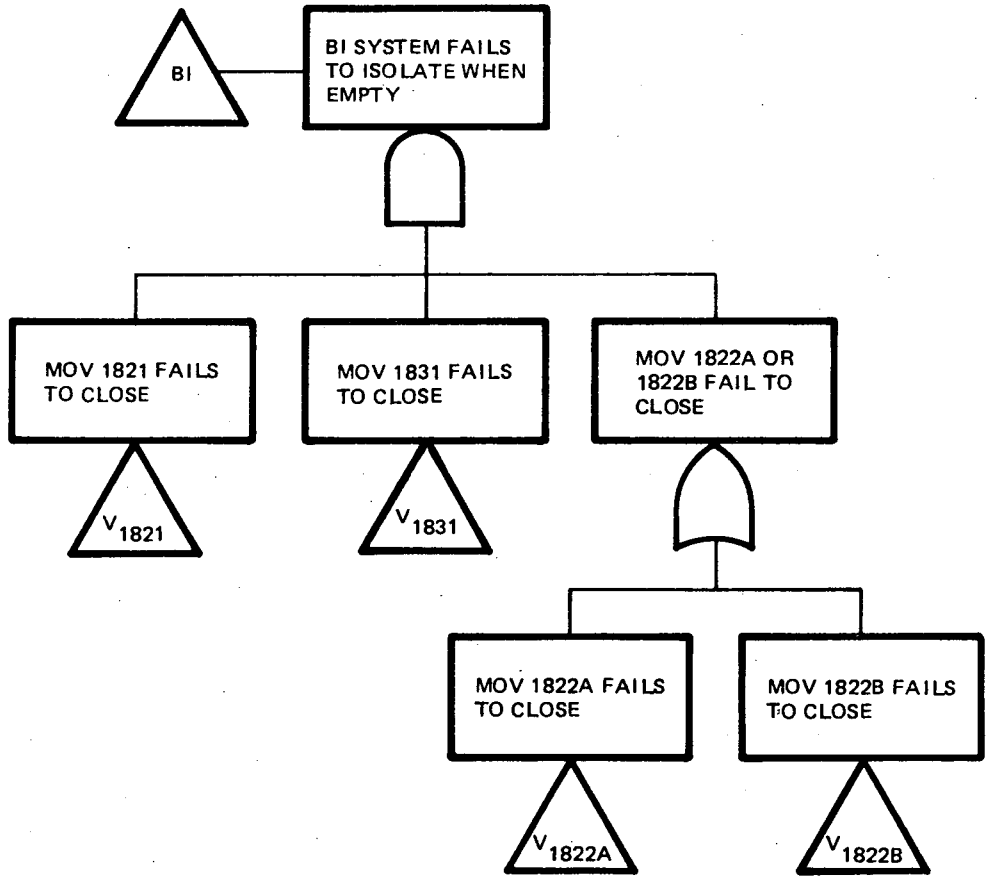
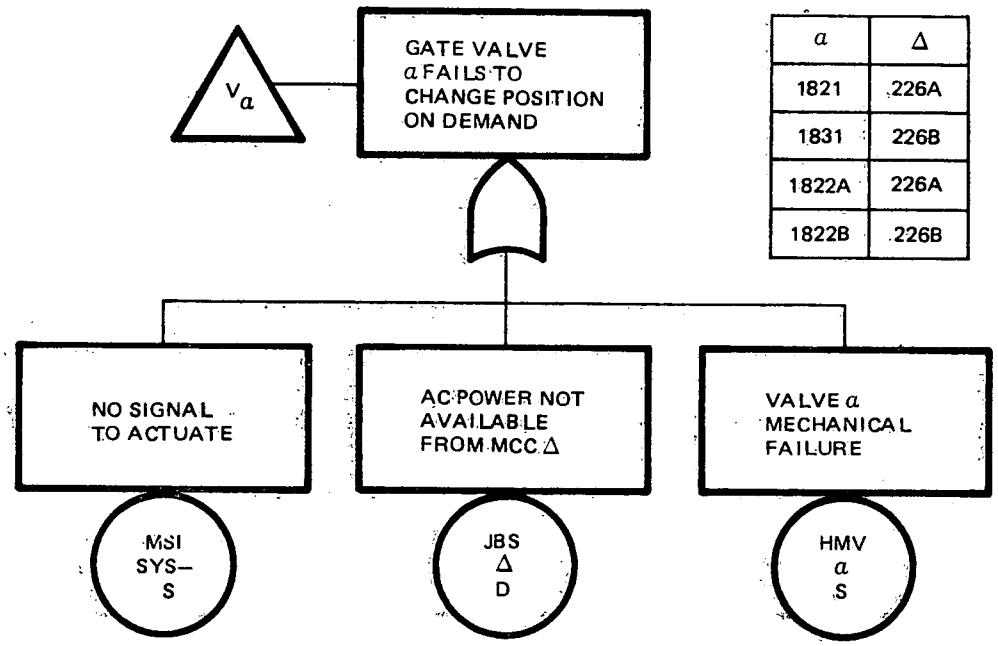


Figure 1.5.2.3.1-6 (Sheet 8 of 9)



a	Δ
1821	226A
1831	226B
1822A	226A
1822B	226B

Figure 1.5.2.3.1-6 (Sheet 9 of 9)

1.5.2.3.2 Indian Point 2 Low Pressure Injection System

1.5.2.3.2.1 Summary.

1.5.2.3.2.1.1 Introduction. The low pressure injection system (LPIS) is evaluated for a large or medium loss of coolant accident (LOCA). The system is designed to inject water into the core to replace the coolant lost from the primary system with water from the refueling water storage tank (RWST). The recirculation phase, which uses portions of the system, is analyzed separately.

The analysis is carried out under the following conditions:

- RWST is available.
- The safeguards actuation signal is present.
- Success of the system is defined as injection of water into at least two cold legs.

1.5.2.3.2.1.2 Results. Table 1.5.2.3.2-1 summarizes the results for the eight cases of electric power availability considered (combinations of buses 3A, 5A, and 6A) and lists the Reactor Safety Study (RSS) results.

The analysis demonstrated the following dominant contributors to LPIS unavailability:

	Mean
• With Electric Power Available (Buses 3A, 5A, and 6A)	8.72×10^{-4}
- Single Element Failures	6.80×10^{-4} (78.1%)
• Check valve 741	7.02×10^{-5} (08.1%)
• Check valve 881	7.02×10^{-5} (08.1%)
• Motor-operated valve 744	2.64×10^{-5} (03.0%)
• Motor-operated valve 882	4.86×10^{-4} (55.4%)
• Manual valve 846	2.64×10^{-5} (03.0%)
- Double Failures	6.91×10^{-5} (07.9%)
• Both residual heat pump pump trains 21 and 22	4.99×10^{-5} (05.7%)
• Both Motor-operated 746 and 747	6.48×10^{-6} (00.7%)
• Pump maintenance and hardware failures	1.27×10^{-5} (01.5%)
- Common Cause (Other)	1.23×10^{-4} (14.5%)
• Pumps and valves	1.23×10^{-4} (14.5%)

- Degraded Electric Power

	Mean
- Bus 3A Unavailable	8.07×10^{-3}
• Single valves block flow path	6.80×10^{-4} (08.4%)
• Pump fails to start	6.41×10^{-3} (79.4%)
• Maintenance	9.73×10^{-4} (12.1%)
- Bus 5A Unavailable	3.06×10^{-3}
• Motor-operated valves 746 and 747 fail to open	2.32×10^{-3} (75.8%)
- Bus 6A or Bus (3A and 5A) Unavailable	1.01×10^{-2}
• Pump fails to start	6.41×10^{-3} (63.5%)
• Motor-operated valves 746 and 747 fail to open	2.32×10^{-3} (23.0%)

1.5.2.3.2.1.3 Conclusions. LPIS unavailability has been calculated assuming different states of electric power. In all cases, single failures played a dominant role. Because human error was not found to be a factor, hardware failures and maintenance are the largest contributors to system unavailability. Particularly with one bus unavailable, these contributors were of the same order of magnitude to the overall system unavailability. System unavailability is summarized in the following:

Electric Power State	Mean
- All Power	8.72×10^{-4}
- 3A Unavailable	8.07×10^{-3}
- 5A Unavailable	3.06×10^{-3}
- 6A or (3A and 5A) Unavailable	1.01×10^{-2}

The probability distributions associated with each of the mean unavailabilities are displayed in Figure 1.5.2.3.2-1.

1.5.2.3.2.2 System Description.

1.5.2.3.2.2.1 System Function. For a large LOCA, the LPIS initially cools the core and replaces the coolant that is lost from the primary system with water from the RWST.

1.5.2.3.2.2.2 System Configuration. A block diagram and a simplified piping and instrumentation diagram for the system are shown in Figures 1.5.2.3.2-2 and 1.5.2.3.2-3. Success of at least one of the two residual heat removal (RHR) pump trains will provide sufficient flow to keep the core covered after a large LOCA given that two of the three intact legs (excluding the broken leg) deliver flow to the core.

1.5.2.3.2.2.3 System Operation. The pumps of this subsystem are activated by the safety injection (SI) signal. The pumps deliver 3,000 gpm each to the reactor coolant system (RCS), through the RHR heat exchangers, when the primary system pressure is approximately 150 psig. On rapid depressurization and loss of coolant, this portion of the safety injection system is designed to deliver large quantities of water to aid in rapidly recovering the core.

The RHR pumps draw water from the RWST and discharge it to the RHR heat exchangers 21 and 22 tube sides. The heat exchangers do not perform a heat transfer function during active injection, but serve the recirculation phase. The heat exchangers' discharge is then directed to the four RCS cold legs through the accumulator connection lines.

When a safety injection signal is generated, the following events will occur: If outside power or three diesels are available, both pumps start; if only two diesels are functioning, at least one pump will start. The pumps will draw water through normally open valve 882 from the RWST and discharge it through normally open valve 744. (Valves 744 and 882 are normally deenergized open.) If either valve closes, the "Safeguards Valve Off Normal Position" alarms annunciate. The flow is then to the RHR heat exchangers. Component cooling is supplied to the RHR heat exchangers, but because of the relatively low temperature of the coolant from the RWST, no actual cooling is performed by the component cooling at this time. RHR discharge valves 746 and 747 of the heat exchangers are also normally shut and receive an open signal on initiation of a safety injection signal. Hydraulic control valves 638 and 640 are normally open and annunciate the "Safeguards Valve Off Normal Position" alarm if either moves away from the normally open position.

The heat exchanger outlets join into a header and then branch off to feed the four RCS cold legs downstream of the accumulator feed lines. Flow indication is provided on the lines feeding the four loops to give the operator an indication of the system status.

1.5.2.3.2.2.4 Support Systems. The LPIS is started by a signal from the safeguards actuation system, which starts the RHR pumps. Manual actuation from the control room is also possible. Electric power is necessary for success of the system. Table 1.5.2.3.2-2 shows the power supplies to the various components of LPIS. Pump cooling is not critical because of the relatively short time involved in the injection phase and the low temperature of the water in the RWST being pumped.

1.5.2.3.2.2.5 Test Requirements. Every month pumps are started manually from the control room (test PT-M18). Table 1.5.2.3.2-3 shows the components of the system that are tested, the components tested whenever leaving cold shutdown (PT-V16), and tests performed at refueling (PT-R19).

The monthly test verifies that nine manual valves remain in normal position, six motor-operated valves remain in normal position, and three check valves open on demand. Heat exchanger 21 is also shown to pass flow with the entire system remaining in normal configuration to verify that if an SI signal is received, operation of the system will not be adversely affected. Verification of the remainder of the system is provided during cold shutdown operations.

Whenever leaving cold shutdown, eight check valves are verified seated. Any abnormal valve lineups made during this test are not critical because the system must be verified operable before startup.

At refueling, 12 check valves are verified to open on demand and then correctly reset.

1.5.2.3.2.2.6 Maintenance Requirements. Maintenance is performed as required. If a pump is found failed, it is isolated from the system for a period up to 24 hours for repair. If the repair is not completed during this period, the reactor is shut down. When one pump train is out of service, the other train is demonstrated to be operable.

1.5.2.3.2.3 Logic Model.

1.5.2.3.2.3.1 Top Events. The LPIS fault tree is developed for the event "Insufficient Flow from LPIS." This event appears in the large and medium LOCA event trees and must be preceded by a successful accumulator system operation, which is required to initiate recovery of the core.

1.5.2.3.2.3.2 System Fault Tree. Fault tree methodology is used to analyze the LPIS. The top structure of the tree shows the parts of the system that are disabled during maintenance (or testing, if applicable). Figure 1.5.2.3.2-4 shows the first level of the tree. The INHIBIT gates specify the conditions under which the tree is developed further. The fault trees for the transfers X, Y, and Z are shown in Figure 1.5.2.3.2-5. Special attention should be paid to the maintenance trees because the configuration of the system changes and the position of valves may also change. The X, Y, and Z are carried through the trees to the train gate level where the train is eliminated for the Y and Z cases.

The fault tree contains only hardware failures. For each component, the failure mode (e.g., fails open, closed, does not start, etc.) and failures to supply energy or the signals to actuate are listed. The failure causes are not listed. The fault tree is complete in that the minimal cutsets of the tree are equivalent to the top event.

1.5.2.3.2.3.3 Fault Tree Coding. Table 1.5.2.3.2-4 is a list of basic events, their failure modes, corresponding codes, and mean values.

1.5.2.3.2.3.4 Minimal Cutsets. The minimal cutsets are identified using the blocks from Figure 1.5.2.3.2-2.

The five valves in single flow lines in the LPIS represent five single event minimal cutsets. In addition, the SI signal to start can be considered a single event cutset if operator action is not included.

- Check valve 741 fails to open.
- Motor-operated valve 744 fails closed.
- Check valve 881 fails to open.
- Motor-operated valve 882 fails closed.
- Manual valve 846 fails closed.
- Simple pipe failure (see Table 1.5.2.3.2-5).

The motor-operated valves are deenergized open so that the "Failing Closed Mode" would be similar to a manual valve failing closed (i.e., the gate drops into the flow path).

The letter identified blocks from Figure 1.5.2.3.2-2 represent "blocks" that are groups of lower level components. The members of each letter block are listed below for reference in further analysis.

Block	Elements In The Block
A	Check valve 881, MOV 882, manual valve 846.
A'	MOV 885A, MOV 885B. This double failure would allow water to go into the sump, causing an earlier start of recirculation, but the water would not be lost.
B	Manual valves 735B, 739B, check valve 738B, RHR pump 21. The double failures involving excessive leakage back through check valve 886A or 886B and MOV 1802A or 1802B transferring open were found to be of low probability and were not included in the major contributors (on the order of 10^{-13}).
C	Manual valves 735A, 739A, check valve 738A, RHR pump 22. The double failures involving excessive leakage back through check valve 886A or 886B and MOV 1802A or 1802B transferring open were found to be of low probability and were not included in the major contributors (on the order of 10^{-13}).
D	MOV 744, check valve 741. Because the monthly test of the RHR pumps does not use the line containing valves 883 and 1863, they are validated closed monthly and the probability of both opening at the time of a safety injection was considered small.
E	Manual valve 742, heat exchanger 21, MOV 889B, MOV 747, HCV 638. Flow through MOVs 888A and 888B would not be lost as it would follow a different path into the core. Therefore, these valves were not included as failures. MOVs 889A and 889B are not considered single failures because the flow will split between the spray line and the injection headers on the path where the 889 valve is open. The other path would have a nearly normal head if both pumps are running. In addition, if the contaiment spray pumps are running, they provide 300 psi head which would cause flow into the LPIS path.

Block	Elements In The Block
F	MOV 745B, MOV 745A, heat exchanger 22, MOV 889A, MOV 746, HCV 640. Flow through MOVs 888A and 888B would not be lost because it would follow a different path into the core. Therefore, these valves were not included as failures. MOVs 889A and 889B are not considered single failures because the flow will split between the spray line and the injection headers on the path which has the 889 valve open. The other path would run nearly normal head if both pumps are running. In addition, if the containment spray pumps are running, they provide 300 psi head which would cause flow into the LPIS path.
G	Check valves 897A, 838A.
H	Check valves 897B, 838B.
I	Check valves 897C, 838C.
J	Check valves 897D, 838D.

Likewise, the check valves 738A or 738B having excessive leakage and the pump not starting on that path were found to be of low probability and were not included in the major contributors (on the order of 10^{-8}).

Using these letter blocks, double failures can be determined by the following combinations; (B and C), A', (E and F) and, depending on which cold leg has had the large LOCA, combinations of G, H, I, and J as follows:

LOCA Leg	Double Failures
1	HI, IJ, JH
2	GI, IJ, JG
3	GH, HJ, JG
4	GH, HI, IG

Because the probability of the LOCA occurring on any one of the legs is equal, each of these double failures is equally probable. There are no three-element or higher order failures in this LPIS.

Tables 1.5.2.3.2-6 and 1.5.2.3.2-7 show the additional single-element cutsets under maintenance conditions.

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1.5.2.3.2.4 Quantification: Boundary Condition, Electric Power Available On Buses 3A, 5A, AND 6A.

1.5.2.3.2.4.1 Quantification of Single Failures.

1.5.2.3.2.4.1.1 Hardware contribution. Each single event minimal cutset is analyzed using plant specific data:

- Check valve 741 fails to open on demand. The mean and variance are:

  $Mean_{CV1}$: 7.02×10^{-5}

  $Variance_{CV1}$: 1.09×10^{-8}

- Motor-operated valve 744 fails closed (deenergized open).

  $Mean_{MOV,C1}$: $7.40 \times 10^{-8}/\text{hour} \times 24\ \text{hour/day} \times \frac{\text{30-day test cycle}}{2}$

  $= 2.64 \times 10^{-5}$

  $Variance_{MOV,C1}$: $5.89 \times 10^{-15} \times (24 \times 15)^2 = 7.57 \times 10^{-10}$

- Check valve 881 fails to open on demand.

  $Mean_{CV2}$: 7.02×10^{-5}

  $Variance_{CV2}$: 1.09×10^{-8}

- Motor-operated valve 882 fails closed (deenergized open).

  $Mean_{MOV,C}$: $7.40 \times 10^{-8}/\text{hour} \times \frac{\text{13,140 hour test cycle}}{2} = 4.86 \times 10^{-4}$

  $Variance_{MOV,C}$: $5.89 \times 10^{-15} \times \left(\frac{13{,}140}{2}\right)^2 = 5.08 \times 10^{-7}$

- Manual valve 846 fails closed (locked open).

  $Mean_{MV,C}$: $7.40 \times 10^{-8}/\text{hour} \times \frac{\text{30 day test cycle}}{2} \times \frac{\text{24 hours}}{\text{day}} = 2.64 \times 10^{-5}$

  $Variance_{MV,C}$: $5.89 \times 10^{-15} \times \left(\frac{30 \times 24}{2}\right)^2 = 7.57 \times 10^{-10}$

- Pipe failure. Table 1.5.2.3.2-5 shows the pipe sections that constitute single failures of the LPIS. Pipe failure does not contribute significantly to LPIS unavailability.

  The total hardware contribution for single failures is the addition of the components A and D using discrete probability distribution (DPD arithmetic).

$$\text{Mean}_{\text{singles}}: \quad 2\ \text{Mean}_{CV} + \text{Mean}_{MOV,C1} + \text{Mean}_{MOV,C} + \text{Mean}_{MV,C}$$

$$= 2 \times 7.02 \times 10^{-5} + 2 \times 2.64 \times 10^{-5} + 4.86 \times 10^{-4}$$

$$= 6.80 \times 10^{-4}$$

$$\text{Variance}_{\text{singles}}: \quad 5.52 \times 10^{-7}$$

1.5.2.3.2.4.1.2 Test and maintenance contribution. The normal configuration of the system is retained during the monthly test (PT-M18), with no valves being stroked during the test. Therefore, the flow paths up to valve 638 are verified open. All other tests are performed at refueling or leaving cold shutdown (PT-R19 and PT-V16). Abnormal valve lineups made during these tests will be noted because the flow tests are required before startup. This ensures that there will be no unavailability contribution of the system due to testing.

Valve maintenance is not performed during operation on any of the single cutset valves if it must be removed or changed from normal operating position. In that case, the plant is shut down.

Therefore, for these single element failures, there is no contribution to unavailability of the system.

1.5.2.3.2.4.1.3. Human error contribution. LPIS receives automatic safety injection signals at all valves and pumps that require a change of state on injection. No human interaction is required until the recirculation phase.

Table 1.5.2.3.2-8 presents the contribution of single failures to system unavailability.

1.5.2.3.2.4.2 Quantification of Double Failures.

1.5.2.3.2.4.2.1 Hardware contribution. All remaining hardware failure contribution comes from two-element cutsets as described in Section 1.5.2.3.2.3. Each block is examined to determine the magnitude of its contribution to unavailability.

- Block B (or C) Pump Train Section

	Subscript	Unavailability	
		Mean	Variance
RHR pump (fails to start)	P	6.41×10^{-3}	7.78×10^{-6}
Check valve (fails to open)	CV	7.02×10^{-5}	1.09×10^{-8}
Manual valves (transfer closed)	MV	2.64×10^{-5}	7.57×10^{-10}

The mean of B or C is then:

$$\text{Mean}_B: \quad \text{Mean}_P + \text{Mean}_{CV} + 2\text{Mean}_{MV} = 6.5 \times 10^{-3}$$

$$\text{Variance}_B: \quad 7.9 \times 10^{-6}$$

The double failure BC using DPD is:

$$\text{Mean}_{BC}: \quad \left(\text{Mean}_B\right)^2 = \left(6.5 \times 10^{-3}\right)^2 = 4.99 \times 10^{-5}$$

$$\text{Variance}_{BC}: \quad 2.37 \times 10^{-9}$$

- Block E (or F) Heat Exchanger Path Section

	Subscript	Unavailability	
		Mean	Variance
Motor valve 747 (746) (fails to open)	MOV1	2.32×10^{-3}	1.19×10^{-6}
Motor valve 638 (640) (transfers closed)	MOV2	8.74×10^{-5}	8.21×10^{-9}
Motor valve 889A, B (transfers open)	MOV3	7.13×10^{-6}	3.40×10^{-8}
Heat exchanger 21 (22) (plugged)	HX	ε	

Which implies:

$$\text{Mean}_{MOV2} = 7.4 \times 10^{-8}/\text{hour} \times 24 \text{ hours/day} \times 365 \text{ days/year}$$

$$\times\ 1 \text{ year}/3.7 \text{ cold shutdowns} \times 1/2$$

$$\text{Mean}_{MOV3} = 1.99 \times 10^{-8}/\text{hour} \times 24 \text{ hours/day} \times 15 \text{ days}$$

- Block E (or F) Heat Exchanger Path Section (continued)

	Subscript	Unavailability	
		Mean	Variance
Manual valve 742 (train 21) (transfers closed) (see calculations for MOV 744)	MV	2.64×10^{-5}	7.57×10^{-10}
Two MOVs 745A, B (train 22) (transfer closed) each (see calculations for MOV 638)	MOV4	8.74×10^{-5}	8.21×10^{-9}

This tabulation summarizes the contributors for blocks E and F. The elements for block E include all the elements except the two MOVs (745A, B). Block F includes all the elements except the single manual valve (742). The unavailability of the blocks is computed and used to compute the system unavailability.

Examination of the mean unavailability contribution listed shows that the MOV1 is dominant by a factor of 10^2. Therefore, the double failure of E and F is evaluated using DPD:

$$\text{Mean}_{EF}: \quad \text{Mean}_E^2 = \left(2.32 \times 10^{-3}\right)^2 = 6.48 \times 10^{-6}$$

$$\text{Variance}_{EF}: \quad 5.27 \times 10^{-11}$$

The remaining two event cutsets of the check valves in the cold legs are very insignificant as shown by

$$\text{Mean}_{CV_2}: \quad \text{Mean}_{CV}^2 = \left(7.02 \times 10^{-5}\right)^2 = 1.51 \times 10^{-8}$$

Even with many such cutsets, the contribution to system hardware unavailability is still dominated by the single event cutsets and the two event cutsets of both pumps failing to start and both MOVs (746, 747) failing to open.

1.5.2.3.2.4.2.2 Test contribution. As developed in Section 1.5.2.3.2.4.1.2, testing does not adversely affect the system; therefore, there is no contribution to system unavailability from testing.

1.5.2.3.2.4.2.3 Maintenance contribution. As discussed in Section 1.5.2.3.2.4.1.2, valve maintenance is not considered here. However, RHR pump maintenance is a contributor to system unavailability.

RHR pump 22 shows three instances of being down for maintenance with the reactor not in cold shutdown. The total operating hours from 1977 to 1980 corresponding to these instances yield a pump unavailability due to maintenance of:

Mean: 9.73×10^{-4}

Variance: 7.95×10^{-8}

The system fails when B is under maintenance and C also fails, yielding:

Mean: $9.73 \times 10^{-4} \times 6.50 \times 10^{-3} = 6.32 \times 10^{-6}$

Variance: 1.43×10^{-11}

Likewise, when C is under maintenance and B fails, the result is the same. Therefore, the total contribution is:

Mean: $2 \times 6.32 \times 10^{-6} = 1.27 \times 10^{-5}$

Variance: 9.60×10^{-11}

1.5.2.3.2.4.2.4 Human error contribution. From the discussion of the tests in Section 1.5.2.3.2.4.1.2, the flow tests after maintenance at refueling or cold shutdown ensure that valves are aligned correctly. The monthly tests do not change valve position. After pump maintenance, the pump isolation valves are verified open by a flow test of the repaired pump train. Therefore, no human error due to these maintenance procedures is included.

1.5.2.3.2.4.2.5 Other causes. Most of the observed coupled failures in the industry involved motor-operated or air-operated valves that had to change position on demand. The frequent partial and full system tests indicate that an unforeseen common cause failure is of low frequency. This state of knowledge is expressed by taking a β-factor with range 1×10^{-3} to 5×10^{-2} which yields a mean and variance of:

Mean β : 1.4×10^{-2}

Variance β: 6.1×10^{-4}

This β-factor is assessed for the common cause failure of blocks BC and EF; therefore, the contribution to system unavailability is

Mean: $1.4 \times 10^{-2} \times (6.5 \times 10^{-3} + 2.32 \times 10^{-3}) = 1.23 \times 10^{-4}$

1.5.2.3.2.4.2.6 Double failure contribution. Table 1.5.2.3.2-9 summarizes the double failure contributions.

1.5.2.3.2.4.3 No Triple Failures.

1.5.2.3.2.4.4 System Unavailability. Table 1.5.2.3.2-10 shows the results derived for the mean values of the dominant contributors to LPIS unavailability. These contributors are the basis for the uncertainty analysis. The mathematical expression for the unavailability of the system in terms of the unavailabilities of the dominant contributors is

$$Q_{LPIS} = 2Q_{CV} + Q_{MOV2}\left[2\left(\frac{24 \times 30}{2}\right) + \frac{13{,}140}{2}\right] + Q^2_{Pump} + Q^2_{MOV1} + 2Q_{Maintenance}\, Q_{Pump} + B(Q_{Pump} + Q_{MOV1})$$

Using DPD arithmetic Q_{LPIS} is:

Mean:	8.7×10^{-4}
Variance:	3.2×10^{-7}
5th Percentile:	2.8×10^{-4}
Median:	7.1×10^{-4}
95th Percentile:	2.0×10^{-3}

1.5.2.3.2.5 Quantification: Boundary Condition, Degraded Electric Power. When any of buses 3A, 5A, or 6A are not available, an RHR train or a heat exchanger flow path may become unavailable. This causes the elements in the remaining path to become single element cutsets. Blocks B(C) and E(F) are then added directly to the other single event cutsets to calculate the unavailability with one bus out. Referring to Figure 1.5.2.3.2-3, the number of valves of each type must be determined because the data structure leads to dependence among valves from the same generic data base.

- Manual (MOVs that do not operate) = 8 or 7
- Check Valves = 3
- Pump = 1
- MOV (changes position) = 1

The calculation still demonstrates that the pump and MOV that must change position dominate the other single elements in the flow path.

If a bus is unavailable and maintenance is being performed, the system would be unavailable. These results are shown in Table 1.5.2.3.2-11.

TABLE 1.5.2.3.2-1A

INDIAN POINT 2 LPIS UNAVAILABLE - ELECTRIC POWER AVAILABLE

Bus Condition	Mean	Variance	5th Percentile	Median	95th Percentile
RSS Comparison	Not Given	Not Given	3.1×10^{-4}	4.7×10^{-3}	7.4×10^{-3}
Buses 3A, 5A, and 6A Available	8.7×10^{-4}	3.2×10^{-7}	2.8×10^{-4}	2.1×10^{-4}	2.0×10^{-3}

TABLE 1.5.2.3.2-1B

INDIAN POINT 2 LPIS UNAVAILABLE - ONE OR MORE ELECTRIC BUSES

	Buses Unavailable(1)						
	3A	5A	6A	3A and 5A	3A and 6A	5A and 6A	3A, 5A, and 6A
System Unavailibility (Mean)	8.07×10^{-3}	3.06×10^{-3}	1.01×10^{-2}	1.01×10^{-2}	1.0	1.0	1.0

(1) Bus 2A does not have any impact on this system.

TABLE 1.5.2.3.2-2

INDIAN POINT 2 LPIS POWER SUPPLIES

Component	Power Supply
RHR Pump 21	Bus 3A
RHR Pump 22	Bus 6A
MOV747	Bus 6A/ MCC-26B
MOV746	Bus 5A/ MCC-26A

TABLE 1.5.2.3.2-3

INDIAN POINT 2 TESTING REQUIREMENTS

Component	Testing/Inspection
RHR Pump 21	Started and stopped monthly when leaving cold shutdown and at refueling.
RHR Pump 22	Started and stopped monthly when leaving cold shutdown and at refueling.
MOV822	Verify open, refueling.
MOV744	Verify open; monthly.
MOV889B; 885A or B; 888A,B; 883	Verify closed; monthly. Stroked quarterly (except for 883).
Manual Valves 735A,B; 739A,B; 846*	Verify open; monthly.
Check Valve 881	Open on demand; refueling.
Check Valves 738A,B; 741	Open on demand; monthly. Leak test (741 only) refueling.
Check Valves 897A-D, 838A-D	Seated correctly; leaving cold shutdown. Open on demand; cold shutdown.
MOV 745A,B, 638, 640	Stroked quarterly. Verify open at cold shutdowns.
MOV 889A	Stroked quarterly. Verify closed at cold shutdowns.
MOV 746, 747	Stroked at cold shutdown. Verify open at cold shutdown.

*As part of high pressure injection system monthly test.

TABLE 1.5.2.3.2-4

INDIAN POINT 2 LIST OF COMPONENTS

Component	Failure Mode	Fault Tree Coding	Mean Failure Rate	H/D	Variance	Reference
Check Valves						
897(A,B,C,D)	Fails to open	BCV897(A,B,C,D)Q	7.02×10^{-5}	D	1.09×10^{-8}	3
838(A,B,C,D)	Fails to open	BCV838(A,B,C,D)Q	7.02×10^{-5}	D	1.09×10^{-8}	3
881	Fails to open	BCV881-Q	7.02×10^{-5}	D	1.09×10^{-8}	3
738(A,B)	Fails to open	BCV738(A,B)Q	7.02×10^{-5}	D	1.09×10^{-8}	3
741	Fails to open	BCV741-Q	7.02×10^{-5}	D	1.09×10^{-8}	3
Manual Valves						
742	Transfers closed	BXV742-C	7.40×10^{-8}	H	5.89×10^{-15}	1
739(A,B)	Transfers closed	BXV739(A,B)C	7.40×10^{-8}	H	5.89×10^{-15}	1
735(A,B)	Transfers closed	BXV735(A,B)C	7.40×10^{-8}	H	5.89×10^{-15}	1
846	Transfers closed	BXV846-C	7.40×10^{-8}	H	5.89×10^{-15}	1
Motor Operated Valves						
638 (butterfly)	Transfers closed	BMV638-C (butterfly)	7.40×10^{-8}	H	5.89×10^{-15}	1
640 (butterfly)	Transfers closed	BMV640-C (butterfly)	7.40×10^{-8}	H	5.89×10^{-15}	1
745(A,B)	Transfers closed	BMV745(A,B)C	7.40×10^{-8}	H	5.89×10^{-15}	1
744	Transfers closed	BMV744-C	7.40×10^{-8}	H	5.89×10^{-15}	1
882	Transfers closed	BMV882-C	7.40×10^{-8}	H	5.89×10^{-15}	1
885(A,B)	Transfers open	BMV885(A,B)B	1.99×10^{-8}	H	1.83×10^{-13}	2
746	Fails to open	BMV746-Q	2.32×10^{-3}	D	1.19×10^{-6}	6
747	Fails to open	BMV747-Q	2.32×10^{-3}	D	1.19×10^{-6}	6
889(A,B)	Transfers open	BMV889(A,B)B	1.99×10^{-8}	H	1.83×10^{-13}	2

TABLE 1.5.2.3.2-4 (continued)

INDIAN POINT 2 LIST OF COMPONENTS

Component	Failure Mode	Fault Tree Coding	Mean Failure Rate	H/D	Variance	Reference
Heat Exchangers						
21	Plugged	BHEHE21L	*	H	*	25, 26
22	Plugged	BHEHE22L	*	H	*	25, 26
Pumps (RHR)						
21	Loss of function	BPMPM21S	6.41×10^{-3}	D	7.78×10^{-6}	11
22	Loss of function	BPMPM22S	6.41×10^{-3}	D	7.78×10^{-6}	11
Pump Motors						
21	Loss of function	BMOPM21S	Combined with pump failure			
22	Loss of function	BMOPM22S	Combined with pump failure			

*Very small and insignificant compared to other components.

TABLE 1.5.2.3.2-5

INDIAN POINT 2 SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section Nuclear Header	Diameter (inches)	System Failure	Potential for Other Systems Impact	Initiating Event	Comments
1. Line 155, supply to RHR pumps from RWST	12	Yes	Yes, loss of RWST	No	Can be isolated manually (valve 846)
2. Line 57, supply to RHR pumps from containment sump (after MOV885B)	18	Yes	Loss of pump suction (and RWST)	No	Can be isolated manually (valve 846)
3. Pump suction and discharge piping (two pumps)	14/18	Yes	Loss of RWST	No	Individual pump can be isolated manually
4. Line 9, pump discharge to RHR heat exchangers	12	Yes	Loss of RWST	No	Can be isolated
5. Outlet RHR heat exchangers	8	Yes	Loss of RWST	No	
6. Line 361 combined heat exchanger outlet	10	Yes	No	No	
7. Individual loop injection lines (after flow restricting orifice) (H)	6	No	Yes, possible loss of associated accumulator	No	See accumulator piping table

TABLE 1.5.2.3.2-6

INDIAN POINT 2 ADDITIONAL SINGLE EVENT MINIMAL CUTSETS WITH PUMP TRAIN 21 DISABLED DUE TO MAINTENANCE

BPMPM21S:	RHR Pump 21 Mechanical
BMOPM21S:	RHR Pump 21 Motor
BXV739BC:	Manual Valve 739B
BXV735BC:	Manual Valve 735B
BCV738BQ:	Check Valve 738B

See Table 1.5.2.3.2-4 for Component Codes

TABLE 1.5.2.3.2-7

INDIAN POINT 2 ADDITIONAL SINGLE EVENT MINIMAL CUTSETS WITH PUMP TRAIN 22 DISABLED DUE TO MAINTENANCE

BPMPM22S:	RHR Pump 22 Mechanical
BMOPM22S:	RHR Pump 22 Motor
BXV739AC:	Manual Valve 739A
BXV735AC:	Manual Valve 735A
BCV738AC:	Check Valve 738A

See Table 1.5.2.3.2-4 for Component Codes.

TABLE 1.5.2.3.2-8

INDIAN POINT 2 CAUSE TABLE FOR SINGLE FAILURES - BUSES 3A, 5A, AND 6A AVAILABLE

Cause	Mean Unavailability	Effects			
		Components	System	Other Systems	Initiating Event
Hardware Failure	7.02×10^{-5}	CV741 Fails to Open	Fails	Not Affected	No Effect
Hardware Failure	7.02×10^{-5}	CV881 Fails to Open	Fails	Not Affected	No Effect
Hardware Failure	2.64×10^{-5}	MOV744 Closes (deenergized open)	Fails	Not Affected	No Effect
Hardware Failure	4.86×10^{-4}	MOV882 Closes (deenergized open)	Fails	Not Affected	No Effect
Hardware Failure	2.64×10^{-5}	Manual Valve 846 Closes (locked open)	Fails	High Pressure Safety Injection	No Effect
Total Hardware	6.80×10^{-4}				
Testing and Maintenance	0	None	No Effect	No Effect	No Effect
Human Error	0	None	No Effect	No Effect	No Effect
TOTAL	6.80×10^{-4}				

Dominant contributor = hardware failures.

TABLE 1.5.2.3.2-9

INDIAN POINT 2 CAUSE TABLE FOR DOUBLE FAILURES - BUSES 3A, 5A, AND 6A AVAILABLE

Cause	Mean Frequency		Effects		
		Components	System	Other Systems	Initiating Event
Coincident Hardware Failures	4.99×10^{-5}	Mainly RHR Pumps	Fails	No Effect	No Effect
Coincident Hardware Failures	6.48×10^{-6}	Mainly MOV746, 747	Fails	No Effect	No Effect
Maintenance and Hardware Failures	1.27×10^{-5}	RHR Pump Maintenance	Fails	No Effect	No Effect
Human Error and Hardware Failures	None Envisioned	No Effect	No Effect	No Effect	No Effect
Other	1.23×10^{-4}	Pumps and MOVs	Fails	No Effect	No Effect
TOTAL	1.92×10^{-4}				

Dominant contributor = nearly equivalent contributions.

TABLE 1.5.2.3.2-10

INDIAN POINT 2 DOMINANT CONTRIBUTOR - CAUSE TABLE FOR LPIS BUSES 3A, 5A, AND 6A AVAILABLE

Dominant Cause	Failure Mode	Mean Unavailability
Single Failures Hardware Failures	Valves Stop Flow	6.80×10^{-4}
Double Failures Coincident Hardware Failures		5.64×10^{-5}
Maintenance	Pump Unavailable	1.27×10^{-5}
Other	Pumps and MOVs	1.23×10^{-4}
TOTAL		8.72×10^{-4}

TABLE 1.5.2.3.2-11

INDIAN POINT 2 DOMINANT CAUSE FOR LPIS (DEGRADED POWER)

Dominant Cause	Failure Mode	Unavailability with Bus(es) Unavailable						
		3A	5A	6A	3A & 5A	3A & 6A	5A & 6A	3A, 5A & 6A
Single Valves	Block Flow Path	6.80×10^{-4}	6.80×10^{-4}	6.80×10^{-4}	6.80×10^{-4}	6.80×10^{-4}	6.80×10^{-4}	1.0
Pump	Fails to Start	6.41×10^{-3}	4.99×10^{-5}	6.41×10^{-3}	6.41×10^{-3}	1.0	6.41×10^{-3}	1.0
MOVs	746/747 Fail to Open	6.48×10^{-6}	2.32×10^{-3}	2.32×10^{-3}	2.32×10^{-3}	2.32×10^{-3}	1.0	1.0
Maintenance	On Pump Train 21 or 22	9.73×10^{-4}	1.27×10^{-5}	9.73×10^{-4}	9.73×10^{-4}	-	9.74×10^{-4}	-
TOTAL		8.07×10^{-3}	3.06×10^{-3}	1.01×10^{-2}	1.01×10^{-2}	1.0	1.0	1.0

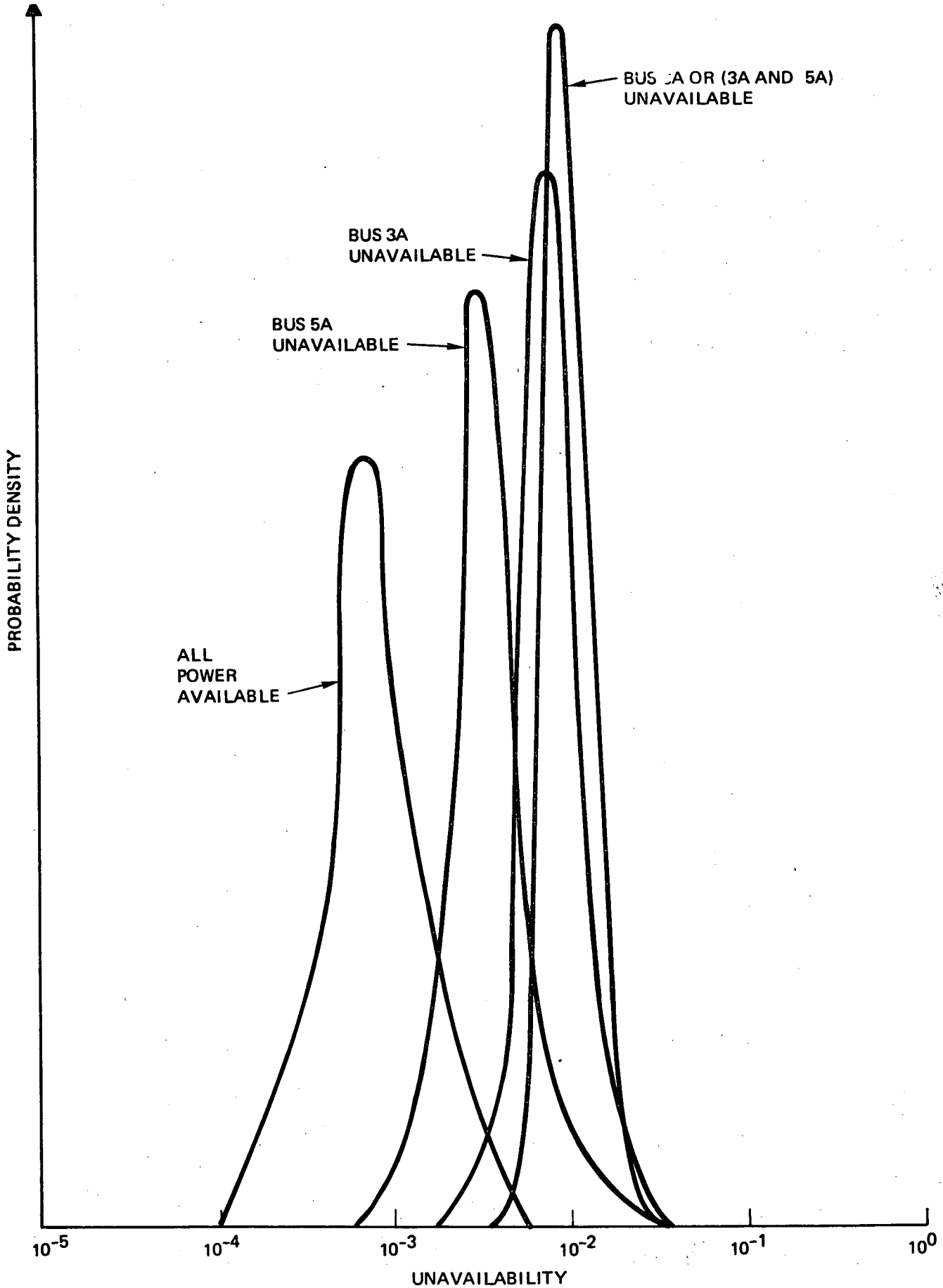


Figure 1.5.2.3.2-1. Indian Point 2 Probability Distribution
Low Pressure Injection System Unavailability

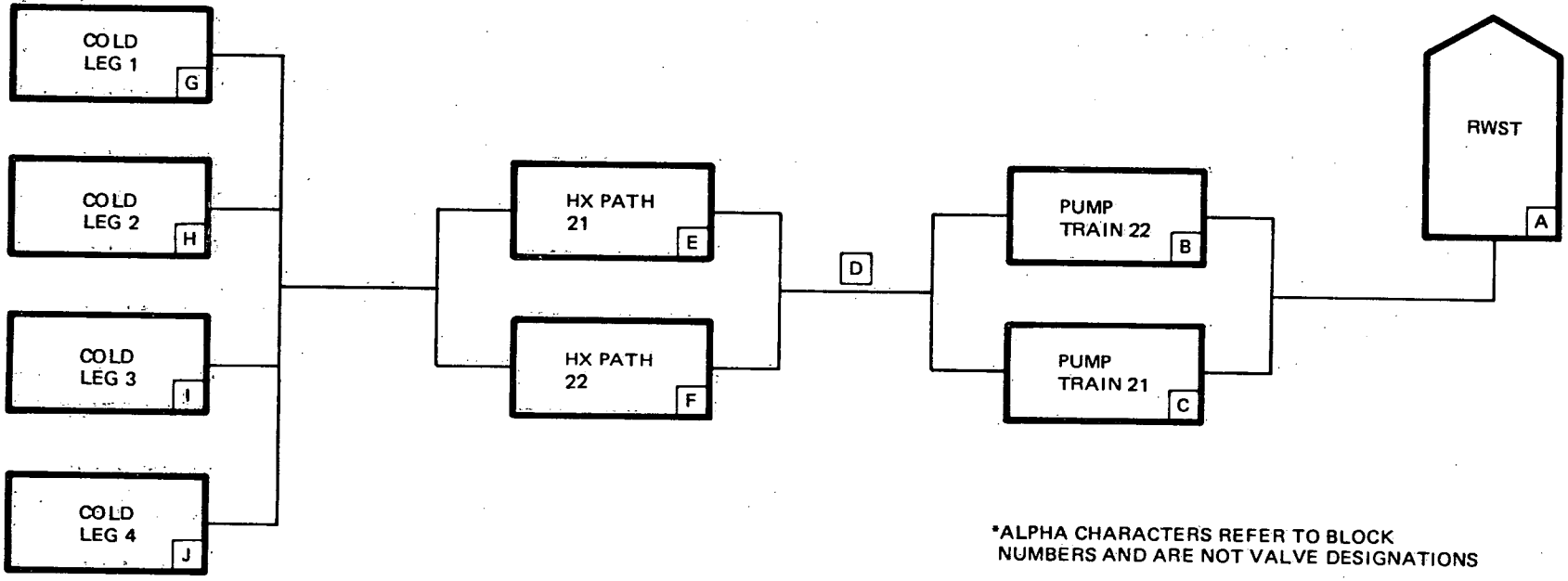


Figure 1.5.2.3.2-2 Indian Point 2 Low-Pressure Injection System Block Diagram

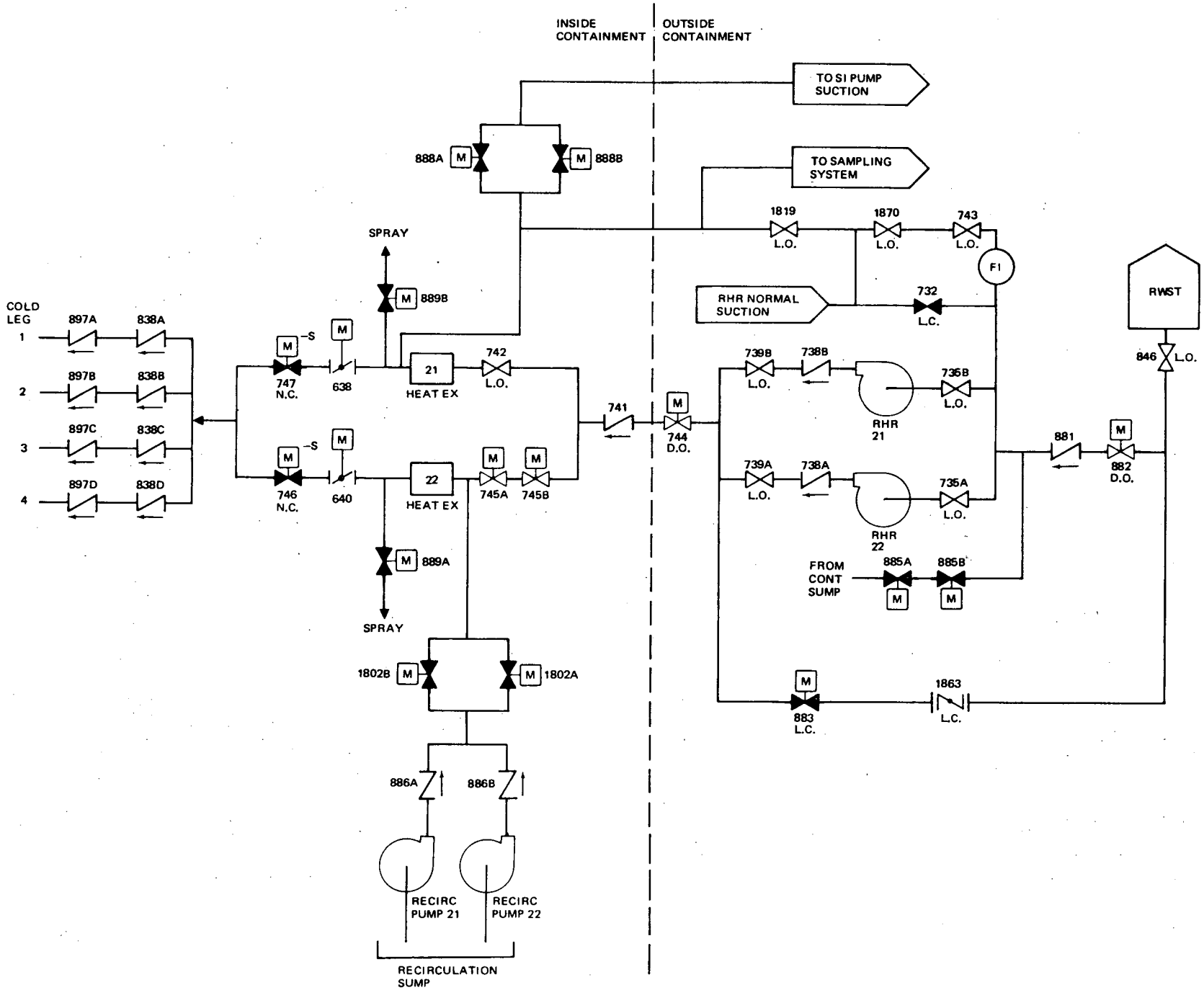


Figure 1.5.2.3.2-3. Indian Point 2 Low Pressure Injection System Simplified P&ID

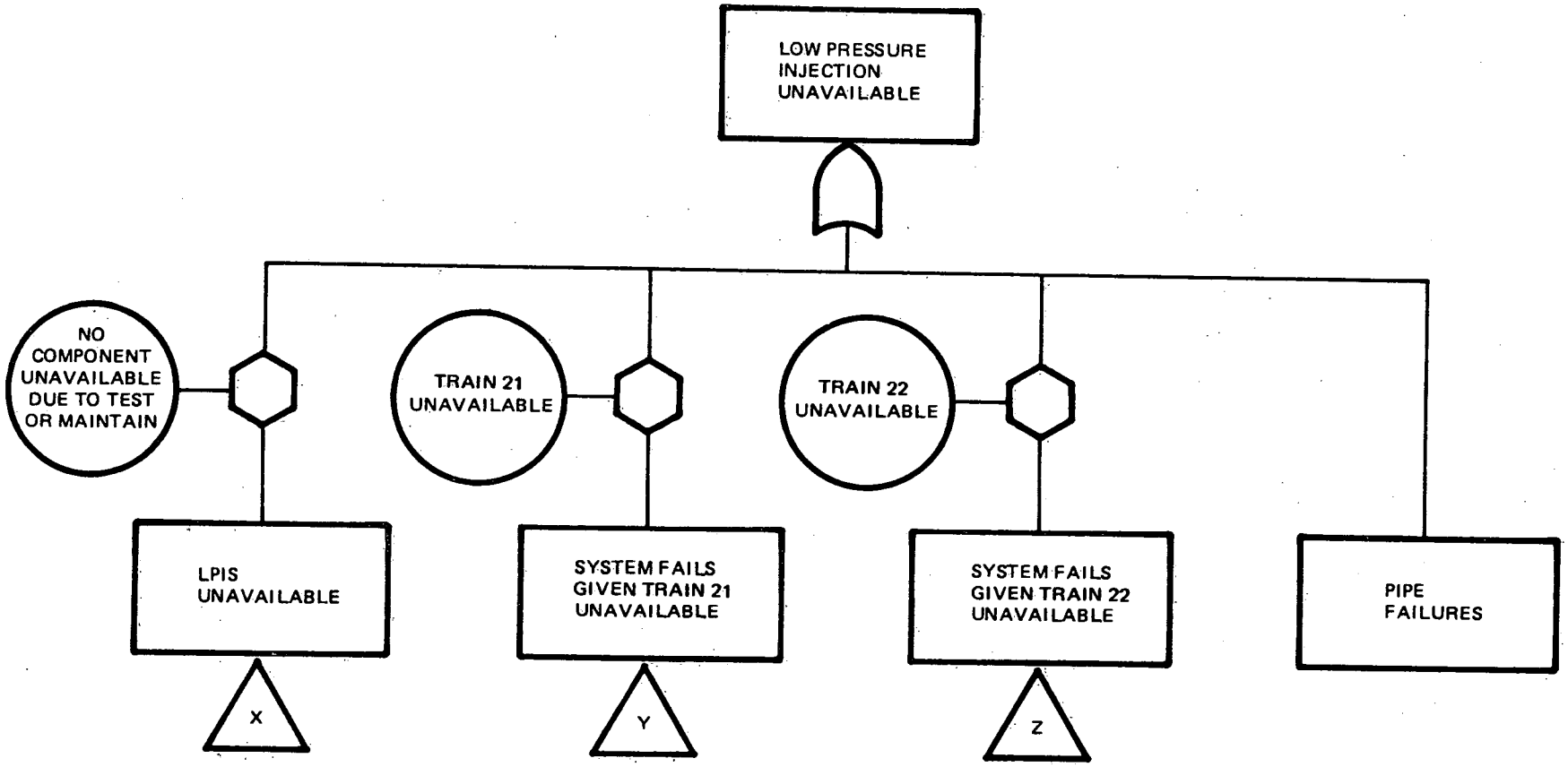


Figure 1.5.2.3.2-4. Indian Point 2 Top Structure of the Fault Tree for Low Pressure Injection System

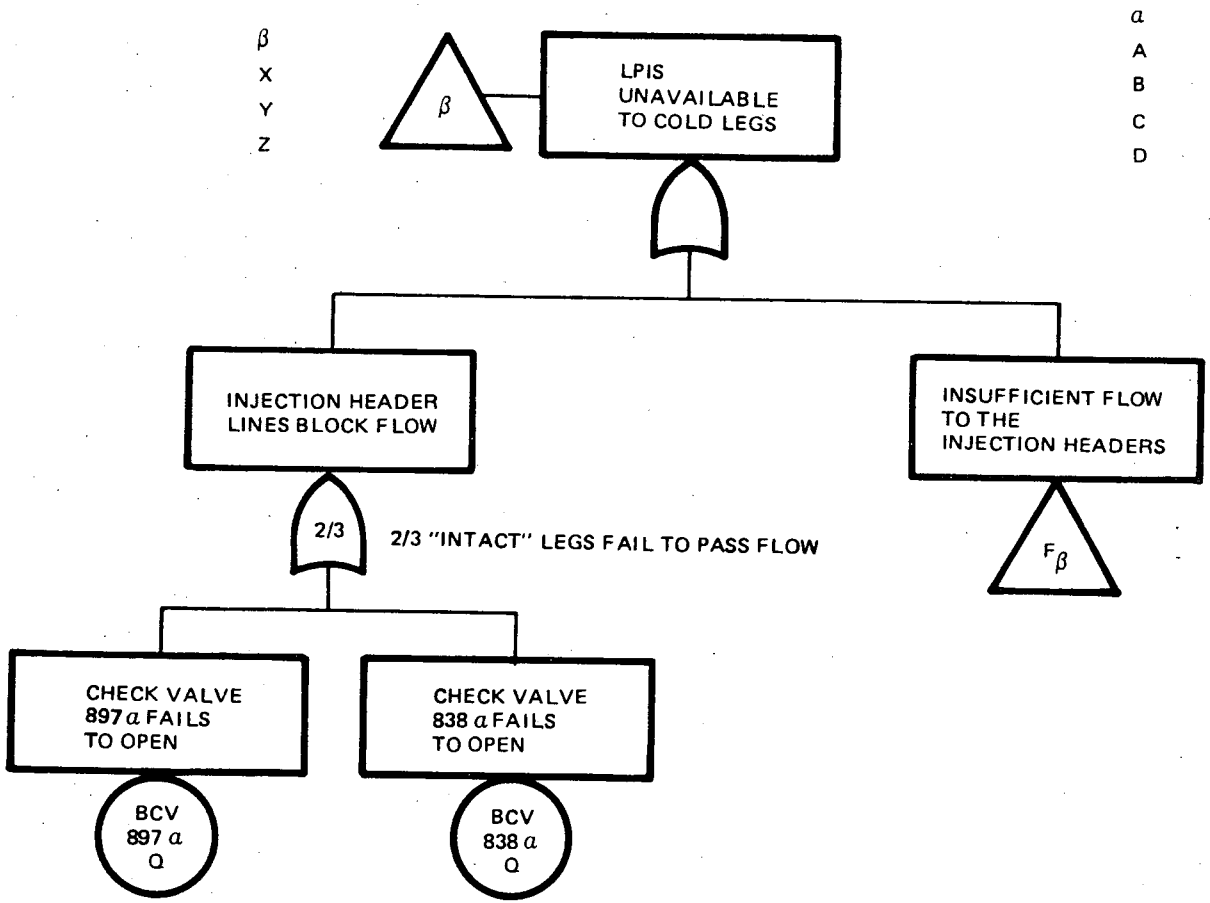


Figure 1.5.2.3.2-5. Indian Point 2 Fault Tree for Low Pressure Injection System (Sheet 1 of 9)

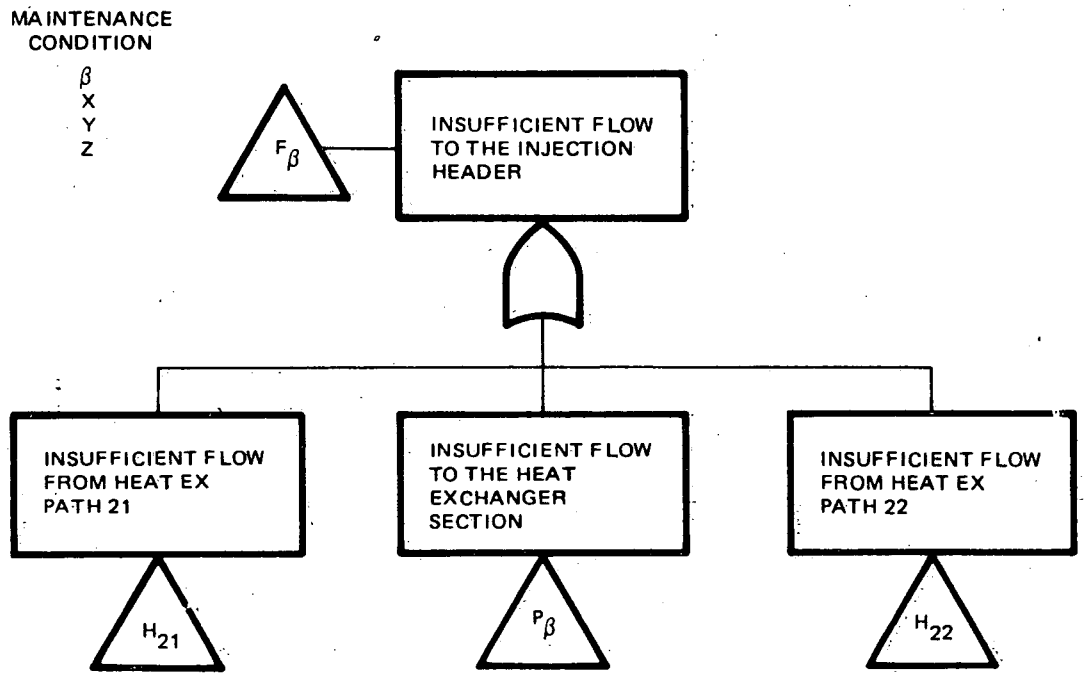


Figure 1.5.2.3.2-5. (Sheet 2 of 9)

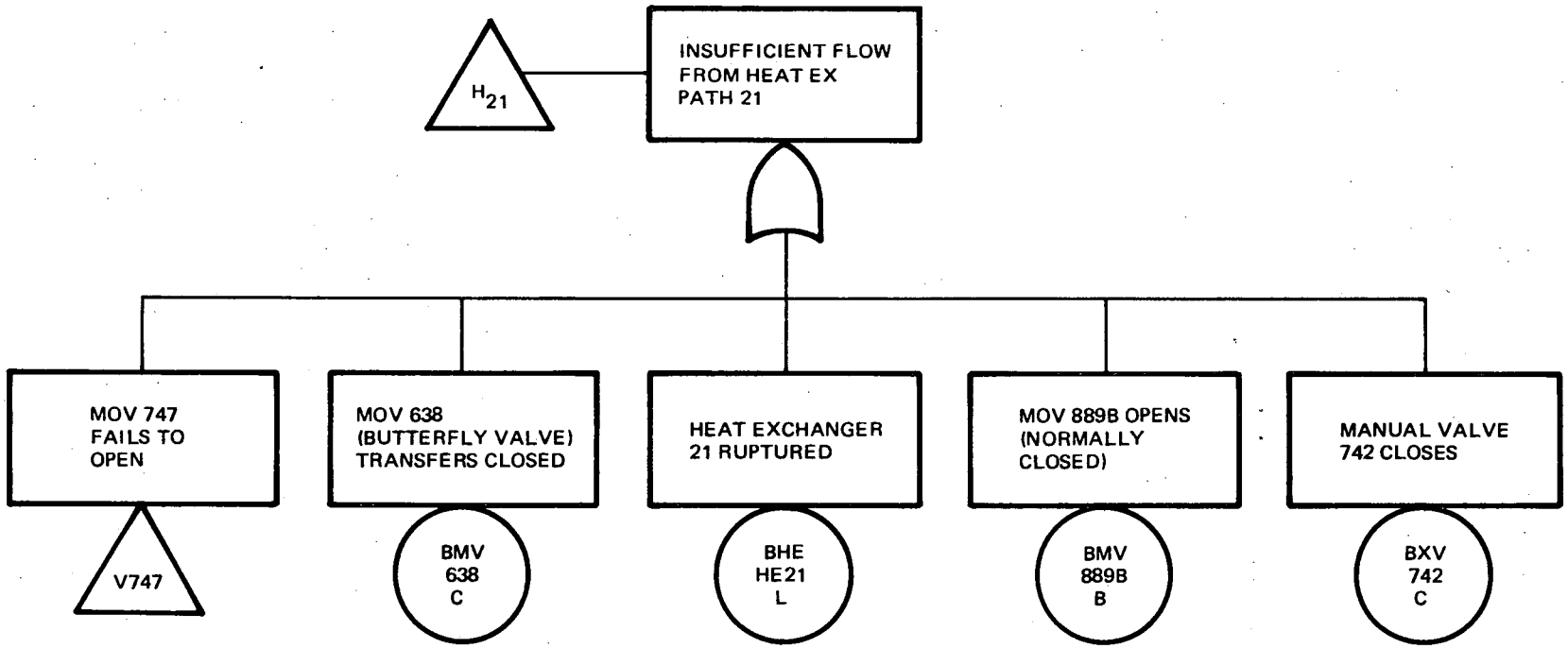


Figure 1.5.2.3.2-5. (Sheet 3 of 9)

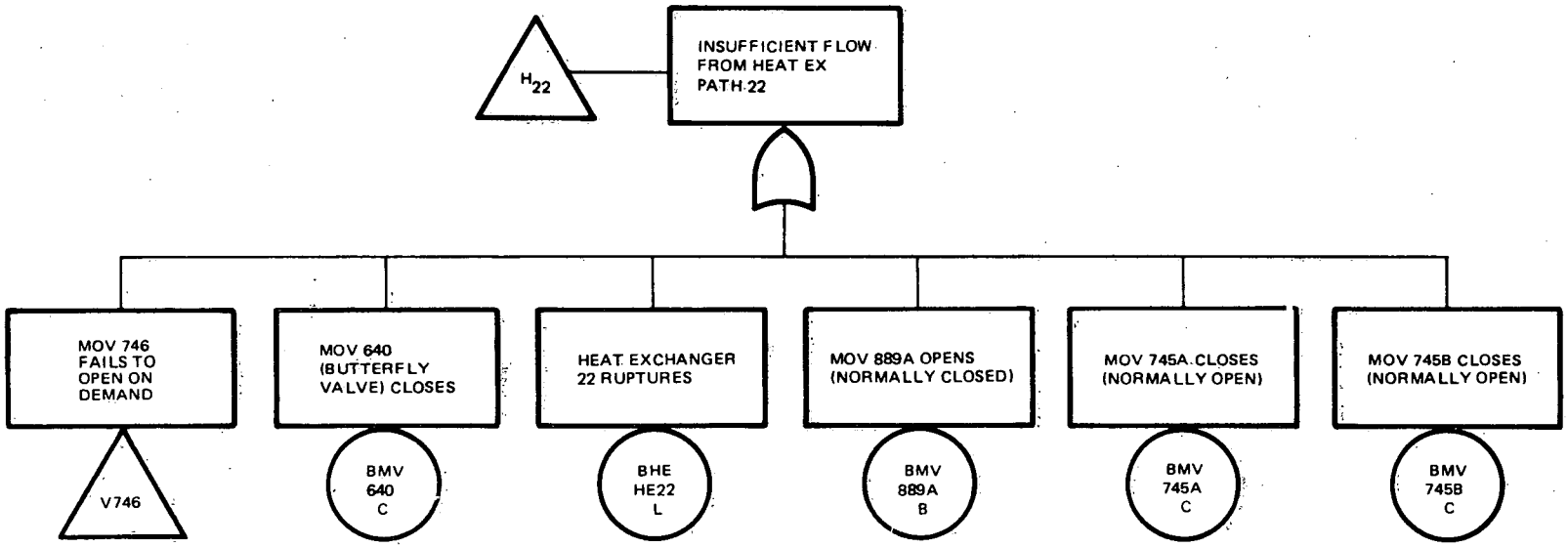
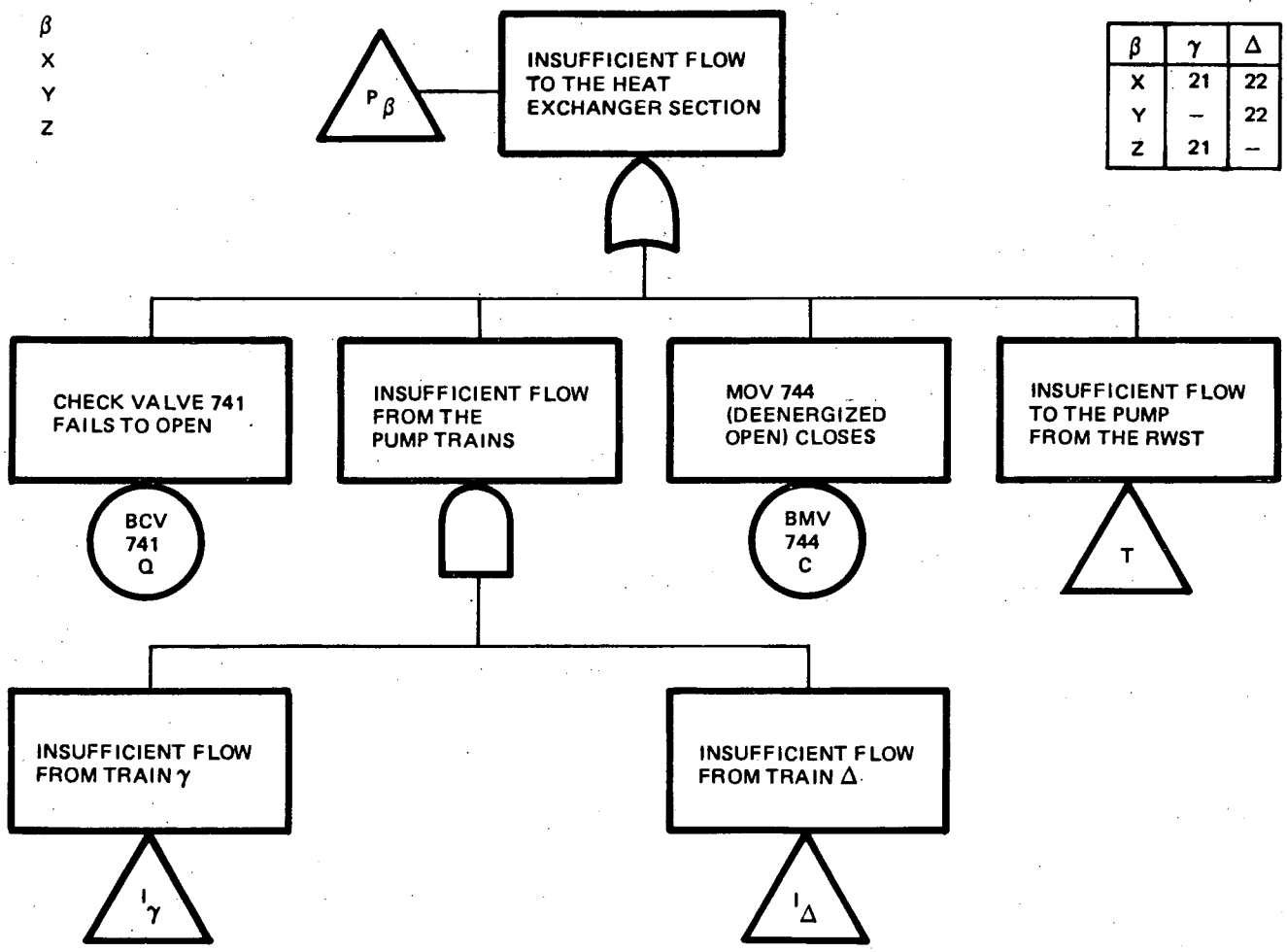


Figure 1.5.2.3.2-5. (Sheet 4 of 9)



β	γ	Δ
X	21	22
Y	–	22
Z	21	–

Figure 1.5.2.3.2-5. (Sheet 5 of 9)

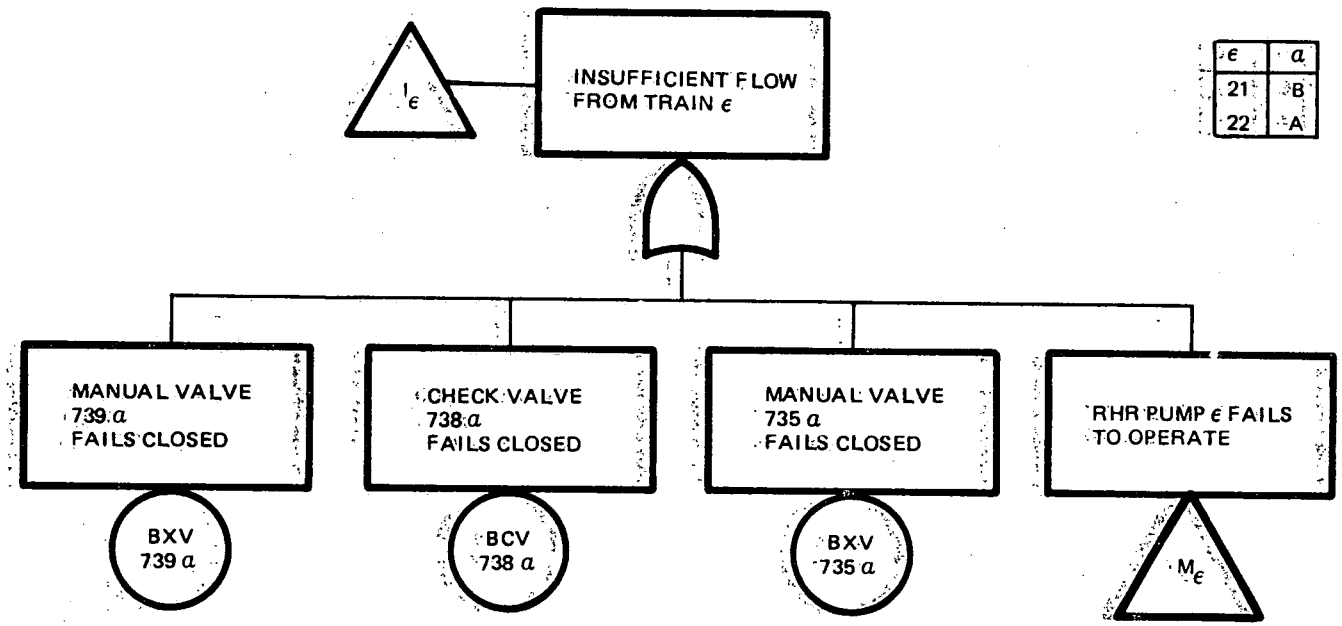


Figure 1.5.2.3.2-5. (Sheet 6 of 9)

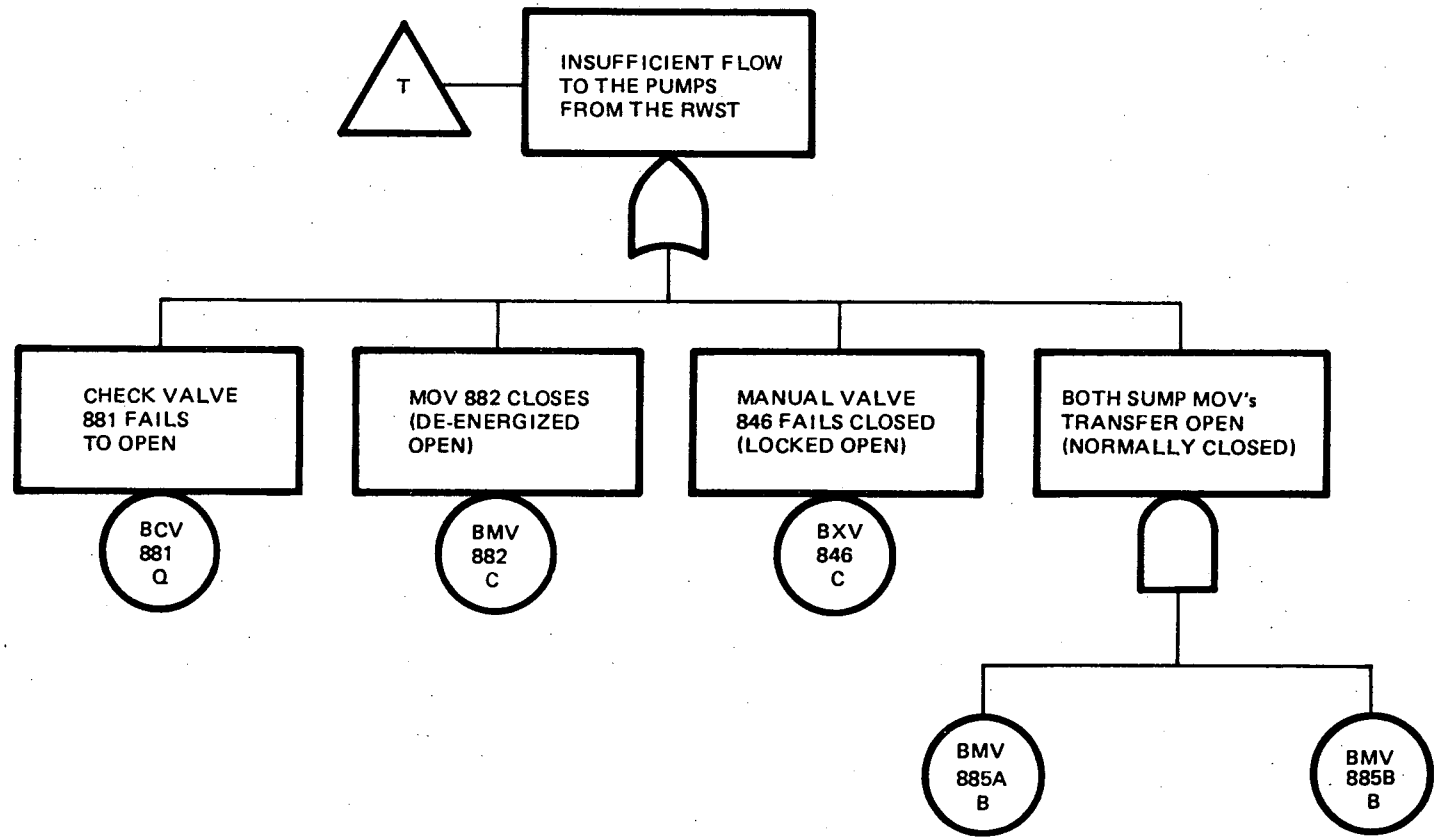
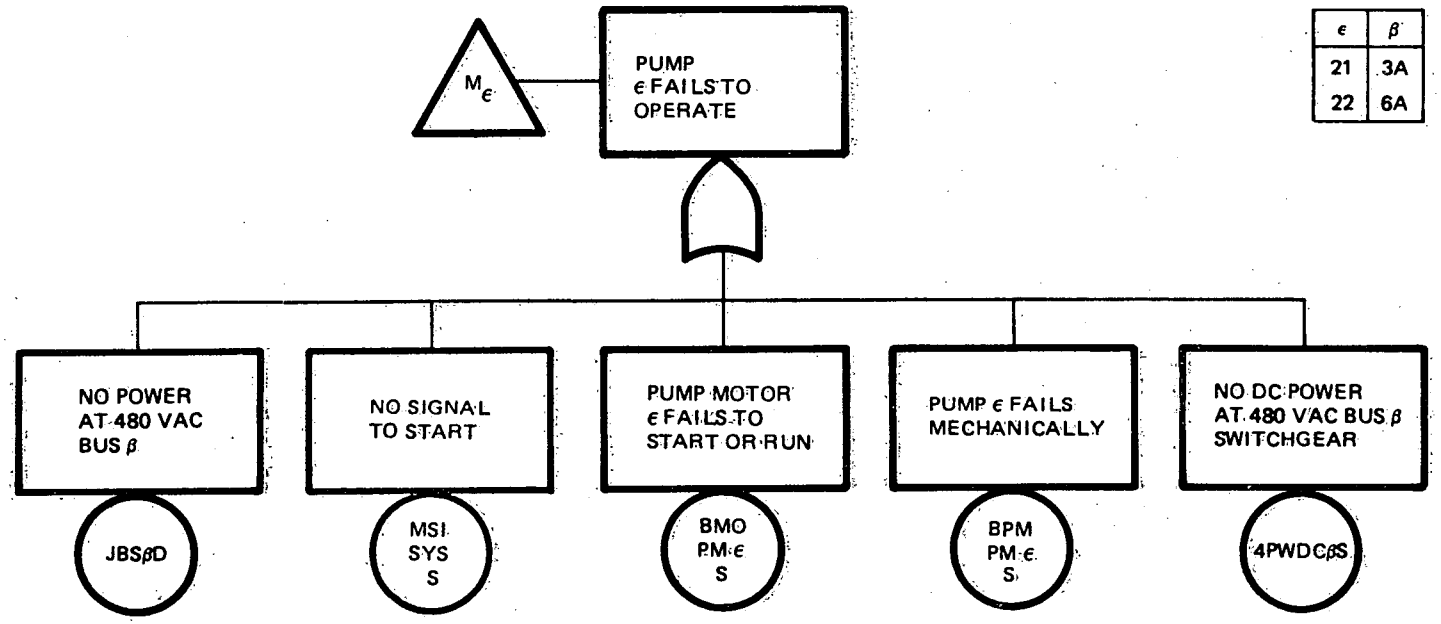


Figure 1.5.2.3.2-5. (Sheet 7 of 9)



ϵ	β
21	3A
22	6A

Figure 1.5.2.3.2-5. (Sheet 8 of 9)

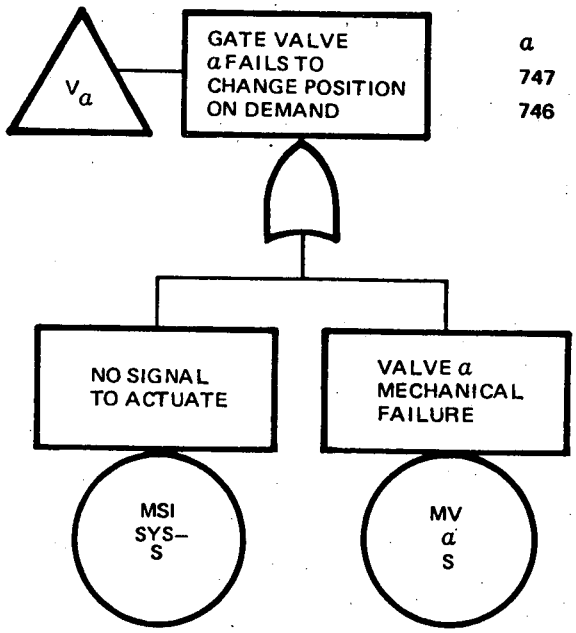


Figure 1.5.2.3.2-5. (Sheet 9 of 9)

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1.5.2.3.3 Indian Point 2 Accumulator System

1.5.2.3.3.1 Summary.

1.5.2.3.3.1.1 Introduction. The accumulator system is evaluated in the context of a large loss of coolant accident (LOCA) in which the pressure in the core decreases enough to allow injection because of the higher pressure nitrogen in each of the accumulator tanks. Success is defined as the injection of three accumulators into the three intact legs, given that a LOCA has occurred on the fourth leg.

The analysis was carried out under the following conditions:

- The refueling water storage tank is available.
- The safeguards actuation signal is present.

The accumulator system does not depend on electric power; therefore, only one calculation was needed for all states of electric power.

In the large LOCA event tree, the accumulator system is incorporated with the low pressure injection system. Both are required for successful emergency coolant injection.

1.5.2.3.3.1.2 Results. Table 1.5.2.3.3-1 summarizes the results of this analysis and compares it to the Reactor Safety Study (RSS) results. The mean unavailability of the system is 1.88×10^{-3}. The probability distribution for the accumulator system unavailability is shown in Figure 1.5.2.3.3-1.

The analysis showed the following dominant contributors to system unavailability:

	Mean
• Accumulator System Unavailability	1.88×10^{-3}
- Motor-operated valves (MOVs)	1.46×10^{-3} (78.0%)
- Check valves	4.20×10^{-4} (22.0%)

1.5.2.3.3.1.3 Conclusions. The check valves and MOVs are the dominant contributors to accumulator unavailability on demand. The tank level, N_2 pressure, and piping failures are insignificant compared to the check valves and MOVs. The resulting mean unavailability on demand (1.88×10^{-3}) represents the loss of any one of the three intact legs, assuming the LOCA occurred on the fourth leg.

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1.5.2.3.3.2 System Description.

1.5.2.3.3.2.1 System Function. For a large LOCA, the accumulator system provides enough water to initiate recovery of the core before the low pressure injection system starts to provide flow, approximately 25 seconds after the LOCA.

1.5.2.3.3.2.2 System Configuration. A block diagram and simplified piping and instrumentation diagram for the system are shown in Figures 1.5.2.3.3-2 and 1.5.2.3.3-3. The success of all three accumulators on the intact injection legs is needed for successful initiation of core recovery.

1.5.2.3.3.2.3 System Operation. When a large break occurs in the reactor coolant system (RCS), the accumulator tanks discharge to initiate recovery of the reactor core. Unlike the previous systems which require pumps for injection, the accumulator tanks are passive, and injection occurs when the RCS pressure drops below the nitrogen gas pressure (nominally 660 psig) in the tanks. Each reactor coolant cold leg pipe has one tank, and all the tanks are identical.

A minimum borated water volume of 716 to 731 cubic feet is maintained in the tanks at all times. Two level sensors provide control room readouts of the level. Low and high level alarms annunciate when the tank level falls or rises from the operating condition by more than a set amount (nominally 723.5 cubic feet).

When the reactor coolant pressure falls below the accumulator pressure, the borated water flows through the motor-operated isolation valves (894A-D), which are normally deenergized open and receive an open safeguards actuation signal. These valves have redundant DC position indication in the central control room when AC power to the valves is deenergized. Flow then continues through the two check valves and into the cold leg piping of the RCS.

Nitrogen gas is nominally maintained in the tank at 660 psig and is monitored by two pressure sensors that provide a control room display of the pressure. An alarm annunciates if the pressure falls or rises from the normal pressure by more than a set amount.

1.5.2.3.3.2.4 Support Systems. The accumulator system is a passive response system so that no other systems need to operate at the time of injection. Level and pressure in the accumulators are monitored during normal operation to ensure the readiness of this system.

1.5.2.3.3.2.5 Test, Surveillance, and Technical Specification Requirements. A check valve leak test is performed during refueling outages for valves 895 A, B, C, D and 897 A, B, C, D. Before the unit is returned to service, and when RCS pressure has fallen within 100 psig of the residual heat removal system design pressure, a check is performed to verify that these valves are in the closed position. MOVs 894 A, B, C, D are cycled every RCS depressurization. Table 1.5.2.3.3-2 shows the components that are tested.

In addition, a flow test is performed during refueling outages (every 18 months) to check that the MOVs are open and to verify that the check valves open on demand.

1.5.2.3.3.2.6 Maintenance Requirements. The plant is not allowed to operate with any accumulator inoperable. The plant is shut down for required maintenance.

1.5.2.3.3.2.7 Operator Interaction. There is no operator interaction with the accumulator system during normal operation other than that described in Section 1.5.2.3.3.2.3 for maintaining proper level and pressure in the accumulators.

1.5.2.3.3.2.8 Common Cause Potential. Because the system is basically a passive system requiring no actuation signals or support systems, no significant common cause potential has been identified. The only active components are the check valves, which are required to open on demand.

1.5.2.3.3.3 Logic Model.

1.5.2.3.3.3.1 Top Events. The top event of "No or Insufficient Flow From the Accumulators" is combined with the low pressure injection system top event in the event tree for the large LOCA. Because the MOVs are deenergized open, there is no power requirement for these systems.

1.5.2.3.3.3.2 System Fault Tree. The tree for each accumulator (shown in Figure 1.5.2.3.3-4) is an OR gate with two check valves and an MOV that is normally deenergized open. The MOV also receives a safeguards actuation signal to open in case it has been energized and closed. For a large LOCA, all three accumulators on good legs must provide flow to successfully initiate recovery of the core. Therefore, any of the nine valves that fail to allow flow will cause a failure of the accumulator system. Other failures of low tank level and pressure and pipe failure are also shown. Their contribution will be discussed in the quantification section.

1.5.2.3.3.3.3 Fault Tree Coding and Basic Events. Table 1.5.2.3.3-3 shows the basic events and indicates the failure mode and mean failure rate. Each of these is a single element cutset because any one failure causes the system to fail. The result is nine single-event failures that cause a top event failure.

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1.5.2.3.3.4 Quantification.

1.5.2.3.3.4.1 Hardware Contribution. Each single-event minimal cutset is analyzed using plant specific data. Because all intact legs must provide flow to ensure success of the accumulators, the two check valves and one deenergized open MOV must allow flow on each intact leg. Therefore, the following data were used with six check valves and three MOVs having the following unavailability values for this plant.

- Check Valve Fails to Open (six):

  Mean: 7.02×10^{-5}

- MOV Fails Closed (deenergized open) (three):

  Mean: $7.40 \times 10^{-8} \times \frac{13,140^{*}}{2} = 4.86 \times 10^{-4}$

- Pipes. Table 1.5.2.3.3-4 shows the pipe sections that constitute single failures of the accumulators. Pipe failure contributions are estimated to be less than 10^{-10} per hour, as discussed in the methods section.

- Nitrogen Pressure. Each accumulator has two redundant pressure sensors to continuously detect inadequate pressure on each accumulator. It is estimated that the frequency of undetected low pressure in an accumulator will not be worse than 10^{-6}/demand.

- Water Level. Each accumulator has two redundant level sensors to continuously detect inadequate water level in each accumulator. It is estimated that the frequency of undetected low level in an accumulator will not be worse than 10^{-6}/demand.

The hardware contribution to the mean system unavailability is:

Mean = six check valve failures + three MOV failures

$= 6(7.02 \times 10^{-5}) + 3(4.86 \times 10^{-4})$

$= 4.20 \times 10^{-4} + 1.46 \times 10^{-3}$

$= 1.88 \times 10^{-3}$

*Based on the plant refueling cycle of 18 months, one-half of the refueling cycle (9 months or 13,140/2 = 6,570 hours) was considered the mean time to repair. Although the valve stem is deenergized open, the flow path may be blocked if the gate has parted from the valve stem. Only a flow test that is conducted every refueling cycle will verify that the gate is open.

1.5.2.3.3.4.2 Test and Maintenance Contribution. As discussed in Section 1.5.2.3.3.2.4, tests on the system are performed during shutdown conditions and any maintenance on the system during operation requires a plant shutdown. Therefore, no unavailability contribution is evaluated from test and maintenance.

1.5.2.3.3.4.3 Human Error Contribution. Because this is a passive system, there is no human interaction other than maintaining proper level and pressure in the accumulators during normal operation. Therefore, there is no contribution to overall system unavailability because of human error.

TABLE 1.5.2.3.3-1

INDIAN POINT 2 ACCUMULATOR UNAVAILABILITY ON DEMAND

Analysis	Mean	Variance	5th Percentile	Median	95th Percentile
1. This Study	1.88×10^{-3}	2.46×10^{-5}	4.95×10^{-4}	1.45×10^{-3}	4.70×10^{-3}
2. RSS	Not Given	Not Given	6.2×10^{-4}	9.5×10^{-4}	1.4×10^{-3}

TABLE 1.5.2.3.3-2

INDIAN POINT 2 ACCUMULATOR TESTING REQUIREMENTS

Component	Testing
Check Valves 897A, B, C, D	Cycled every RCS depressurization*
Check Valves 895A, B, C, D	Cycled every refueling*
MOV 894A, B, C, D	Cycled every RCS depressurization and flow tested open every refueling

*Tested for leakage every refueling; tested to assure closure every RCS repressurization.

TABLE 1.5.2.3.3-3

INDIAN POINT 2 ACCUMULATOR LIST OF COMPONENTS

Component	Failure Mode	Fault Tree Coding	Mean Failure Rate	Variance	Data Source (Table 1.5.1-4)
Check Valves					
897 (A, B, C, D)	Fails to open	BCV 897 (A,B,C,D)Q	7.02×10^{-5}	1.09×10^{-8}	Item 3
895 (A, B, C, D)	Fails to open	BCV 895 (A,B,C,D)Q	7.02×10^{-5}	1.09×10^{-8}	Item 3
Motor-Operated Valves					
894 (A, B, C, D)	Transfers closed (Deenergized open)	BMV 894 (A,B,C,D)Q	7.40×10^{-8}	5.89×10^{-15}	Item 1

TABLE 1.5.2.3.3-4

INDIAN POINT 2 ACCUMULATOR SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential for Other Systems Impact	Initiating Event	Comments
Accumulator 21 outlet upstream of check valve 895A	10	Yes, under analysis assumptions	None	No	Loss of a single accumulator
Accumulator 21 downstream of check valve 895A to check valve 897A	10	Yes, under analysis assumptions	Yes, loss of one injection path for low pressure injection and one injection path for high pressure injection.	No	Loss of a single accumulator
Accumulator 23 outlet upstream of check valve 895C	10	Yes, under analysis assumptions	None	No	Loss of a single accumulator
Accumulator 23 downstream of check valve 895C to check valve 897C	10	Yes, under analysis assumptions	Yes, loss of one injection path for low pressure injection and one injection path for high pressure injection.	No	Loss of a single accumulator
Accumulator 22 outlet upstream of check valve 895B	10	Yes, under analysis assumptions	None	No	Loss of a single accumulator
Accumulator 22 downstream of check valve 895B to check valve 897B	10	Yes, under analysis assumptions	Yes, loss of one injection path for low pressure injection.	No	Loss of a single accumulator

TABLE 1.5.2.3.3-4 (continued)

INDIAN POINT 2 ACCUMULATOR SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential for Other Systems Impact	Initiating Event	Comments
Accumulator 24 outlet upstream of check valve 895D	10	Yes, under analysis assumptions	None	No	Loss of a single accumulator
Accumulator downstream of check valve 895D to check valve 897D	10	Yes, under analysis assumptions	Yes, loss of one injection path for low pressure injection.	No	Loss of a single accumulator

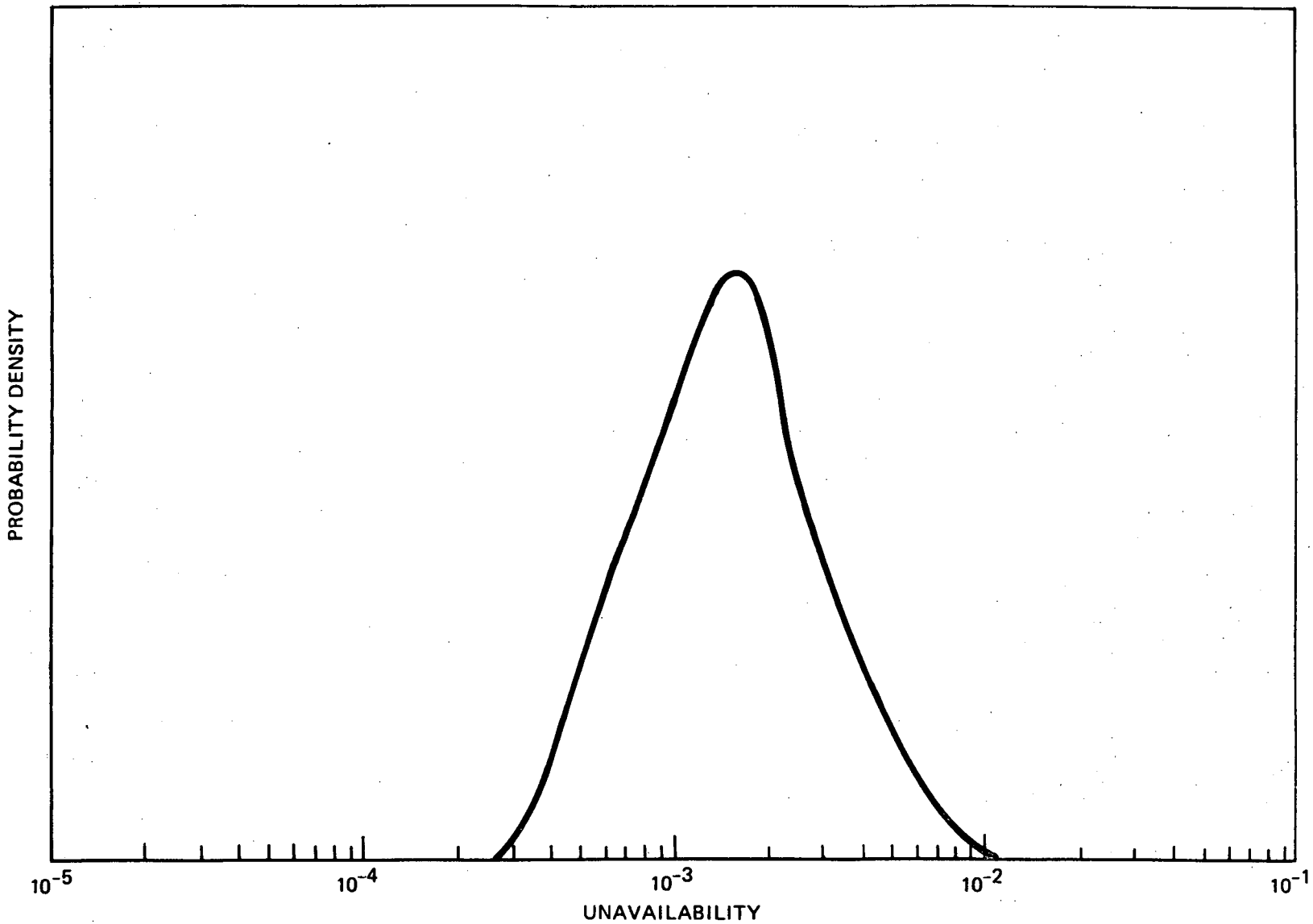


Figure 1.5.2.3.3-1. Indian Point 2 Accumulator System Unavailability Probability Distribution

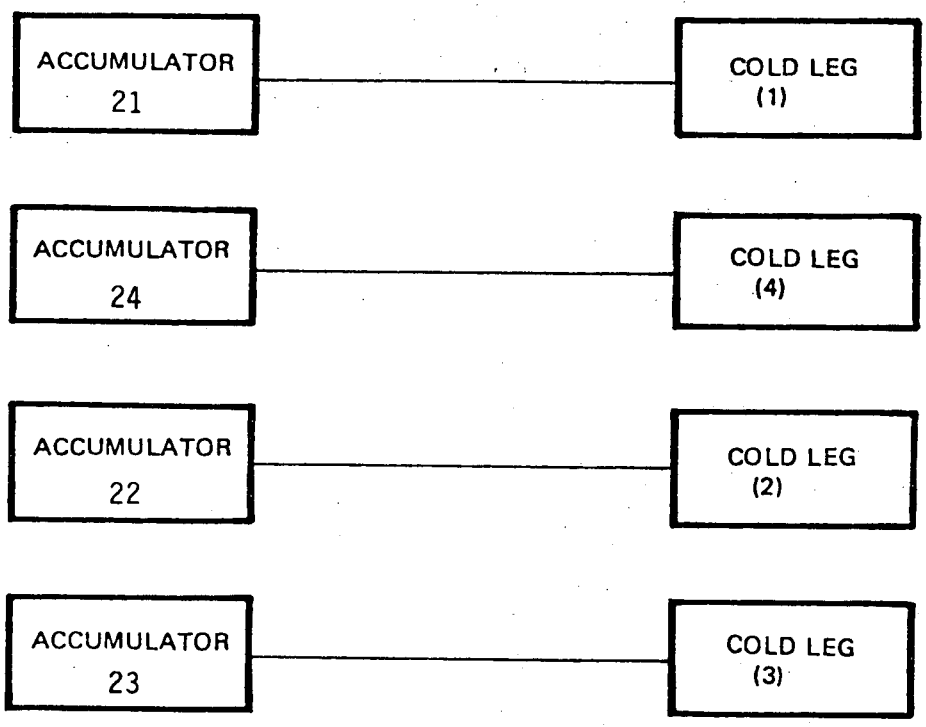
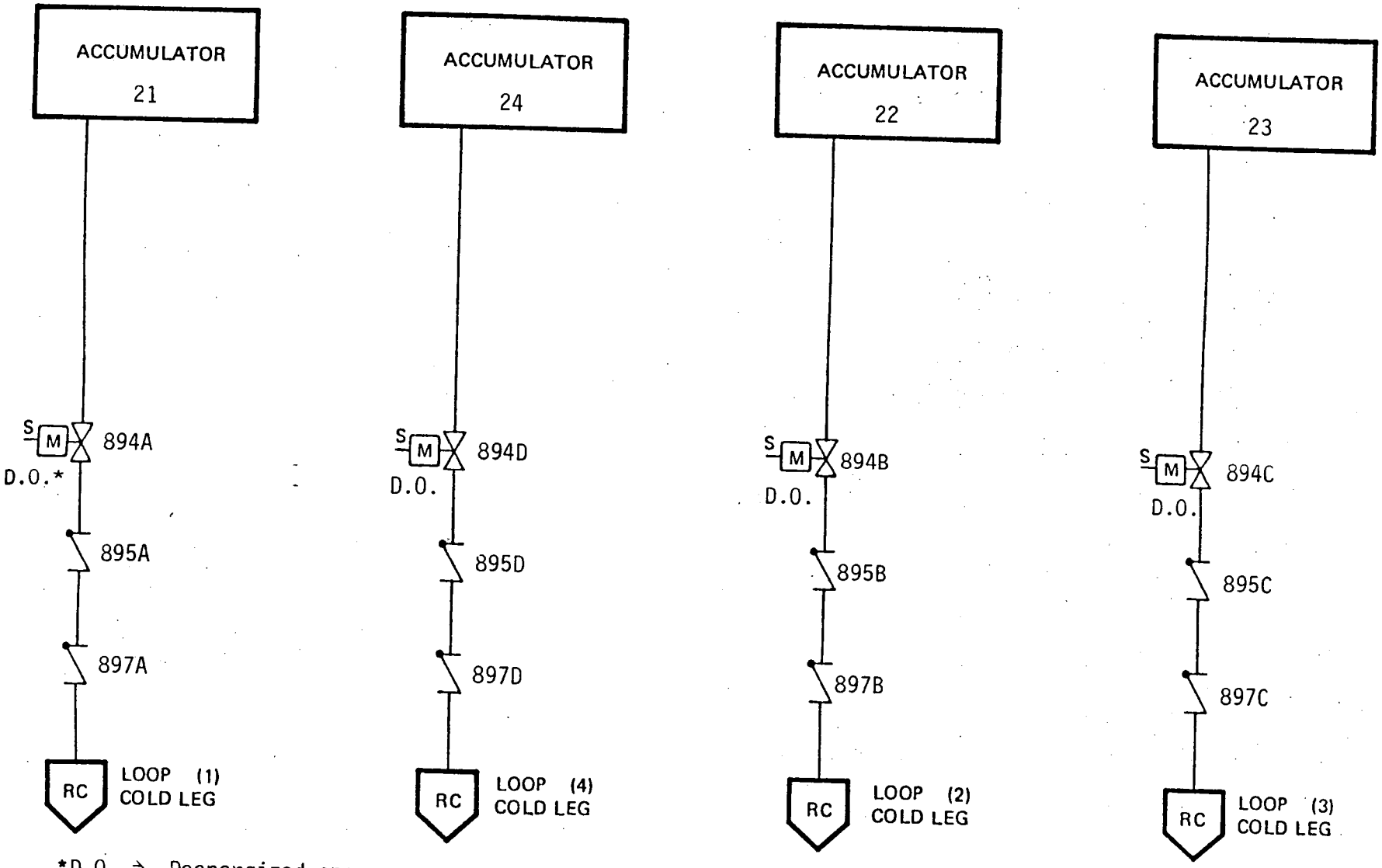


Figure 1.5.2.3.3-2. Indian Point 2 Accumulator Block Diagram



*D.O. → Deenergized open.

Figure 1.5.2.3.3-3. Indian Point 2 Accumulator Simplified Piping and Instrumentation Diagram

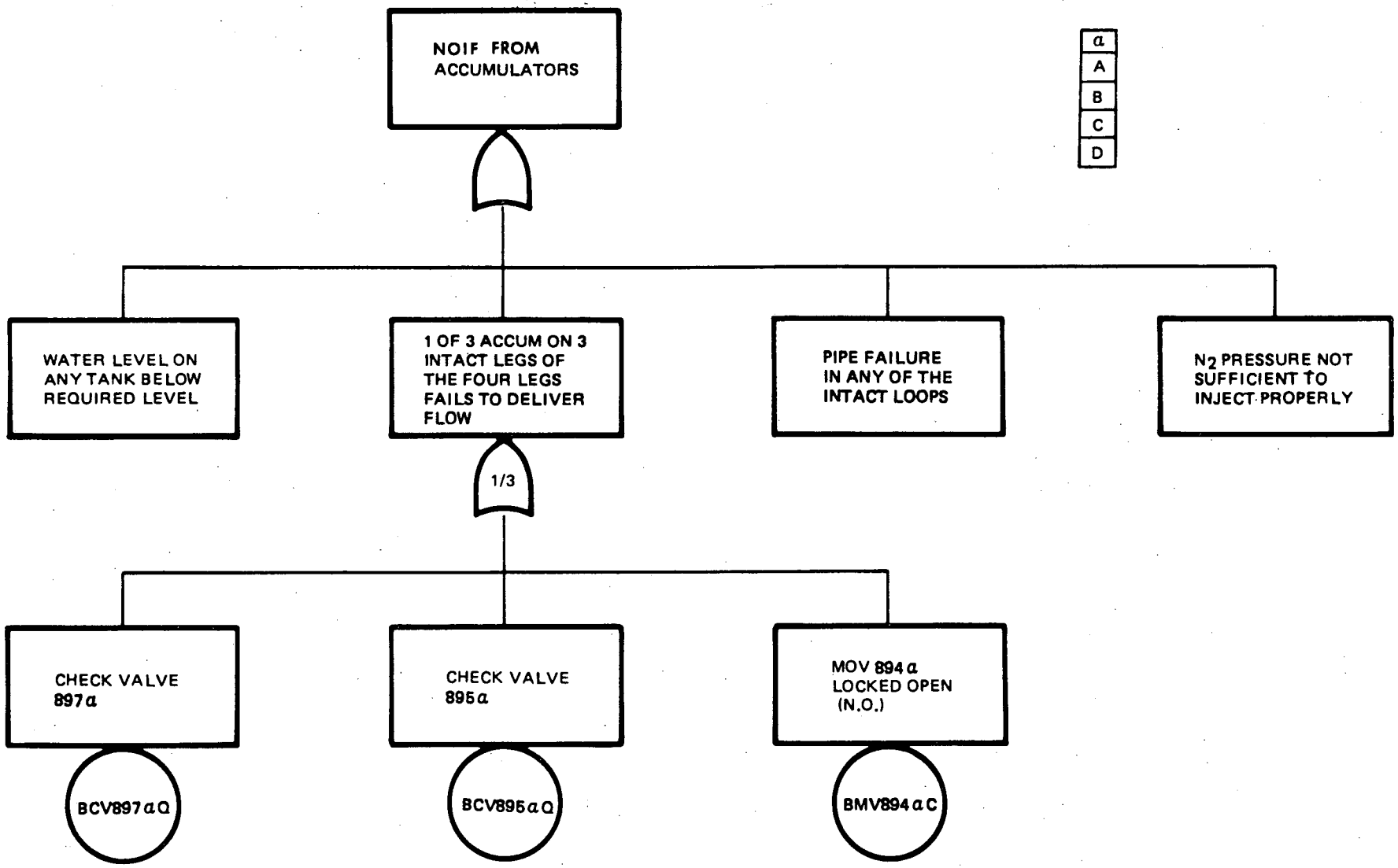


Figure 1.5.2.3.3-4. Indian Point 2 Accumulator System Fault Tree

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1.5.2.3.4 Indian Point 2 Recirculation System

1.5.2.3.4.1 Summary.

1.5.2.3.4.1.1 Introduction. The recirculation phase is evaluated in the context of a loss of coolant accident (LOCA). This phase calls for the combined operation of several systems and components: the residual heat removal (RHR) system, the containment sump, the recirculation sump and pumps, the safety injection (SI) system, and containment spray nozzles. For ease of reference, this group is called the recirculation system. The system is initiated by the operators when the water level in the refueling water storage tank (RWST) is at "low level" alarm point. The function of this system is to provide long term core cooling and containment spray for a LOCA of any break size. For core cooling, the system can be operated in three different modes: high pressure, low pressure, and hot leg recirculation.

The analysis is carried out under the following conditions:

- Reactor trip has been successful (small LOCA).
- Injection phase has been completed successfully.
- System is analyzed for 24 hours.
- One heat exchanger can provide sufficient cooling.
- Success of the low head recirculation is defined as one low pressure pump supplying cooling water to the core for 24 hours.
- Success of the high head recirculation is defined as one safety injection pump supplying cooling to the core for 24 hours.
- Success of the containment spray recirculation is defined as one low head pump supplying water to one spray header.
- Success of the hot leg recirculation is defined as one safety injection pump supplying water to one hot leg.

1.5.2.3.4.1.2 Results. In a small LOCA, core cooling recirculation by the SI pumps (high head recirculation) should be available, and containment spray, low head, and hot leg recirculation are not necessary. High head recirculation is analyzed under several conditions depending on the availability of fan coolers, component cooling system (CCS), and necessary electrical power supplies. The CCS provides the cooling water for the RHR heat exchangers. If the CCS is unavailable, the containment fan coolers would remove the decay heat by condensing the steam generated in

the core. Table 1.5.2.3.4-1 summarizes the boundary conditions and the results. A list of dominant contributors for some representative cases follows:

	Mean
• High Head Recirculation (small LOCA)	
- With Power On All Buses, Fan Coolers Unavailable, and Component Cooling Available	6.8×10^{-4} (total)
• Operator error	3.9×10^{-4} (58%)
• Hardware failures	2.9×10^{-4} (42%)
- With Power on Bus 5A Lost, Fan Coolers Unavailable, and Component Cooling Available	4.3×10^{-3} (total)
• Single failures	
- MOV 822B fails to open	2.30×10^{-3} (53%)
• Double failures	
- Recirculation pump 22 fails to run and operators fail to align the RHR pumps.	8.60×10^{-4} (20%)
- MOV 1802B fails to open and operators fail to align the RHR pumps.	2.90×10^{-4} (7%)

In Table 1.5.2.3.4-1 the RSS results are quoted for comparison. However, their high pressure recirculation system (HPRS) is different from the high head recirculation system analyzed here.

The following functions should be available in a large or medium LOCA: core cooling recirculation through the low pressure headers, containment spray recirculation, and hot leg recirculation. Part of the recirculation flow is directed into the hot legs (24 hours after the accident) in the hot leg recirculation mode. These functions are analyzed under several conditions similar to those analyzed for the high head recirculation; i.e., availability of fan coolers, CCS, and electric power. Tables 1.5.2.3.4-2 through 1.5.2.3.4-4 summarize the results for each case. A list of dominant contributors for some representative cases follows:

	Mean
• Low-Head Recirculation (large or medium LOCA)	
- With Power On All Buses, Fan Coolers Unavailable, and Component Cooling Available	5.5×10^{-3} (total)
• Operator error	5.3×10^{-3} (97%)

	Mean
- With Power On Bus 5A Lost, Fan Coolers Unavailable, and Component Cooling Available	5.1×10^{-3} (total)
• Operator error	3.9×10^{-2} (77%)
• Recirculation pump 22 fails to start	6.9×10^{-3} (13%)
• MOV 1802B fails to open	2.3×10^{-3} (5%)
• MOV 822B fails to open	2.3×10^{-3} (5%)
• Containment Spray Recirculation (large or medium LOCA)	
- With Power On All Buses	1.5×10^{-3} (total)
• Operator error	1.5×10^{-3} (99%)
- With Power On Bus 5A Lost	3.8×10^{-3} (total)
• Operator error	1.5×10^{-3} (39%)
• MOV 889B fails to open	2.3×10^{-3} (61%)
• Hot Leg Recirculation (large or medium LOCA)	
- With Power On All Buses	
• MOVs 856B and 856F fail to open	6.6×10^{-5} (100%)
- With Power On Bus 5A Lost	
• MOV 856B fails to open	2.3×10^{-3} (100%)

1.5.2.3.4.1.3 Conclusions. Operator error in activating the recirculation phase was an important contributor in almost all cases that are analyzed here. Failure to initiate switchover is the main component of this failure mode. In all cases, the unavailability of electrical buses 5A or 6A has a significant impact on system reliability. However, in most cases, the simultaneous loss of electrical buses 2A and 3A leads to a slight increase in system unreliability. Also, in most cases, the effect of fan cooler availability is insignificant. Probability distributions of recirculation system failure under the specified boundary conditions are shown in Figures 1.5.2.3.4-1 through 1.5.2.3.4-4.

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1.5.2.3.4.2 System Description.

1.5.2.3.4.2.1 Purpose of the System. The recirculation system provides long term core cooling and containment spray after a LOCA of any break size. It recirculates the sump water back into the core and/or spray nozzles after passing it through the RHR heat exchangers.

1.5.2.3.4.2.2 System Diagram. Figures 1.5.2.3.4-5 and 1.5.2.3.4-6 show a block diagram and a simplified piping and instrumentation diagram of this system.

1.5.2.3.4.2.3 System Configuration and Operation.

1.5.2.3.4.2.3.1 System configuration. The recirculation system is a combination of several systems and components. These include the RHR system, containment sump, recirculation sump and pumps, and SI system. The containment sump is separate from the recirculation sump and is located inside the missile barrier. Both sumps are covered with gratings, screens, and baffles to clear the water of debris (particles greater than 1/4 inch) and to reduce water velocity to minimize debris carryover. The water level in these sumps is monitored in the control room on the safeguards panel. Drainage trenches also carry the water to the sumps.

The two recirculation pumps are vertical, centrifugal type pumps with 3,000 gpm capacity at approximately 150 psig. They are driven by 350 hp electric motors which have air-to-water heat exchangers. The motors are more than 2 feet above the highest anticipated post-injection phase water level. The water to these heat exchangers is supplied by the auxiliary component cooling pumps (booster pumps) or main component cooling loop. The booster pumps are started by the SI system to protect the motors of the recirculation pumps from possible damage caused by containment high temperature conditions before the switchover to recirculation.

The RHR heat exchangers have a vertical shell and U-tube design. The shell side contains the cooling medium (component cooling water), and the tube side contains the recirculated fluid. At accident conditions, each heat exchanger is capable of cooling 1.4 million pounds of water per hour from 213^{0}F to 135^{0}F.

Four pumps can take suction from the sumps. The two recirculation pumps (located inside the containment) take suction from the recirculation sump, and two RHR pumps (located outside the containment) take suction from the containment sump. The configuration of components in the recirculation system is such that the low head pumps (i.e., recirculation or RHR pumps) take suction from a sump and pass the coolant through the RHR heat exchangers. Either one of the four pumps can provide sufficient coolant flow to cool the core and simultaneously spray the containment. Depending on the operator decision and the pressure in the reactor coolant system (RCS) and in the containment, the flow is routed for core cooling or containment spray, or both. Priority is given to core cooling.

The RHR heat exchangers cool the sump water. Their secondary side is connected to the CCS which is cooled by the service water system (SWS) drawn from the ultimate heat sink (Hudson River). The component cooling outlet valves (for each heat exchanger), 822A and 822B, are opened by the safeguards actuation signal. If heat exchanger cooling is not available, the fan coolers can remove the heat from the containment atmosphere by condensing the steam generated in the core. In the recirculation phase, any three of the five fan coolers can remove all the decay heat following a large LOCA.

Flow can be directed in four different directions from the heat exchangers. Core and containment conditions determine which flow path should be chosen. The path for low pressure cold leg recirculation is the same as for low pressure injection and is opened by the safeguards actuation signal. If the RCS pressure is above the shutoff head of the low pressure pumps (477 feet for the recirculation pumps and 372 feet for the RHR pumps), the flow is directed toward the suction line of the SI system pumps for high head recirculation. The third path leads to the containment spray headers. Hot leg recirculation is also possible (high head only). The isolation valves to the hot legs are normally closed and deenergized. If one heat exchanger train is unavailable, it is possible to align the other train for simultaneous core cooling and containment spray recirculation. Also, if high head injection is needed and the connecting pipe 60 between the RHR heat exchangers and the SI system pumps is closed or failed, then the RHR pump flow can be realigned (by opening motor-operated valve (MOV) 883 and manual valve 1863, and closing MOV 882 and manual valve 846) toward the suction side of the SI system pumps. Depending on the location of the failure on pipe 60, manual valve 898 must be opened and MOV 887A or 887B must be closed as well. The heat exchangers are bypassed in this situation. Therefore, this mode of recirculation will be successful only if the containment fan coolers are available to remove the heat generated in the core.

1.5.2.3.4.2.3.2 System operation. The operators activate the recirculation system when they receive a "low level" signal from the RWST (a one out of two system). For a large LOCA, this is about 20 minutes after the initiation of the accident if all pumps are running. This could take much longer depending on the number of pumps taking suction from the RWST. The operators also check the containment water level (sump level) to verify that the injection water has, in fact, been delivered to the containment. The switchover from the injection phase to the recirculation phase is done by eight switches (referred to as the "eight-switch sequence"). Following switchover, one spray pump is left to operate until the RWST is empty. Core cooling has the first priority. Containment spray recirculation is activated manually later. Its operation depends on containment pressure.

The operators turn the recirculation switches to the "On" position, one at a time, starting with switch 1. A light is associated with each switch to indicate that the required automatic operations are completed. If a particular switch attempts to actuate a deenergized component, the "Function Complete" light will not turn on. These are identified in the emergency procedure. Operators will check the status

of components affected by these switches. If some functions are not completed, the operator will finish them manually according to the emergency procedure. Switch 1 trips SI pump 22 (if all three are running) and spray pump 22 (if both pumps are running), closes MOVs 887A and 887B (if SI pump 22 is stopped), and closes the discharge MOVs 866A and 866B (these are not shown in Figure 1.5.2.3.4-6) if the containment spray pump 21 is shutdown, or MOVs 866C and 866D if spray pump 22 is shutdown. Switch 2 activates one additional service water pump and one component cooling pump. Both RHR pumps are stopped and RHR suction and discharge valves (882 and 744) are signaled to close by switch 3. Both valves are deenergized; therefore, a plant operator must energize them before they can be closed from the control room. This action is performed after the recirculation switchover is completed. One of the recirculation pumps is started and both discharge valves (1802A and 1802B) are opened by switch 4. If three diesels or offsite power are available, one more service water pump, a second component cooling pump, and a second recirculation pump will be started by switch 5.

At switch 6, the operator has to decide whether high head or low head recirculation is required. If high head recirculation is needed, then he continues with switch 6 and skips switch 7. If low head is required, he skips switch 6 and continues with switch 7. Switch 6 causes heat exchanger discharge valves 746 and 747 to close and SI pump suction valves 888A and 888B to open. Switch 7 trips all the SI pumps. Switch 8 closes spray pump test line valve 1813 (if open) and SI pump suction valve 1810 (suction from RWST) which is normally deenergized open. Similar to MOVs 882 and 744, a plant operator must energize it before it can be closed from the control room after the recirculation switchover is completed.

Containment spray recirculation is activated manually. After switchover to core cooling is completed, the operators trip the running spray pump (when the RWST is empty) and close the spray pump isolation valves. In low head recirculation, isolation valves 889A and 889B (at the RHR heat exchanger discharge) are opened and throttle valves 638 and 640 are adjusted until spray flow is established. In high head recirculation, the operator opens MOVs 889A and 889B and verifies 1,300 gpm flow to the spray rings.

Cold leg recirculation is maintained for 24 hours. At this time, the operator realigns the system for combined hot and cold leg recirculation in accordance with the emergency procedure. The two hot leg connections are associated with the SI discharge headers, which are isolated by valves that are normally deenergized and closed. Therefore, assistance is needed from the plant operator to open these valves (i.e., unlock and close the appropriate motor control center breakers for these valves). One of these two hot leg paths needs to be properly aligned for successful hot leg recirculation.

Several parameters relevant to system operation are monitored on the control board. There are redundant level indicators for both sumps. Coolant flow is also indicated for the low head discharge headers, the containment spray headers, and the discharge headers downstream of the SI pumps. Low pressure in the SI pumps suction header is annunciated in the control room.

1.5.2.3.4.2.4 Support Systems, This system includes two emergency core cooling systems, the RHR system, and the SI system. It also uses the same piping and spray rings as the containment spray system. The operator is essential for the activation of this system. Electric power is needed to run pumps and operate valves. Table 1.5.2.3.4-5 gives the power sources to the pumps and valves of this system.

The CCS cools the sump water in the RHR heat exchangers. Pump cooling for the recirculation pumps is essential. If the CCS is not available, the booster pumps (component cooling) can provide sufficient cooling flow. A shaft driven booster pump cools the SI pumps using component cooling water to cool the oil system. RHR pumps can function for several hours without component cooling. Nevertheless, local emergency connections are available to supply city water to these pumps for longer term cooling.

1.5.2.3.4.2.5 Test Requirements. The various emergency core cooling systems used in the recirculation system are tested periodically. Table 1.5.2.3.4-6 lists the description, frequencies, and names of tests performed on each component. Except for the recirculation pumps, all pumps are tested at least every month. The recirculation pumps are tested at every refueling outage. The valves are tested at different intervals. Also, portions of the system are used during heatup and cooldown. The level indicators of the two sumps are tested at every refueling outage. The recirculation switches are also tested during refueling (PT-R13A).

1.5.2.3.4.2.6 Maintenance Requirements. Generally speaking, under normal operating conditions there is no maintenance on the recirculation pumps and the valves associated with recirculation inside the containment.

At any given time, only one of the following components could be unavailable due to maintenance: RHR pumps, SI pumps, auxiliary component cooling pumps, and MOVs 888A, 888B, 885A, and 885B. All valves are included in a preventive maintenance program. In general, one spare SI pump, one spare RHR pump, and associated replacement parts are maintained in inventory to accommodate expeditious exchange or repair when an installed pump becomes inoperable.

1.5.2.3.4.2.7 Technical Specifications. The reactor will not be made critical unless three SI pumps, two RHR pumps, two recirculation pumps, two RHR heat exchangers, and two auxiliary (booster) component cooling pumps, with associated piping and valves, are operable and both RWST low level alarms are operable. The reactor must be shut down if one recirculation pump is out of service or if one SI pump, one RHR pump, or one auxiliary component cooling pump remains out of service for more than 24 hours. It must also be shut down if one RHR heat exchanger remains out of service for more than 48 hours or if one refueling water storage tank low level alarm remains inoperable for more than 7 days. In addition, any valve needed for the system(s) to function during and following accident conditions may be inoperable up to 24 hours provided that all valves which provide a redundant function are demonstrated to be operable.

1.5.2.3.4.3 General Remarks on Logic Models and Quantification.

1.5.2.3.4.3.1 Logic Model. There are two modes of operation for this system: core cooling recirculation and core cooling with containment spray recirculation. The system configuration for core cooling recirculation depends on the type of LOCA. Only the availability of high pressure recirculation is analyzed for a small LOCA. For medium and large LOCAs, low pressure, containment spray, and hot leg recirculation functions must be available. It should be noted that low pressure recirculation means all possible paths of core cooling recirculation (e.g., use of safety injection pumps) in the case of a medium or large LOCA. If low pressure recirculation fails, then containment spray and hot leg recirculation fail also. Thus, four distinct states for the system are defined and discussed separately. These are:

1. High pressure recirculation when injection phase is successful.

2. Low pressure recirculation when injection phase is successful.

3. Containment spray recirculation when low pressure recirculation is available.

4. Hot leg recirculation when low pressure recirculation is available.

Each state is analyzed in a separate section. A fault tree and its minimal cutsets are given first. The fault tree for high head recirculation is shown in Figures 1.6.2.3.4-7 through 1.6.2.3.4-21. The fault tree for low head recirculation is shown in Figures 1.6.2.3.4-22 through 1.6.2.3.4-24, and 1.6.2.3.4-10 through 1.6.2.3.4-21. The fault tree for containment spray recirculation is shown in Figures 1.6.2.3.4-25, and 1.6.2.3.4-9 through 1.6.2.3.4-21. The fault tree for hot leg recirculation is shown in Figures 1.6.2.3.4-26 through 1.6.2.3.4-30, 1.6.2.3.4-11 through 1.6.2.3.4-21. Each fault tree is quantified under different conditions which are transferred from the event trees. These conditions include the availability of the fan coolers, the component cooling system, and the electric buses. Tables 1.6.2.3.4-1 through 1.6.2.3.4-4 summarize the results.

Fault trees including the RHR heat exchangers are constructed. For sequences in which three of five fan coolers are operating, the RHR heat exchangers are not required for successful recirculation system operation. The fan coolers remove sufficient heat to prevent core damage. The effect of the fan coolers will be shown in the quantification sections.

The possibility of using pipe 190, which contains MOV 883 and manual valve 1863, is not specifically included in the fault trees. Its impact on the availability of the system will be included in the quantification sections.

The conditions common to all fault trees are:

- A LOCA has occurred.

- The reactor has been scrammed successfully.

- The injection phase has been successful.
- At least 20 minutes have passed from accident initiation.
- The water in the RWST is at low level alarm point (approximately 96,000 gallons remain in the tank).
- One RHR pump, or one recirculation pump, can provide sufficient flow for both core cooling and containment spray.
- One RHR heat exchanger can provide enough cooling.
- The component cooling system can provide sufficient cooling to the recirculation pumps when the booster pumps are unavailable.
- Mechanical failures in the heat exchangers are not included because their failure mode is very similar to pipe failures, and has a very low frequency. Any significant damage in the heat exchangers would be detected during normal operation by system inventory losses (e.g., RWST or CCS surge tank).

The specific conditions are given later as each fault tree is described.

Test and maintenance contributions are included in the sections on quantification rather than in the fault trees.

1.5.2.3.4.3.2 Fault Tree Coding. Table 1.5.2.3.4-7 is a partial list of basic events, their failure modes, and the corresponding codes.

1.5.2.3.4.3.3 Quantification. In the quantification sections, the unreliability of the system for 24 hours is assessed. The important factors and some unavailability values unique to this system are discussed in this section.

Time is an important factor in two ways: first, the total time of successful operation; and second, the available time for restoration after system failure. Success is defined as adequate core cooling and/or containment pressure control over a 24-hour period. The restoration time is very important to system activation because it defines the time available for an operator to switch over to recirculation phase. This is referred to as "time window" and is defined it as $\tau(t) = t' - t$, where t is the time when the top event occurs and t' is the time of core damage after t. For switchover, t is considered the time when the RWST water level reaches the low level alarm point.

Switchover to the recirculation phase is a dynamic task in which the operators interact with the displays on the control board. The low level alarm from the RWST is a cue to initiate this process. Flow levels are checked to determine if the desired flow path is established.

The human reliability handbook* is used in this study as a guide to quantify the contribution of human error to system unavailability under

*Swain, A. D., and H. E. Guttman, "Handbook of Human Reliability; Analysis With Emphasis on Nuclear Power Plant Applications," NUREG/CR-1278, Sandia Laboratories, Albuquerque, New Mexico.

accident conditions. For the quantification of each human related event the following steps are taken:

1. The failure modes of human error that would lead to adverse situations are identified. System failure is broken down into detailed human error failure modes. Although the state of knowledge on the frequencies of human error under accident conditions may not warrant this detailed quantification effort, it provides a clear picture about the role of human performance on system function. The handbook gives the following reasons for a detailed analytical approach (page 21-11):

    a. The exercise of outlining all plausible modes of operator action decreases the probability of overlooking some important failure path.

    b. Due to the lack of error probability data for nuclear power plant tasks, it is necessary to break down operator actions to a level at which existing data can be used.

    c. The detailed approach makes it easier for analysts making independent estimates to check on the source of any disagreement and to resolve it.

2. The basic human error rate is established based on engineering judgment and frequencies of similar tasks suggested by the handbook (see the chapter on human error rates for a definition for basic human error rate). The most important factor influencing this judgment is the stress level of a particular accident. Skill and control board layout are also important. All the operators at the Indian Point 2 station are trained on a simulator identical to the control board at the plant. Also, the licensed operators practice accident mitigation (especially large LOCA) on this simulator once a year. The controls and instrumentation for switchover are in one general area on the control board.

3. Dependencies among the operators are established in this step (see Section 1.5.1.4, Human Error Rates, for the definitions).

4. The frequency of error for the team of operators is computed using the conditional frequencies suggested by the handbook (see the chapter on human error rates).

5. The results of step 4 are taken as the median frequency. To express the uncertainty in that frequency, an error factor that shows the span from 95th percentile to the median is assigned. The distribution is taken as lognormal and the mean and variance are computed. See the chapter on human error rates for the reasons for choosing this distribution.

In Table 1.5.2.3.4-7, several events are entered under the title of "Noncomponent Events" for which data are not given in Section 1.5.1.1. These events are discussed hereafter.

- ECNTSUMP or ERECSUMP. The containment or recirculation sumps could be plugged by debris during a LOCA. This is judged to be very remote because the strainers cover a large area and more than one screen has to be plugged. Additionally, the entrance water velocities into the pump wells are very low. The median is chosen as 10^{-6} (judgmentally) and the error factor as 100. The mean and variance of lognormal distribution become:

  Mean: 5.0×10^{-5}

  Variance: 6.4×10^{-6}

- HDISCHDN. The SI portion of the system is treated as an entity in one of the fault trees. This event is the failure of two out of three SI pumps to align to the proper position for high head injection. From the section on high pressure injection system, the following mean (combination of supercomponents B, C, and D in that section) is obtained:

  Mean: 1.6×10^{-4}

  Variance: 2.0×10^{-8}

- ELOHDDIS. The low pressure injection system is treated similarly to the SI system. The failure is unsuccessful alignment of the discharge paths for low pressure injection. The section on the low pressure injection system gives the mean (α_{EF} in that section):

  Mean: 6.5×10^{-6}

  Variance: 5.3×10^{-11}

1.5.2.3.4.3.4 Piping Analysis. Table 1.5.2.3.4-8 shows the pipe failure analysis. There is no single pipe section failure that would totally disable one of the functions. In most cases, pipe failure can be detected during normal operation through RWST level indicators. If pipe 361 (the connecting line between the RHR heat exchangers and low head injection headers) fails, the SI pumps could be used after the broken line is isolated. If pipe 60 fails, then the return line around the RHR pumps can be used. MOV 883 and manual valve 1863 would be opened, and MOV 882 and manual valve 846 would be closed. Also, depending on the location of pipe failure (pipe 60), manual valve 898 may need to be opened, and MOV 887A or 887B may need to be closed. Fan cooler availability is essential in this mode because the heat exchangers are bypassed.

1.5.2.3.4.4. High Pressure Recirculation.

1.5.2.3.4.4.1 Fault Tree. The fault tree is shown in Figures 1.5.2.3.4-7 through 1.5.2.3.4-17 and 1.5.2.3.4-26 through 1.5.2.3.4-29. The top event is "High Pressure Recirculation Fails to Provide 300 gpm for 24 Hours." In addition to those mentioned in Section 1.5.2.3.4.3, the fault tree is based on the following conditions:

- Small LOCA has occurred.
- High pressure coolant injection has been completed successfully by the SI pumps. Therefore, only pump failures are considered. This means that inadvertent blockage of flow is discounted.
- One high head pump is sufficient for adequate core cooling.
- The MOV 744 should be opened from a closed position if it is needed. This is a conservative assumption because MOV 744 is deengergized open and may not be reenergized and closed until the recirculation switchover is complete.

Table 1.5.2.3.4-9 gives the minimal cutsets with one and two basic events, with the house events treated as basic events. Failure of pipe 60 (HPPLN60E) will fail the high head recirculation. This is because, in this fault tree, the heat exchanger bypass through pipe 190 has not been included. However, the effect of this pipe is taken into consideration in quantification. The loss of power to motor control center bus 26B (JBS226BD) will fail the system by failing MOVs 747 and 822B, given that the fan coolers are not available and the containment spray recirculation is not activated. Containment spray recirculation would put colder water back into the sump, thus providing heat removal from the system. As an additional conservatism, this use of containment spray recirculation has not been included in the quantification because its inclusion would not have a significant impact.

This fault tree is quantified under several conditions depending on the availability of fan coolers, component cooling water system, and three electrical divisions. Table 1.5.2.3.4-1 gives all possible combinations of these conditions.

1.5.2.3.4.4.2 Quantification.

1.5.2.3.4.4.2.1 All electric buses and component cooling available; fan coolers unavailable. Table 1.5.2.3.4-10 gives the cause table. Each item in this table is discussed hereafter.

1.5.2.3.4.4.2.1.1 Human error contributions. The frequency of operator failure to establish high pressure recirculation is evaluated here. In a small LOCA, the time for switchover to the recirculation phase is definitely more than 2 hours after the accident. More likely, it is around 10 hours. The time window for switchover is at least 60 minutes. This is relatively long and would allow the operators to take corrective actions in case of component failures and human error. This is particularly true for the RHR pumps, which can be aligned for containment sump

recirculation. Also, the stress level on the operators should be moderately high; that is, higher than during normal operating conditions but significantly less than during a large LOCA.

Four people would be in the control room by this time. Two of the four are control board operators, and at least one of them has a senior reactor operator's (SRO) license. The remaining two are the watch supervisor who has an SRO license and shift technical advisor. The shift technical advisor does not have an operating license, but has been trained in the mechanics of accident control and plant response characteristics.

The two operators would be doing the switchover. One would be reading the procedures and the other would be operating the controls. The watch supervisor would be monitoring the process while checking other parts of the control board. The shift technical advisor would not be involved in the detail. He is supposed to form an independent interpretation of the instrumentation readout. The Three Mile Island scenario (i.e., many people in the control room and frequent outside telephone calls) would not happen because of special corrective actions mandated by the Nuclear Regulatory Commission.

Three stages are defined for the switchover process. In the first stage, the operators follow the RWST level. This ends when the decision is made to initiate the switchover. Errors at this stage (i.e., failure to decide to initiate switchover) may fail the system and should be attributed to all four operators. During the second stage, the switchover is performed. Here, errors would be caused by the two operators at the control board. The third stage starts when switchover is completed. All four operators would be looking at the indicators to see if the switchover was successful. Earlier errors can be discovered and corrected at this stage.

Two operator related events that could lead to system failure are identified. These are:

1. Failure to initiate switchover.

2. Switch 7 is turned to the "On" position and no corrective actions are taken.

Three things help the operators to recognize that switchover should be initiated. First, operator training will condition them to recognize switchover requirements. Second, the procedures would lead the operators to switchover. Third, the RWST low level alarm would alert the operators.

A small LOCA may impose a moderately high stress level. Sandia Laboratories' human reliability handbook suggests that the stress level may even become very high (page 17-18):

> A LOCA is a special case. Presumably a small or slowly developing LOCA should not be accompanied by more than a moderately high level of stress for most people. Of

course, in some incidents involving small LOCAs, the initial stress level may not be very high, but subsequent events may raise the stress level. For example, some operating personnel in the TMI accident, which involved a small LOCA, were considered subject to high levels of stress at various times by the interviewers on the Kemeny Commission (Kemeny, 1979) and Rogovin Special Inquiry Group (Rogovin and Frampton, 1980).

The basic human error frequencies must be estimated using judgment because there is no statistical data. The handbook suggests some adjusting factors (page 17-18):

> We can find no objective data from which to derive the factors to apply to human error probabilities (HEPs) and uncertainty bounds for the condition of a moderately high level of stress. On the basis of judgment, we multiply the HEP and uncertainty bounds for step-by-step, rule-based tasks performed under optimal stress levels by 2, and for tasks requiring dynamic interplay between the operator and system indications, we use a multiplier of 5.

For errors of omission (the first event is of this kind) the handbook makes the following suggestions (Table 20-15, page 20-33):

TASK	Human Error Frequency--Best Estimate (lower bound "to" upper bound)
Omit an item when preparing a list of values or set of tags.	.003 (.001 to .01)
Failure to carry out a specific oral instruction to change or restore a valve.	.001 (.0005 to .005)
Failure to initiate level 1 tagging.	.001 (.0005 to .005)
Failure to follow established procedure or policies in valve changes or restoration.	.01 (.005 to .05)

Based on these arguments and suggestions and on those given in Section 1.5.2.3.4.3.3, 6×10^{-3} is chosen as the median for the basic human error frequency and 1×10^{-3} and 3×10^{-2} as the 5th and 95th percentiles, respectively.

The dependencies among the operators are high dependence between the two reactor operators, moderate dependence between the watch supervisor and the first two reactor operators, moderate dependence between the shift technical advisor and the rest of the personnel in the control room. The two reactor operators would be interacting closely. Therefore,

there would be high dependence between them. The watch supervisor (an SRO) is less dependent on the first two operators because he may not become involved in the detail. The dependency level of the shift technical advisor is not clear. He may be highly dependent on the others because he is part of the team and would follow the same line of thought. On the other hand, because he does not have to become involved in the detail, he may interpret the indicators rather independently. An average shift technical advisor is judged to be moderately dependent on the rest of the team.

Using the formulas recommended in the handbook, error frequency of the four person team for this task (initiation of switchover) would be

$$6.0 \times 10^{-3} \times \left(\frac{1 + 6 \times 6 \times 10^{-3}}{7}\right)^2 \times \frac{1 + 6 \times 10^{-3}}{2} = 6.6 \times 10^{-5}$$

An error factor of 20 is assigned. The mean and variance become:

Mean: 3.46×10^{-4}

Variance: 3.19×10^{-6}

For the second event, the operators erroneously turn switch 7 to the "On" position which stops all the SI pumps. However, it is possible to restore these pumps from the control board. The former may occur as a result of the error of two the operators (i.e., one reading the procedure and the other manipulating the controls). This error may be discovered by the watch supervisor or shift technical advisor while the switchover is in progress or by the whole team after switchover is completed. It is more likely that the first two operators would not discover their own error. Also, the watch supervisor and shift technical advisor would be highly dependent on each other. A point value for the frequency of turning switch 7 and not recovering the error is:

$$\text{fr}\begin{pmatrix}\text{Switch 7}\\ \text{"On"}\end{pmatrix} \quad \text{fr}\begin{pmatrix}\text{No recovery}\\ \text{SI pumps not}\\ \text{started manually}\end{pmatrix}$$

$$= \left(6.0 \times 10^{-3} \times \frac{1 + 6 \times 10^{-3}}{2}\right) \left(6.0 \times 10^{-3} \times \frac{1 + 6 \times 10^{-3}}{2}\right)$$

$$= 9.0 \times 10^{-6}$$

This is taken as the median and assigned an error factor of 20. The mean and variance for a lognormal distribution become:

Mean: 4.72×10^{-5}

Variance: 5.93×10^{-8}

High head recirculation may also fail due to a combination of human error and other causes. The recirculation pumps may fail due to human error (i.e., during maintenance) on manual valves 753A, 753B, 753G, or 753H. The RHR pumps have to be aligned manually from the control room to provide the recirculation flow when the recirculation pumps are not available.

The booster pumps are flow checked after maintenance or every month. Therefore, the position of manual valves 753A, 753B, 753G, or 753H is checked regularly. If one of these valves is in the closed position, failure of both recirculation pumps would result. Under normal operating conditions, these valves are never manipulated. The unavailability of these valves should be on the order of 10^{-6}.

The operators can switch to RHR pumps and establish the recirculation flow from the containment sump if there is no flow from the recirculation pumps. They also have to reset recirculation switch 3. The median frequency of failure for one operator to recognize this mode of operation is judged to be 0.1. The stress level for this action could be high because of multiple failures in the recirculation pump section. With high and moderate dependencies among the operators, the watch supervisor, and the shift technical advisor, the following is obtained:

$$\text{Point Value:} \quad 0.1 \times \left(\frac{1 + 6 \times 0.1}{7}\right)^2 \times \frac{1 + 0.1}{2} = 2.9 \times 10^{-3}$$

This is taken as the median. An error factor of 20 reflects the degree of uncertainty. The mean and variance for the resulting lognormal distribution are:

Mean: 1.52×10^{-2}

Variance: 6.16×10^{-3}

In case of failures in the train consisting of heat exchanger 21 (and not the heat exchanger failure itself) and the adjacent valves, the operators should open MOVs 746 and 747 to establish flow from heat exchanger 22 to the suction side of the SI pumps. The frequency distribution of failure to switch to RHR pumps is also assigned to this failure mode.

1.5.2.3.4.4.2.1.2 <u>Single hardware failures</u>. The only single element cutsets are:

- HPPLN60E: pipe 60 rupture.
- JBS226BD: electric bus 26B failure (given that containment spray recirculation is not activated).

The failure of pipe 60 would fail high head recirculation. The maximum time that this failure would stay undetected is conservatively judged to

be 1 week. From Section 1.5.1.1, pipe failure rate (mean) is 8.6×10^{-10} per hour. Failure frequency of pipe 60 is:

Mean: $8.6 \times 10^{-10} \times 24 \times 7 \times 1/2 = 1.44 \times 10^{-7}$

Variance: $(1/2 \times 24 \times 7)^2 \times 6.0 \times 10^{-17} = 4.2 \times 10^{-13}$

The mean and variance of the failure rate of motor control center bus 26B are:

Mean: 1.90×10^{-6}

Variance: 5.75×10^{-11}

This failure mode can be bypassed by opening MOV 889A. This would remove the heat from the sump water by cooling it in heat exchanger 22 and spraying it back into the containment. It is conservatively assumed that this mode of operation would not be used.

1.5.2.3.4.4.2.1.3 Multiple hardware failures. The double and triple failure contributions are derived using the computer code RAS. This code orders minimal cutsets according to their degree of contribution to the frequency of the top event. The first few cutsets that contribute more than 90% to the frequency of the top event are checked for repeated component types. The contribution of human error to partial system failure is also included. Some hardware failure frequencies are adjusted to reflect these errors.

In case of failures in the recirculation pump section, the operators would use the RHR pumps. The frequency of failure to switch to RHR pumps due to operator error is computed in Section 1.5.2.3.4.4.2.1.1. The mean and variance are:

Mean: 1.52×10^{-2}

Variance: 6.16×10^{-3}

This frequency is assigned to check valve 741 in the input to RAS. The same frequencies are used for operator error to switch to heat exchanger 22 when heat exchanger 21 is unavailable (e.g., MOV 822B does not open). For this, the operators must open both MOVs 746 and 747. The frequency of MOV 638 is adjusted to reflect operator error also.

The mean frequency of the cutsets with repeated component types is adjusted. The following minimal cutsets contained these events:

- EPMRC22S EPMRC21S ECV-741C

  If both recirculation pumps fail and operators fail to switch to RHR pumps (represented by ECV-741C), then the system will be unavailable. The unreliability of one recirculation pump is the sum of two

contributors: failure during operation and failure to start. The mean and variance become:

Mean: $1.95 \times 10^{-5} \times 24 + 6.41 \times 10^{-3} = 6.87 \times 10^{-3}$

Variance: $1.60 \times 10^{-7} \times (24)^2 + 7.78 \times 10^{-6} = 1.00 \times 10^{-4}$

The mean of the frequency of both recirculation pumps failing is:

Mean: $(6.87 \times 10^{-3})^2 + 1.00 \times 10^{-4} = 1.47 \times 10^{-4}$

Operator failure frequency is assigned to ECV-741C. The mean of the frequency of this minimal cutset becomes:

Mean: $1.47 \times 10^{-4} \times 1.52 \times 10^{-2} = 2.24 \times 10^{-6}$

- HPMSI21S HPMSI22S HPMSI23S

The unreliability of one SI pump is the sum of two of these unreliability contributors, failure during operation and failure to start. The mean and variance become:

Mean: $1.59 \times 10^{-5} \times 24 + 6.41 \times 10^{-3} = 6.76 \times 10^{-3}$

Variance: $1.61 \times 10^{-8} \times (24)^2 + 7.78 \times 10^{-6} = 1.73 \times 10^{-5}$

The mean and variance of the frequency of all three pumps failing in 24 hours are (using DPD arithmetic):

Mean: 2.8×10^{-6}

Variance: 1.0×10^{-10}

- HMV888AQ HMV888BQ

The mean and variance of the frequency of failure of an MOV to open are (from Section 1.5.1.1):

Mean: 2.30×10^{-3}

Variance: 1.20×10^{-6}

The mean and variance of both valves failing are:

Mean: $(2.30 \times 10^{-3})^2 + 1.20 \times 10^{-6} = 6.57 \times 10^{-6}$

Variance: 5.57×10^{-11}

This is a conservative measure because the valves can be opened manually within the available time window.

The system diagram was inspected and it was concluded that minimal cutsets with four or more elements do not contribute significantly to the top event. The results of this section are summarized in Table 1.5.2.3.4-10.

1.5.2.3.4.4.2.1.4 Maintenance contribution. Section 1.5.2.3.4.3.1 gives the list of components that could be unavailable due to maintenance when the system is activated. Only the SI pumps are main contributors because the unavailability of RHR related components due to operator error is much larger than the maintenance related unavailability. Additionally, the auxiliary component cooling pumps do not appear in any of the minimal cutsets because the component cooling system is available. The mean and variance of the unavailability of the SI pumps due to maintenance are (from Section 1.5.1.3):

Mean: 1.15×10^{-3}

Variance: 1.03×10^{-7}

System failure occurs if all three pumps are unavailable. The unavailability of two SI pumps due to hardware failure is computed using a lognormal distribution. The mean and variance are:

Mean: $(6.76 \times 10^{-3})^2 + 1.73 \times 10^{-5} = 6.30 \times 10^{-5}$

Variance: 1.04×10^{-8}

System failure frequency due to SI pump maintenance becomes

Mean: $3 \times 1.15 \times 10^{-3} \times 6.30 \times 10^{-5} = 2.17 \times 10^{-7}$

1.5.2.3.4.4.2.1.5 Other causes. The system has several minimal cutsets in one compartment. The effects of external causes, fire, or flood are discussed elsewhere in this study.

Other causes such as errors in manufacture, installation, and design are judged to be of low frequencies because most of the system has been tested frequently. The β-factor is used to express these causes. The range for a β is chosen as 10^{-3} to 5×10^{-2}, which yields a mean and variance of:

Mean: 1.4×10^{-2}

Variance: 6.1×10^{-4}

The same β-factor is used for valves and pumps. The frequency of all three SI pumps failing (using β-factor) is

Mean: $1.4 \times 10^{-2} \times 6.76 \times 10^{-3} = 9.46 \times 10^{-5}$

The frequency of both MOVs 888 or both MOVs 822 failing to open (using β-factor) is

Mean: $1.4 \times 10^{-2} \times 2.30 \times 10^{-3} = 3.20 \times 10^{-5}$

The frequency of both recirculation pumps or both MOVs 1802 failing to operate (using β-factor) is

Mean: $1.4 \times 10^{-2} (6.87 \times 10^{-3} + 2.30 \times 10^{-3}) = 1.29 \times 10^{-4}$

System failure will occur if RHR pumps are not realigned. Then,

Mean: $1.29 \times 10^{-4} \times 1.52 \times 10^{-2} = 1.96 \times 10^{-6}$

1.5.2.3.4.4.2.1.6 System unreliability. Table 1.5.2.3.4-10 shows the results that have been derived for the mean values of the contributors to high head recirculation unavailability when the fan coolers are unavailable, and component cooling and all electric buses are available. Only the main contributors are used for uncertainty analysis. The mathematical expression for the unreliability of the system is written in terms of unreliabilities or unavailabilities of dominant contributors. The human error distributions share the same state of knowledge. Therefore, they are expressed as a constant times a distribution.

$$Q_{HIGH\ HEAD} = Q_{H1} + 0.136Q_{H1} + Q_{MCC} + Q_{MOV}(43.93Q_{H1}) + Q_{SI}^3 + 4Q_{MOV}^2 + 3Q_{SIM}\,Q_{SI}^2 + BQ_{SI} + 4BQ_{MOV}$$

where

Q_{H1}: Human error, failure to initiate switchover;

$\alpha = 3.46 \times 10^{-4}$, $\beta^2 = 3.19 \times 10^{-6}$.

Q_{MCC}: Loss of power in MCC Bus 26B:

$\alpha = 1.9 \times 10^{-6}$, $\beta^2 = 5.75 \times 10^{-11}$

Q_{MOV}: MOV fails to operate:

$\alpha = 2.32 \times 10^{-3}$, $\beta^2 = 1.19 \times 10^{-6}$.

Q_{SI}: Unreliability of an SI pump in 24 hours:

$\alpha = 6.76 \times 10^{-3}$, $\beta^2 = 1.73 \times 10^{-5}$

Q_{SIM}: Maintenance on SI pumps:

$\alpha = 1.15 \times 10^{-3}$, $\beta^2 = 1.03 \times 10^{-7}$

B: β-factor:

$\alpha = 1.4 \times 10^{-2}$, $\beta^2 = 6.1 \times 10^{-4}$

Using DPD arithmetic, we find for $Q_{HIGH-HEAD}$:

Mean:	6.8×10^{-4}
Variance:	1.04×10^{-6}
5th Percentile:	5.0×10^{-5}
95th Percentile:	1.8×10^{-3}
Median:	4.2×10^{-4}

1.5.2.3.4.4.2.2 Fan coolers and electric bus 5A unavailable; component cooling and electric buses 2A, 3A, and 6A available. Loss of electric bus 5A before safeguards actuation causes the failure of SI pump 21, recirculation pump 21, MOVs 888A, 822A, 885A, 746, and 1802A. Since 885A is inoperable, recirculation via the RHR pumps is not possible unless this valve is opened manually. Table 1.5.2.3.4-11 gives the cause table. Each item in this table is discussed hereafter.

1.5.2.3.4.4.2.2.1 Human error contributions. The frequency of operator failure to establish high head recirculation is evaluated in Section 1.5.2.3.4.4.2.1.1. The same results also apply here. Loss of electric bus 5A would not have significant effect on operator error rates because of a long time window.

1.5.2.3.4.4.2.2.2 Single hardware failures. The dominant single element cutsets are:

- HPPLN60E: pipe 60 rupture; mean = 1.44×10^{-7}
- JBS226BD: MCC bus 26B failure; mean = 1.90×10^{-6}
- MOV 822B fails to open; mean = 2.30×10^{-3}

The first two are quantified in Section 1.5.2.3.4.4.2.1.2. The failure of DC control power to 480V bus 6A causes recirculation pump 22 and SI pump 23 to fail to start. The mean and variance of the failure frequency are:

Mean:	2.74×10^{-8}
Variance:	2.96×10^{-14}

The mean and variance of the remaining single events are computed or referenced in Section 1.5.2.3.4.4.2.1.3.

1.5.2.3.4.4.2.2.3 Multiple hardware failures. The following multiple failures would lead to system failure:

- Recirculation pump 22 fails to run (mean = 6.87×10^{-3}) and the operators fail to open MOV 885A manually and align the RHR pumps for recirculation cooling.

- MOV 1802B fails to open (mean = 2.32×10^{-3}) and the operators fail to open MOV 885A manually and align the RHR pumps for recirculation cooling.

- Manual valves 753A, 753B, 753G, or 753H transfer closed (mean = 7.4×10^{-8}) and the operators fail to open MOV 885A manually and align the RHR pumps for recirculation cooling.

- MOV 888B fails to open (mean = 2.31×10^{-3}) and the operators fail to open MOV 888A or 888B manually.

- Both SI pumps fail.

The frequency of human error portions of the first four events is judged to be lognormally distributed with median at 0.1 and error factor 3. The mean and variance are:

Mean: 1.25×10^{-1}

Variance: 8.78×10^{-3}

Thus the mean frequency of the first event is

Mean: $6.87 \times 10^{-3} \times 1.25 \times 10^{-1} = 8.6 \times 10^{-4}$

The mean frequency of system failure due to MOV 1802B or 888B failure and no recovery is

Mean: $2.30 \times 10^{-3} \times 1.25 \times 10^{-1} = 2.9 \times 10^{-4}$

The frequency of the fourth event is less than 10^{-7}.

The frequency of the last event, that is, the failure of both SI pumps, is computed in Section 1.5.2.3.4.4.2.1.4. The mean and variance are:

Mean: 6.30×10^{-5}

Variance: 1.04×10^{-8}

The contribution of other multiple hardware failures to system unavailability is very small.

1.5.2.3.4.4.2.2.4 Maintenance contribution. If one SI pump is under maintenance and the other failed due to hardware failures, high head recirculation would be unavailable. The mean for system unavailability becomes (see Section 1.8.1.3 for data)

Mean: $2 \times 1.15 \times 10^{-3} \times 6.76 \times 10^{-3} = 1.55 \times 10^{-5}$

1.5.2.3.4.4.2.2.5 Other Causes. Except for the SI pumps, the discussions given in Section 1.5.2.3.4.4.2.1.5 do not apply here because only one of the redundant trains is available. The resulting mean of the frequency of both SI pump failures due to other causes becomes

Mean: $1.4 \times 10^{-2} \times 6.76 \times 10^{-3} = 9.46 \times 10^{-5}$

1.5.2.3.4.4.2.2.6 System unreliability. Table 11 shows the results that have been derived for the mean values of the contributors to high head recirculation unavailability when the fan coolers and electric bus 5A are unavailable and component cooling and electric buses 2A, 3A, and 6A are available. Only the main contributors are addressed in the uncertainty analysis. The mathematical expression for the unreliability of the system in terms of the unreliabilities or unavailabilities of dominant contributors is

$$Q_{HIGH\ HEAD} = Q_{H1} + 0.136Q_{H1} + Q_{MCC} + Q_{MOV} + Q_{RC}Q_{H2} + 2Q_{MOV}Q_{H2}$$

$$+ Q_{SI}^2 + 2Q_{SIM}\,Q_{SI} + BQ_{SI}$$

The terms are defined in Section 1.5.2.3.4.4.2.1.6 except for the following:

Q_{RC}: Unreliability of a recirculation pump in 24 hours:

$\alpha = 6.87 \times 10^{-3}$, $\beta^2 = 1.40 \times 10^{-4}$

Q_{H2}: Human error in opening MOV 885A manually and shifting to RHR pumps or human error in manually opening MOV 888A or MOV 888B:

$\alpha = 0.125$, $\beta^2 = 8.78 \times 10^{-3}$

The results of DPD arithmetic for the unreliability of high head recirculation are:

Mean:	4.3×10^{-3}
Variance:	4.0×10^{-6}
5th Percentile:	1.6×10^{-3}
95th Percentile:	7.9×10^{-3}
Median:	3.6×10^{-3}

1.5.2.3.4.4.2.3 Fan coolers and electric bus 6A unavailable; component cooling and electric buses 2A, 3A, and 5A available. Loss of electric bus 6A at or before safeguards actuation causes the failure of SI pump 23, recirculation pump 22, RHR pump 22, MOVs 888B, 822B, 747, 885B, and 1802B. Since MOVs 822B and 747 are inoperable, sump water entering the core cannot be cooled down. Since the fan coolers are unavailable, high head recirculation failure is conservatively assumed to be a certainty. If containment spray recirculation is activated, it can put colder water back into the sump, thus providing heat removal from the system. However, as stated earlier, this has not been included in the quantification.

1.5.2.3.4.4.2.4 Fan coolers and electric buses 2A and 3A unavailable; component cooling and electric buses 5A and 6A available. Loss of electric buses 2A and 3A at or before safeguards actuation cause the

failure of SI pump 22 and RHR pump 21. This is very similar to the situation in Section 1.5.2.3.4.4.2.1. The only differences in the results are introduced through the SI pump unavailability due to multiple hardware failures and maintenance plus hardware failure. Table 1.5.2.3.4-12 gives the cause table.

The mean and variance of the frequency of hardware failure of both SI pumps 21 and 23 are (see Section 1.5.2.3.4.4.2.1.4):

Mean: 6.30×10^{-5}

Variance: 1.04×10^{-8}

The mean of the unavailability of both SI pumps due to maintenance and hardware failure becomes

Mean: $2 \times (1.15 \times 10^{-3} \times 6.76 \times 10^{-3}) = 1.50 \times 10^{-5}$

System unreliability is computed by the following expression which is in terms of the dominant contributors (see Table 1.5.2.3.4-12):

$$Q_{HIGH\ HEAD} = Q_{H1} + 0.136Q_{H1} + Q_{MCC} + Q_{MOV}\ (43.93Q_{H1}) + 4Q_{MOV}^2 + Q_{SI}^2$$

$$+ 2Q_{SIM}\ Q_{SI} + B\ Q_{SI} + 4B\ Q_{MOV}$$

The terms are defined in Section 1.5.2.3.4.4.2.1.6. Using DPD arithmetic, the characteristic values of $Q_{HIGH\ HEAD}$ are obtained:

Mean: 7.55×10^{-4}

Variance: 1.05×10^{-6}

5th Percentile: 8.30×10^{-5}

95th Percentile: 1.90×10^{-3}

Median: 4.80×10^{-4}

1.5.2.3.4.4.2.5 Fan coolers and electric buses 2A, 3A, and 5A unavailable; component cooling and electric bus 6A available. Except for SI pump 21 and RHR pump 21, the components that may remain available under these conditions are the same as those given in Section 1.5.2.3.4.4.2.3. The mathematical expression for system unreliability becomes

$$Q_{HIGH\text{-}HEAD} = Q_{H1} + 0.136Q_{H1} + Q_{MCC} + Q_{RC} + 3Q_{MOV} + Q_{SI} + Q_{SIM}$$

Compare this with Section 1.5.2.3.4.4.2.2.6. All the terms are defined in Sections 1.5.2.3.4.4.2.1.6 and 1.5.2.3.4.4.2.2.6. Using DPD arithmetic, the characteristic values of $Q_{HIGH\ HEAD}$ are obtained:

Mean:	2.21×10^{-2}
Variance:	1.14×10^{-4}
5th Percentile:	9.70×10^{-3}
95th Percentile:	3.80×10^{-2}
Median:	1.90×10^{-2}

1.5.2.3.4.4.2.6 Other conditions when fan coolers are unavailable. If the electric buses 2A, 3A, and 6A, or 5A and 6A, or 2A, 3A, 5A, and 6A are unavailable, then system failure is a certainty. The same is also true when component cooling is unavailable.

1.5.2.3.4.4.2.7 Fan coolers, all electric buses, and component cooling available. The only difference between this case and that in Section 1.5.2.3.4.4.2.1 is that heat exchanger availability is not addressed here. In this case, component cooling affects the system only through the recirculation pumps. Table 1.5.2.3.4-13 gives the cause table.

1.5.2.3.4.4.2.7.1 Human error contributions. The frequency of operator failure to activate high pressure recirculation is given in Section 1.5.2.3.4.4.2.1.1. Fan cooler availability does not have any effect on this probability distribution.

1.5.2.3.4.4.2.7.2 Single hardware failures. The only single element cutset is HPPLN60E. The mean and variance of the frequency for this cutset were obtained in Section 4.2.1.2:

Mean:	1.4×10^{-7}
Variance:	4.2×10^{-13}

If pipe 190 is opened and pipe 60 is isolated, the failure of the latter would be bypassed. The median frequency of failure to accomplish this bypass is judged to be 0.1 and the error factor is judged to be 3. The mean and variance become:

Mean:	0.12
Variance:	8.8×10^{-3}

The mean and variance of system failure due to a failure in pipe 60 are obtained:

Mean:	$1.4 \times 10^{-7} \times 0.12 = 1.7 \times 10^{-8}$
Variance:	1.0×10^{-14}

1.5.2.3.4.4.2.7.3 Multiple hardware failures. In Section 1.5.2.3.4.4.2.1.3 a method for identifying the main contributors to multiple hardware failures is given. The same approach is also used here. Similarly, operator error in switchover to RHR pumps (when recirculation pumps are failed) is incorporated in the input data to the RAS code, and the frequency of minimal cutsets with repeated components is corrected. The significant minimal cutsets are given in Table 1.5.2.3.4-13. The frequency of one minimal cutset is adjusted to incorporate the possibility of using pipe 190.

- HMV888AQ HMV888BQ

  In Section 1.5.2.3.4.4.2.1.3, the mean and variance of the frequency of two valves failing to open were obtained:

  Mean: 6.57×10^{-6}

  Variance: 1.46×10^{-11}

  This failure is similar to failure of pipe 60, therefore, credit should be given to the fact that it may be bypassed through pipe 190. In Section 1.5.2.3.4.4.2.7.2, it was concluded that the mean and variance of the frequency of failure in using pipe 190 are:

  Mean: 0.12

  Variance: 8.8×10^{-3}

  The frequency of system failure yields

  Mean: $0.12 \times 6.57 \times 10^{-6} = 7.88 \times 10^{-7}$

1.5.2.3.4.4.2.7.4 Maintenance contribution. This case is similar to that in Section 1.5.2.3.4.4.2.1.4 in which only two sets of components are the main contributors: the SI pumps and MOVs 888A and 888B. The mean frequency of system failure due to maintenance on SI pumps is the same as that obtained in Section 1.5.2.3.4.4.2.1.4:

Mean: 2.10×10^{-7}

1.5.2.3.4.4.2.7.5 Other causes. The results of Section 1.5.2.3.4.4.2.1.5 apply here also, except that only one pair of valves should be considered in this case.

1.5.2.3.4.4.2.7.6 System unreliability. The mathematical expression for high head recirculation when fan coolers, component cooling, and all electrical buses are available is written here in terms of the dominant contributors (see Table 1.5.2.3.4-13)

$$Q_{HIGH\text{-}HEAD} = Q_{H1} + 0.136Q_{H1} + Q_{SI}^3 + Q_{MOV}^2\, Q_{H4} + 3\, Q_{SIM}\, Q_{SI}^2 + B\, Q_{SI} + B\, Q_{MOV}\, Q_{H4}$$

The variables are defined in Section 1.5.2.3.4.4.2.1.6 except for

Q_{H4}: Failure to establish recirculation flow through pipe 190.

$\alpha = 0.12$; $\beta^2 = 8.8 \times 10^{-3}$

DPD arithmetic on $Q_{HIGH\ HEAD}$ gives:

Mean:	4.93×10^{-4}
Variance:	8.76×10^{-7}
5th Percentile:	2.00×10^{-5}
95th Percentile:	1.20×10^{-3}
Median:	1.80×10^{-4}

1.5.2.3.4.4.2.8 Electric bus 6A unavailable; fan coolers, component cooling, and electric buses 2A, 3A, and 5A available. Loss of electric bus 6A at or before safeguards actuation causes the failure of SI pump 23, recirculation pump 22, and MOVs 888B, 885B, 747, and 1802B. This is similar to the conditions in Section 1.5.2.3.4.4.2.2 except that the availability of MOV 822A or 822B does not affect the top event. Table 1.5.2.3.4-14 gives the cause table for this case. It is very similar to Table 1.5.2.3.4-11.

The mathematical expression for system unreliability in terms of the main contributors is

$$Q_{HIGH\ HEAD} = Q_{H1} + 0.136Q_{H1} + Q_{MCC}Q_{H4} + Q_{RC}Q_{H2} + 2Q_{MOV}Q_{H2} + Q_{SI}^2 + 2Q_{SIM}Q_{SI} + BQ_{SI}$$

The results of DPD arithmetic on this expression are:

Mean:	2.0×10^{-3}
Variance:	2.7×10^{-6}
5th Percentile:	3.7×10^{-4}
95th Percentile:	5.4×10^{-3}
Median:	1.4×10^{-3}

1.5.2.3.4.4.2.9 Electric bus 5A unavailable; fan coolers, component cooling, and electric buses 2A, 3A, and 6A available. Loss of electric bus 5A at or before safeguards actuation causes the failure of SI pump 21, recirculation pump 21, and MOVs 888A, 885A, 746, and 1802A. This is very similar to the conditions in Section 1.5.2.3.4.4.2.8. Table 1.5.2.3.4-15 gives the cause table for this case. System unreliability is also given in Section 1.5.2.3.4.4.2.8.

1.5.2.3.4.4.2.10 Electric buses 2A and 3A unavailable; fan coolers, component cooling, and electric buses 5A and 6A available. Section 1.5.2.3.4.4.2.4 discusses a similar case with the fan coolers unavailable. Table 1.5.2.3.4-12 applies here also except that heat exchanger related entries should be taken out and the possibility of using pipe 190 should be incorporated. Table 1.5.2.3.4-16 is the result. The mathematical expression for system unreliability is

$$Q_{HIGH\ HEAD} = Q_{H1} + 0.136Q_{H1} + Q_{MOV}^2\, Q_{H4} + Q_{SI}^2 + 2Q_{SIM}\, Q_{SI} + BQ_{SI} + BQ_{MOV}\, Q_{H4}$$

The terms are defined in Section 1.5.2.3.4.4.2.1.6. A DPD arithmetic on $Q_{HIGH\ HEAD}$ gives:

Mean:	6.03×10^{-4}
Variance:	9.02×10^{-7}
5th Percentile:	5.10×10^{-5}
95th Percentile:	1.30×10^{-3}
Median:	2.70×10^{-4}

1.5.2.3.4.4.2.11 Other conditions when fan coolers and component cooling are available. If electric buses 5A and 6A or 2A, 3A, 5A, and 6A are unavailable, then system failure is a certainty. If electric buses 2A, 3A, and 6A (or electric buses 2A, 3A, and 5A) are unavailable, then a sufficient number of fan coolers cannot be available.

1.5.2.3.4.4.2.12 Component cooling unavailable; fan coolers available. When the fan coolers are available, component cooling appears only in relation to the recirculation pump cooling. The auxiliary component cooling pumps are a backup to the main CCS loop. The failure frequencies are given in Section 1.5.1.1. The mean and variance of the unreliability of one pump in 24 hours are:

Mean: $1.68 \times 10^{-5} \times 24 + 6.41 \times 10^{-3} = 6.78 \times 10^{-3}$

Variance: $2.76 \times 10^{-8} \times (24)^2 + 7.78 \times 10^{-6} = 2.37 \times 10^{-5}$

The mean and variance of the unreliability of both pumps become:

Mean: $(6.78 \times 10^{-3})^2 + 2.65 \times 10^{-5} = 7.25 \times 10^{-5}$

Variance: 2.7×10^{-8}

This unreliability is due to hardware failures. For causes other than this, the β-factor approach is applied (see Section 1.5.2.3.4.4.2.1.5 for details). The mean of this contribution becomes

Mean: $0.014 \times 6.78 \times 10^{-3} = 9.5 \times 10^{-5}$

These frequencies are an order of magnitude less than the total frequencies given in Tables 1.5.2.3.4-13 through 1.5.2.3.4-15. Therefore, the effect of component cooling availability can be dropped from the analysis when the fan coolers are available.

1.5.2.3.4.5. Low Pressure Recirculation.

1.5.2.3.4.5.1 Fault Tree. The top event is "Low Pressure Recirculation Fails to Provide 600 gpm for 24 Hours." Figures 1.5.2.3.4-19 through 1.5.2.3.4-21, 1.5.2.3.4-10 through 1.5.2.3.4-16, and 1.5.2.3.4-26 through 1.5.2.3.4-29 show the fault tree for this event. The fault tree is constructed for the following conditions in addition to those mentioned in Section 1.5.2.3.4.3.1:

- Large or medium LOCA has occurred.
- Low pressure coolant injection has been completed successfully; therefore, an adequate number of discharge headers are open.
- Heat exchanger cooling is necessary (use of pipe 190 is included in the quantification).
- Any two of three SI pumps can provide sufficient cooling if the low head discharge headers are unavailable.
- MOV 744 would not be closed by recirculation switch 3, because the short time period would not yet have permitted reenergizing of the valve operator.

In the event tree of a large or medium LOCA, this event is coded as H.

Table 1.5.2.3.4-17 gives the minimal cutset with one and two basic events with the house events treated as basic events. Since the use of pipe 190 has not been incorporated in the fault tree, the only single element cutset is the component cooling system. However, it has been included in the quantification process.

This fault tree is quantified under several conditions depending on the state of fan coolers, component cooling water system, and electric power. Table 1.5.2.3.4-2 gives all possible combinations from these conditions. It also refers to the quantification section, cause table, and mean and variance of the frequency of the top event.

1.5.2.3.4.5.2 Quantification.

1.5.2.3.4.5.2.1 Fan coolers unavailable; component cooling and all electric buses available. The minimal cutset and the cause tables are given in Tables 1.5.2.3.4-17 and 1.5.2.3.4-18, respectively.

1.5.2.3.4.5.2.1.1 Human error contributions. During a large LOCA, the level in the RWST would drop to the low level alarm point in approximately 20 minutes. The time window is 20 minutes. The two operators, the watch supervisor, and the shift technical advisor, (similar to a small LOCA) would be in the control room by this time. They would still be recovering from the initial very high stress conditions created by the large LOCA. Similar to a small LOCA, the two control board operators would be doing the switchover. The watch supervisor would be checking other parts of the control board, and because of the seriousness of the accident, he would be monitoring the process of switchover

closely. The shift technical advisor would not be involved in the specific detail. He would, however, be monitoring the overall plant parameters.

The three stages defined for small LOCA also apply here. However, the timing in this case is much shorter. Operator related events are discussed in two parts: events that lead to system failure, and events that lead to partial failures. Two operator related events are identified that would lead to system failure. These are:

1. Failure to initiate switchover.

2. Switch 6, in addition to switch 7, is turned to the "On" position and no corrective actions are taken within the available time.

Three things help the operators recognize that switchover should be initiated: (1) operators have received training regarding switchover, (2) the procedures would lead the operators to switchover, and (3) the RWST low level alarm would alert the operators. A large LOCA is considered a high stress situation for the operators. The handbook equates this to emergencies in the military and uses the test results from simulated military emergencies. It gives 0.25 as the point estimate for human error frequency. This is interpreted as the frequency of error in one well defined task for one operator. The suggested 5th and 95th percentiles are 0.03 and 0.75, respectively.

The handbook suggests that human error frequency within a half-hour after a large LOCA decreases from unity to 0.1 (a point estimate) given that all automatic recovery systems function normally. It would decrease to 0.25 (the human error frequency discussed earlier) if some systems do not function properly. Switchover to the recirculation phase has always been initiated by the trainees on the simulator. Operators also have extensive training and retraining on the simulator in mitigating a large LOCA. Therefore, for switchover initiation only, the basic human error is divided by two: 0.1/2 = 0.05. The dependencies among the operators are similar to those during a small LOCA. Using the dependency formulas, a point value for the frequency of failure to initiate switchover becomes

$$0.05 \times \frac{1 + 0.05}{2} \times \left(\frac{1 + 6 \times 0.05}{7}\right)^2 = 9.1 \times 10^{-4}$$

This is taken as the median and assigned an error factor of 20. For lognormal distribution the mean and variance become:

Mean: 4.75×10^{-3}

Variance: 6.00×10^{-4}

The 5th and 95th percentiles are 4.55×10^{-5} and 1.82×10^{-2}, respectively. This range includes other dependency levels, e.g., if the

shift technical advisor has zero dependence with the other operators, the point value becomes:

$$0.05 \times \frac{1 + 0.05}{2} \times \frac{1 + 6 \times 0.05}{7} \times 0.05 = 2.4 \times 10^{-4}$$

In the second event, the operators turn switch 6 to the "on" position which closes MOVs 746 and 747, and later they turn switch 7 and trip the SI pumps. It is possible to restore these valves from the control board. The error may occur for various reasons, e.g., errors by the operator at the control board in interpreting the instructions read to him, or the operator who reads the instructions skips some lines. This would be discovered when the flow to the cold legs is checked. The basic frequency of human error is 0.1. Using the dependence relationships, a point value for the frequency of occurrence becomes

$$0.1 \frac{1 + 0.1}{2} = 0.055$$

This error may be discovered by all four operators within the remaining time window. In this case, it is assumed that the shift technical advisor has low dependence with the rest of the team. Thus a point estimate for the frequency of the first event becomes

$$0.055 \times 0.10 \times \frac{1 + 0.10}{2} \times \frac{1 + 6 \times 0.10}{7} \times \frac{1 + 19 \times 0.1}{20} = 1.00 \times 10^{-4}$$

This is taken as the median and an error factor of 20 is assigned. The lognormal distribution yields:

Mean: 5.26×10^{-4}

Variance: 7.36×10^{-6}

The 5th and 95th percentiles are 5.01×10^{-6} and 2.01×10^{-3}, respectively. This range includes other dependency or basic error rates. For example, if shift technical advisor is moderately dependent and the basic human error rate for recovery is 0.25, the point estimate becomes

$$0.055 \times 0.25 \times \frac{1 + 0.25}{2} \times \left(\frac{1 + 6 \times 0.25}{7}\right)^2 = 1.10 \times 10^{-3}$$

Low head recirculation may also fail due to a combination of human error and other causes. The failure of the recirculation pumps due to human error is discussed in Section 1.5.2.3.4.4.2.1.1. This has small impact on system unreliability. Human error on RHR pumps is significant. They must be aligned manually from the control room to provide the recirculation flow when the recirculation pumps are not available.

The operators can switch to the RHR pumps and establish the recirculating flow from the containment sump. They also have to reset recirculation switch 3. Since the stress level would be very high due to failures in the recirculation pumps, the error rate for one operator is

judged to be 0.5 and the dependency among the two operators, the watch supervisor, and the shift technical advisor is very high (high dependence). A point value for the operators to fail to switch to the RHR pumps is

$$0.5 \times \left(\frac{1 + 0.5}{2}\right)^3 = 0.21$$

An error factor of 3 is chosen for this frequency. The mean and variance of lognormal distribution become:

Mean: 0.26

Variance: 3.9×10^{-2}

1.5.2.3.4.5.2.1.2 Single hardware failures. There are no single element minimal cutsets.

1.5.2.3.4.5.2.1.3 Multiple hardware failures. The approach taken here is very similar to that explained in Section 1.5.2.3.4.4.2.1.3, and only the main contributors are addressed here. For example, the failure of the normally open butterfly valves HCV-638 and HCV-640 (mean failure rate is 7.4×10^{-8} per hour) is not significant because the valves are used and verified operable every cold shutdown. Table 1.5.2.3.4-18 enumerates the main contributors. They are:

1. Both recirculation pumps fail and the operators fail to switch to RHR pumps. The mean of the unreliability of both recirculation pumps is found in Section 1.5.2.3.4.4.2.1.3:

   Mean: 1.47×10^{-4}

   The frequency of operator error is computed in Section 1.5.2.3.4.5.2.1.1. System failure frequency yields

   Mean: $1.47 \times 10^{-4} \times 0.26 = 3.82 \times 10^{-5}$

2. Both MOVs 1802A and 1802B fail to open and the operators fail to switch to RHR pumps. The following mean and variance of the frequency of failure of two MOVs are found in Section 1.5.2.3.4.4.2.1.3:

   Mean: 6.57×10^{-6}

   Variance: 1.46×10^{-11}

   System failure frequency yields

   Mean: $6.57 \times 10^{-6} \times 0.26 = 1.71 \times 10^{-6}$

3. MOVs 822B and 746 fail to open. The failure of these valves causes loss of cooling in heat exchanger 21 and flow blockage downstream of heat exchanger 22. SI pump availability is ineffective in this case.

This failure mode can be bypassed by opening MOV 889A. This would remove the heat from the sump water by cooling it in heat exchanger 22 and spraying it back into the containment. As stated previously, it is conservatively assumed that this mode of operation would not be used.

4. MOVs 822A and 822B fail to open. This failure mode causes total loss of cooling in the heat exchangers.

1.5.2.3.4.5.2.1.4 Maintenance contribution. Only the SI pumps are the main contributors here. The contribution of RHR related components is dominated by the operators' failure to switch over.

The following cutset is affected by maintenance:

- Any Two of the Three SI Pumps, MOVs 747 and 746. This is a conservative assumption because the injection phase has been successful and it is very likely that either MOV 747 or 746 is open. Section 1.5.2.3.4.4.2.1.3 gives the unreliability of one SI pump due to hardware failure:

  Mean: 6.76×10^{-3}

  Variance: 1.73×10^{-5}

  and due to maintenance:

  Mean: 1.15×10^{-3}

  Variance: 1.03×10^{-7}

  Unreliability of two out of three SI pumps becomes

  Mean: $3\ (6.76 \times 10^{-3} \times 1.15 \times 10^{-3}) = 2.3 \times 10^{-5}$.

  The frequency for one MOV to fail to open (see Section 1.5.1.1) yields:

  Mean: 2.3×10^{-3}

  Variance: 1.2×10^{-6}

  Mean of the frequency of two valves failing to open is

  Mean: $(2.3 \times 10^{-3})^2 + 1.2 \times 10^{-6} = 6.6 \times 10^{-6}$

  The mean frequency for system failure due to maintenance on SI pumps is

  Mean: $2.3 \times 10^{-5} \times 6.6 \times 10^{-6} = 1.5 \times 10^{-10}$

Thus, maintenance contribution is insignificant.

1.5.2.3.4.5.2.1.5 Other causes. The discussions given in Section 1.5.2.3.4.4.2.1.5 apply here also. The same β-factor can be used. The failure of all SI pumps and both MOVs 888 does not cause the top event here. However, if both recirculation pumps or both MOVs 1802 fail and the RHR pumps are not realigned, then system failure would occur. The same is true if both MOVs 822A and 822B fail to open.

The frequency of both recirculation pumps or both MOVs 1802 failing to operate (using β-factor) yields

Mean: $1.4 \times 10^{-2} \times (6.87 \times 10^{-3} + 2.30 \times 10^{-3}) = 1.29 \times 10^{-4}$

The mean of system failure frequency is

Mean: $1.29 \times 10^{-4} \times 0.26 = 3.35 \times 10^{-5}$

The frequency of two MOVs (822A and 822B in this case) failing to open is computed in Section 1.5.2.3.4.4.2.1.5 (using β-factor). The mean is

Mean: 3.23×10^{-5}

1.5.2.3.4.5.2.1.6 System unreliability. Table 1.5.2.3.4-18 shows the results that have been derived for the mean values of the contributors to low head recirculation unavailability when the fan coolers are unavailable and component cooling and all electric buses are available. Only the main contributors are used here for uncertainty analysis. The mathematical expression for the system unreliability in terms of the dominant contributors is:

$$Q_{LOW\ HEAD} = Q_{H1} + 0.111Q_{H1} + Q_{RC}^2\, Q_{H3} + Q_{MOV}^2\, Q_{H3} + 2Q_{MOV}^2 + B(Q_{RC} + Q_{MOV})\, Q_{H3} + 2BQ_{MOV}$$

where

Q_{H1}: Human error, failure to initiate switchover:

$\alpha = 4.75 \times 10^{-3}$, $\beta^2 = 6.0 \times 10^{-4}$

Q_{RC}: Recirculation pump unreliability:

$\alpha = 6.87 \times 10^{-3}$, $\beta^2 = 1.40 \times 10^{-4}$

Q_{H3}: Human error, failure to switch to RHR pumps:

$\alpha = 0.26$, $\beta^2 = 3.9 \times 10^{-2}$

Q_{MOV}: MOV fails to operate:

$\alpha = 2.30 \times 10^{-3}$, $\beta^2 = 1.20 \times 10^{-6}$

B: β-factor:

$\alpha = 1.4 \times 10^{-2}$, $\beta^2 = 6.1 \times 10^{-4}$

Using DPD arithmetic, the following characteristic values are obtained for $Q_{LOW\ HEAD}$:

Mean:	5.43×10^{-3}
Variance:	1.43×10^{-4}
5th Percentile:	8.80×10^{-5}
95th Percentile:	1.40×10^{-2}
Median:	2.20×10^{-3}

1.5.2.3.4.5.2.2 Fan coolers and electric bus 6A unavailable; component cooling and electric buses 2A, 3A, and 5A available. Loss of electric bus 6A at or before safeguards actuation causes the failure of recirculation pump 22, RHR pump 22, SI pump 23, and MOVs 888B, 822B, 747, 885B, and 1802B. Since 885B is electrically inoperable, recirculation via the RHR pumps is assumed not possible. However, it may be opened manually within the available time. Table 1.5.2.3.4-19 gives the cause table for this case. Each item in this table is discussed hereafter.

1.5.2.3.4.5.2.2.1 Human error contributions. The frequency of operator failure to establish low head recirculation is evaluated in Section 1.5.2.3.4.5.2.1.1. The discussions there also apply to this case. Loss of electric bus 6A would have some effect on operator error rates. The handbook increases the human error frequency to 0.25. Page 17-19: "if the automatic recovery systems function normally to mitigate the effects of the accident" the error rate is 0.1. "Otherwise, the error probability will not decrease below 0.25 but will remain at that value as long as the highly stressful conditions persist."

The discussions on human error in Section 1.5.2.3.4.5.2.1.1 also apply to this case. Bus failure would probably occur at safeguards actuation. One of the operators would immediately attempt to restore the bus from the control room. In case of failure to restore the bus from the control room, a plant operator would be dispatched to restore the bus locally. Only one control room operator would be occupied with bus restoration for the first few minutes following safeguards actuation. By the time of switchover initiation, the two operators, the watch supervisor, and the shift technical advisor would be in positions similar to those described in Section 1.5.2.3.4.5.2.1.1, except that the watch supervisor would be receiving telephone calls regarding the failed bus.

The levels of dependency are identical to those in Section 1.5.2.3.4.5.2.1.1. Similarly, the basic human error rate for failure to initiate switchover is halved. A point value for the frequency of failure to initiate switchover becomes

$$0.125 \times \frac{1 + 0.125}{2} \times \left(\frac{1 + 6 \times 0.125}{7}\right)^2 = 4.4 \times 10^{-3}$$

This is taken as the median and 20 is taken as the error factor. The lognormal distribution yields:

Mean: 2.31×10^{-2}

Variance: 1.42×10^{-2}

Error on switch 6 is discussed in Section 1.5.2.3.4.5.2.1.1. The same arguments also apply here, except that the basic human error frequency is 0.25 in this case. Moderate dependence is given to the shift technical advisor. A point value for the conditional frequency of error on switch 6 is

$$0.25 \times \frac{1 + 0.25}{2} = 0.156$$

A point value for the conditional frequency of failure to discover the error is

$$0.25 \times \left(\frac{1 + 0.25}{2}\right) \times \left(\frac{1 + 6 \times 0.25}{7}\right)^2 = 1.99 \times 10^{-2}$$

A point value for the unconditional frequency of error on switch 6 is

$$0.156 \times 0.0199 = 3.11 \times 10^{-3}$$

Taking this as the median and assigning an error factor of 20 for a lognormal distribution, the following is obtained:

Mean: 1.63×10^{-2}

Variance: 7.10×10^{-3}

1.5.2.3.4.5.2.2.2 Other causes. The only single event cutsets that have some impact on system unreliability are:

	Mean
• Recirculation pump 21	6.87×10^{-3}
• MOV 1802A	2.3×10^{-3}
• MOV 822A	2.3×10^{-3}

In the first two events, due to the short time window, credit is not given to manual opening of MOV 885A and aligning the RHR pumps for external recirculation cooling.

Unavailabilities of the components due to maintenance (see Section 1.5.2.3.4.4.2.1.5 for details) do not contribute significantly because they are at least two orders of magnitude less than the total contribution of human error.

1.5.2.3.4.5.2.2.3 System unavailability. DPD arithmetic is used to sum the three distributions given in Sections 1.5.2.3.4.5.2.2.1 and 1.5.2.3.4.5.2.2.2. The mathematical expression used for system unavailability is

$$Q_{LOW\ HEAD} = Q_{H2} + 0.706Q_{H2} + Q_{RC} + 2Q_{MOV}$$

where

Q_{H2} = Human error, failure to initiate switchovers:

$$\alpha = 2.31 \times 10^{-2},\ \beta^2 = 1.42 \times 10^{-2}$$

The other terms are defined in Section 1.5.2.3.4.5.2.1.6. The unavailability of low head recirculation in 24 hours after a large or medium LOCA has the following parameters:

Mean:	5.1×10^{-2}
Variance:	5.2×10^{-3}
5th Percentile:	5.2×10^{-3}
95th Percentile:	1.1×10^{-1}
Median:	2.9×10^{-2}.

1.5.2.3.4.5.2.3 Fan coolers and electric bus 5A unavailable; component cooling and electric buses 2A, 3A, and 6A available. Loss of electric bus 5A causes the failure of recirculation pump 21, RHR pump 22, SI pumps 21 and 22, and MOVs 888A, 822A, 746, 885A, and 1802A. The situation here is equivalent to that described in Section 1.5.2.3.4.5.2.2 in whcih bus 6A is unavailable. The same discussions and results also apply to this case. See Section 1.5.2.3.4.5.2.2.3 for the distribution of system unavailability.

1.5.2.3.4.5.2.4 Fan coolers and electric buses 2A and 3A unavailable; component cooling and electric buses 5A and 6A available. The loss of electric buses 2A and 3A causes the failure of SI pump 22 and RHR pump 21. The situation here is very similar to that described in Section 1.5.2.3.4.5.2.1, because these pumps (SI pump 22 and RHR pump 21) have little impact on system unavailability. However, this event would affect the operators. The results of Section 1.5.2.3.4.5.2.2.1 also apply here. The system unreliability is thus the sum of the two dependent distributions defined in that section because other causes do not contribute significantly. The results are:

Mean:	3.94×10^{-2}
Variance:	7.53×10^{-3}
5th Percentile:	2.60×10^{-4}

95th Percentile: 1.06×10^{-1}

Median: 7.50×10^{-3}

1.5.2.3.4.5.2.5 Fan coolers and electric buses 2A, 3A, and 6A (or 5A) unavailable; component cooling and electric bus 5A (or 6A) available. The components that would be inoperable are the same as those in Sections 1.5.2.3.4.5.2.2 (or 1.5.2.3.4.5.2.3) and 1.5.2.3.4.5.2.4. The stress level on the operators would be very high. The frequency distributions given in Section 1.5.2.3.4.5.2.2.1 are judged to be sufficiently conservative and also apply to this case. See Section 1.5.2.3.4.5.2.4 for the results.

1.5.2.3.4.5.2.6 Other conditions when fan coolers are unavailable. If electric buses 5A and 6A or 2A, 3A, 5A, and 6A are unavailable, then system failure is a certainty. The same is true when component cooling is unavailable.

1.5.2.3.4.5.2.7 All electric buses, fan coolers, and component cooling available. The only difference between this case and that in Section 1.5.2.3.4.5.2.1 is that heat exchanger cooling availability is not addressed here. Table 1.5.2.3.4-19 gives the cause table for this case. It is derived from Table 18 (heat exchanger related events are deleted). The impact of MOVs 822A and 822B to system unreliability is minimal. The mean frequency of two MOVs failing to operate is (see Section 1.5.2.3.4.4.2.1.3)

Mean: 6.57×10^{-6}

This is much smaller than the mean unreliability of the system. The results of Section 1.5.2.3.4.5.2.1.6 also apply to this case.

1.5.2.3.4.5.2.8 Other conditions when fan coolers are available. The system has already been analyzed in Sections 1.5.2.3.4.5.2.2 through 1.5.2.3.4.5.2.5 for different combinations of electric bus availability under the conditions of fan cooler unavailability and component cooling availability. In Section 1.5.2.3.4.5.2.3, it is concluded that MOV 822A has a very small impact on system unreliability. Thus, the results of Sections 1.5.2.3.4.5.2.2 through 1.5.2.3.4.5.2.5 also apply to this case (i.e., fan coolers available). When electric buses 5A and 6A are unavailable, the system fails.

If component cooling is unavailable, then recirculation pump cooling is completely dependent on auxiliary component cooling pump unavailability. In Section 1.5.2.3.4.4.2.12, it is found that the mean and variance of the reliability of both pumps are:

Mean: 7.25×10^{-5}

Variance: 2.70×10^{-8}

The same failure mode may occur due to common cause. Using β-factor, the following was obtained (see Section 1.5.2.3.4.4.2.13):

Mean: 9.5×10^{-5}

These are much smaller than the human error contribution. Therefore, the effect of component cooling availability can be dropped from the analysis when the fan coolers are available.

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1.5.2.3.4.6. Containment Spray Recirculation.

1.5.2.3.4.6.1 Fault Tree. The fault tree for the failure of containment spray recirculation is shown in Figures 1.5.2.3.4-18, 1.5.2.3.4-9 through 1.5.2.3.4-17, and 1.5.2.3.4-26 through 1.5.2.3.4-29. The top event is "Failure to Establish Containment Spray Recirculation." The fault tree is based on the following conditions in addition to those mentioned in Section 1.5.2.3.4.3:

- Containment spray has been completed successfully.
- Fan coolers are unavailable (otherwise containment spray recirculation would not be necessary).
- Component cooling is available.
- Backflow into the containment spray system is not considered since it has a very small frequency of occurrence.

In the large or medium LOCA, event trees in this event are coded as F.

This mode of operation is activated manually after the eight-switch sequence is completed. Operators open MOVs 889A and/or 889B and throttle MOVs 638 and/or 640.

Table 1.5.2.3.4-20 gives the minimal cutset with one and two elements and all house events are treated as basic events. In the event trees, the availability of containment spray recirculation is addressed only when core cooling recirculation is available. Under this condition, it is certain that there is flow of cool water in pipe 361 (downstream of MOVs 746 and 747). This implies that at least one of the heat exchangers is removing enough heat and an isolation valve (746 or 747) downstream of that heat exchanger is open. Two conditions in which core cooling recirculation (low head) would be successful are considered here. First, if both heat exchanger trains are available, then containment spray recirculation would fail only when both isolation valves 889A and 889B fail to open. Second, if one heat exchanger train is unavailable due to motor control center bus failure, then spray recirculation would fail if the isolation valve of the other train fails to open. Other causes of train failure do not contribute to spray failure. Mechanical failures in MOVs 746 and 747 are not considered because they would not affect spray recirculation. Similar failures in MOVs 822A or 822B are not considered either. This is because if the only available path to the nozzles is through a failed heat exchanger (fails to remove heat due to failures in 822 valves), containment cooling would still be achieved. The discharged coolant from the core into the containment would be cooler than the sump water because the available heat exchanger would remove more heat than is generated in the core. Table 1.5.2.3.4-21 gives the minimal cutsets (up to two elements) when core cooling recirculation is available and all house events are treated as basic events.

The minimal cutsets of Table 1.5.2.3.4-21 are only quantified under two conditions: both electric buses are available, and one electric bus (6A or 5A) is available. Under other conditions, system status can be determined with certainty. Table 1.5.2.3.4-3 summarizes the results for all the cases.

1.5.2.3.4.6.2 Quantification.

1.5.2.3.4.6.2.1 All electric buase available. Table 1.5.2.3.4-22 gives the cause table. Each item of this table is discussed hereafter.

1.5.2.3.4.6.2.1.1 Human error contributions. Containment spray recirculation is aligned after core cooling recirculation alignment is completed successfully and the fan cooler system is unavailable and/or the containment pressure rises. Successful realignment may reassure the operators and reduce their error rates. The handbook suggests 0.1 for the error rate of one operator 30 minutes after a large LOCA. Section 1.5.2.3.4.5.2.1.1 gives the dependencies among the operators.

Two events must occur for the operators to ignore containment spray recirculation. First, two of the operators (high dependence) do not follow the procedure beyond the core cooling switchover. Second, the two operators, the watch supervisor, and the shift technical advisor do not recognize the need for containment spray recirculation. The frequency of the first event is

$$0.1 \frac{1 + 0.1}{2} = 0.055$$

The conditional frequency of the second event, given that the first one has occurred, is judged to be 0.01. A point value for the frequency of system failure would be

$$0.055 \times 0.01 = 5.5 \times 10^{-4}$$

This point estimate is taken as the median value and an error factor of 10 is assigned for the spread. For lognormal distribution, the mean and variance become:

Mean: 1.5×10^{-3}

Variance: 1.3×10^{-5}

1.5.2.3.4.6.2.1.2 Single hardware failures. There are no single element cutsets.

1.5.2.3.4.6.2.1.3 Multiple hardware failures. The simultaneous failure of MOVs 889A and 889B is the dominant contributor when hardware failures are considered. The mean and variance of one valve failing to open are (data from Section 1.5.1.1):

Mean: 2.3×10^{-3}

Variance: 1.2×10^{-6}

The mean frequency for both valves failing to open becomes

Mean: $(2.3 \times 10^{-3})^2 + 1.2 \times 10^{-6} = 6.57 \times 10^{-6}$

The remaining contributors are at least an order of magnitude less than 10^{-6}.

1.5.2.3.4.6.2.1.4 Maintenance contribution. Maintenance does not have any effect on this event because, in general, MOVs 889A and 889B do not undergo maintenance during normal operation. Maintenance on other components would affect core cooling recirculation, which is available when the availability of containment spray recirculation is questioned.

1.5.2.3.4.6.2.1.5 Other causes. The discussions given in Section 1.5.2.3.4.4.2.1.5 also apply to this case. The β-factor method can be used for the pair of MOVs mentioned in Section 1.5.2.3.4.6.2.1.3. For one pair of MOVs, from Section 1.5.2.3.4.4.2.1.5, the mean is

Mean: 3.2×10^{-5}

1.5.2.3.4.6.2.1.6 System unavailability. Table 1.5.2.3.4-22 shows the results that have been derived for the mean values of the contributors to containment spray recirculation unavailability when the fan coolers are unavailable and component cooling and all electric buses are available. Only the main contributors are used here for uncertainty analysis. The mathematical expression for the unavailability of the system in terms of the unavailabilities of the dominant contributors is

$$Q_{CS} = Q_{H1} + Q_{MOV}^2 + B\ Q_{MOV}$$

where

Q_{H1}: Human error, failure to intitiate containment spray recirculation:

$\alpha = 1.50 \times 10^{-3}$, $\beta^2 = 1.30 \times 10^{-5}$

Q_{MOV}: MOV fails to operate:

$\alpha = 2.30 \times 10^{-3}$, $\beta^2 = 1.20 \times 10^{-6}$

B: β-factor:

$\alpha = 1.40 \times 10^{-2}$, $\beta^2 = 6.10 \times 10^{-4}$

Using DPD arithmetic the characteristic values for Q_{CS} are obtained:

Mean:	1.50×10^{-3}
Variance:	1.31×10^{-5}
5th Percentile:	5.50×10^{-5}

95th Percentile: 5.50×10^{-3}

Median: 5.50×10^{-4}

1.5.2.3.4.6.2.2 Electric bus 5A (or 6A) unavailable. Loss of electric bus 5A (or 6A) causes inoperability in MOVs 889A and 822A (or MOVs 889B and 822B for 6A). System availability is dependent on one train only. Table 1.5.2.3.4-23 gives the cause table for this case.

1.5.2.3.4.6.2.2.1 Human error contributions. In Section 1.5.2.3.4.5.2.2.1 operator error rates are increased because some of the operators' attention would be focused on restoring the lost bus. It is believed that this increase does not apply to error rates on containment spray recirculation because core cooling recirculation is established successfully and has some reassuring effect on the operators. Thus, the results of Section 6.2.1.1 can also be used for this case.

1.5.2.3.4.6.2.2.2 Single hardware failures. The dominant single element cutset is the failure of MOV 889B (for 6A it would be MOV 889A). The frequency of MOV failure to operate is given in Section 1.5.1.1.

1.5.2.3.4.6.2.2.3 Multiple hardware failures. All multiple hardware contributors to the unavailability of top event are on the order of 10^{-5} or lower.

1.5.2.3.4.6.2.2.4 Maintenance contribution. Maintenance does not have any effect (see Section 1.5.2.3.4.6.2.1.4).

1.5.2.3.4.6.2.2.5 Other causes. The discussions in Section 1.5.2.3.4.6.2.1.5 do not apply here because only one of the redundant trains is available.

1.5.2.3.4.6.2.2.6 System unavailability. Table 1.5.2.3.4-23 shows the results that have been derived for the mean values of the contributors to containment spray recirculation unavailability when the fan coolers and electric bus 5A are unavailable and componment cooling and electric buses 2A, 3A, and 6A are available. Only the main contributors are used here for uncertainty analysis. The results of DPD arithmetic for the unavailabilty of containment spray recirculation are:

Mean: 3.80×10^{-3}

Variance: 7.55×10^{-6}

5th Percentile: 1.10×10^{-3}

95th Percentile: 7.00×10^{-3}

Median: 3.00×10^{-3}

1.5.2.3.4.6.2.3 Other conditions. See Table 1.5.2.3.4-3 for the effect of other conditions.

1.5.2.3.4.7. Hot Leg Recirculation.

The fault tree for this event is given in Figures 1.5.2.3.4-18 through 1.5.2.3.4-30 and 1.5.2.3.4-11 through 1.5.2.3.4-16. The top event is "Failure to Establish Hot Leg Recirculation." The fault tree is constructed based on the following conditions in addition to those of Section 1.5.2.3.4.2.1:

- Large or medium LOCA has occurred.
- RCS pressure is below 170 psig.
- One SI pump can provide sufficient coolant flow.
- SI pumps have to restart.
- Containment spray is not necessary.
- At least one sump is not blocked.

Hot leg recirculation is questioned only when core cooling recirculation has been successful. Therefore, recirculation flow up to the suction side of the SI pumps is available, and the minimal cutset should include the SI pumps, and MOVs 856B, 856F, 888A, and 888B. The time to initiate hot leg recirculation is very flexible (i.e., it is not needed until approximately 24 hours following a medium or large LOCA). Therefore, it is believed that components outside the containment can be restored (if they fail) without great delay in switchover to hot leg recirculation. Thus, the only failure of concern is failure of MOVs 856B and 856F to open. The frequency of two valves failing to operate is obtained in Section 1.5.2.3.4.4.2.1.3. The mean and variance are:

Mean: 6.57×10^{-6}

Variance: 5.57×10^{-11}

The valves may fail due to causes common to both, such as errors in procedures, manufacture, installation, or design.

In Section 1.5.2.3.4.4.2.1.5, the frequency of two MOVs failing is computed using β-factor. The mean is

Mean: 3.23×10^{-5}

Unavailability of hot leg recirculation is the sum of these two distributions. Using DPD arithmetic, the following characteristic values obtained are:

Mean: 3.90×10^{-5}

Variance: 2.60×10^{-9}

5th Percentile: 2.80×10^{-6}

95th Percentile: 9.70×10^{-5}

Median: 2.08×10^{-5}

If one of electric buses 5A or 6A is unavailable, then system success is based on one MOV only. Table 1.5.2.3.4-4 shows system unavailability for these cases.

TABLE 1.5.2.3.4-1

INDIAN POINT 2 - SUMMARY OF THE RESULTS FOR HIGH HEAD RECIRCULATION (SMALL LOCA)

Conditions Transferred from the Event Tree			Data on System Unreliability in 24 Hours					Main Contributors	Section Number for Quantification	Table Number for Cause Table
Fan Coolers Available	CCS Available	Electric Buses Available	Mean	Variance	5th	Median	95th			
(RSS results)			Not Given	Not Given	4.3×10^{-3}	9.0×10^{-3}	2.2×10^{-2}	Human error at switchover: Median = 6.0×10^{-3}	-	-
No	Yes	All	6.80×10^{-4}	1.04×10^{-6}	5.0×10^{-5}	4.2×10^{-4}	1.8×10^{-3}	Human error at switchover: Mean = 3.9×10^{-4}	1.5.2.3.4.4.2.1	10
No	Yes	2A, 3A, 5A	System Failure						1.5.2.3.4.4.2.3	
No	Yes	2A, 3A, 6A	4.30×10^{-3}	4.00×10^{-6}	1.6×10^{-3}	3.6×10^{-3}	7.9×10^{-3}	Hardware failures Mean = 3.8×10^{-3}	1.5.2.3.4.4.2.2	11
No	Yes	5A, 6A	7.55×10^{-4}	1.10×10^{-6}	8.3×10^{-5}	4.8×10^{-4}	1.9×10^{-3}	Hardware failures in all SI pumps: Mean = 3.9×10^{-4}	1.5.2.3.4.4.2.4	12
No	Yes	5A	System Failure						1.5.2.3.4.4.2.6	-
No	Yes	6A	2.21×10^{-2}	1.14×10^{-4}	9.7×10^{-3}	1.9×10^{-2}	3.8×10^{-2}	Hardware failures Mean = 2.06×10^{-2}	1.5.2.3.4.4.2.5	-
No	Yes	2A, 3A	System Failure						1.5.2.3.4.4.2.6	-
No	Yes	None	System Failure						1.5.2.3.4.4.2.6	-
No	No	-	System Failure						1.5.2.3.4.4.2.6	-
Yes	-	All	4.93×10^{-4}	8.76×10^{-7}	2.0×10^{-5}	1.8×10^{-4}	9.0×10^{-4}	Human error; Mean = 3.93×10^{-4}	1.5.2.3.4.4.2.7	13
Yes	-	2A, 3A, 5A	4.02×10^{-3}	3.50×10^{-6}	1.5×10^{-3}	3.4×10^{-3}	7.4×10^{-3}	Hardware failures Mean = 3.63×10^{-3}	1.5.2.3.4.4.2.8	14
Yes	-	2A, 3A, 6A	4.02×10^{-3}	3.50×10^{-6}	1.5×10^{-3}	3.4×10^{-3}	7.4×10^{-3}	Hardware failures Mean = 3.63×10^{-3}	1.5.2.3.4.4.2.9	15
Yes	-	5A, 6A	6.03×10^{-4}	9.02×10^{-7}	5.1×10^{-5}	2.7×10^{-4}	1.3×10^{-3}	Human error; Mean = 3.93×10^{-4}	1.5.2.3.4.4.2.10	16

TABLE 1.5.2.3.4-2

INDIAN POINT 2 - SUMMARY OF THE RESULTS FOR LOW HEAD RECIRCULATION (LARGE OR MEDIUM LOCA)

Conditions Transferred from the Event Tree			Data on System Unreliability in 24 Hours					Main Contributors	Section Number for Quantification	Table Number for Cause Table
Fan Coolers Available	CCS Available	Electric Buses Available	Mean	Variance	5th	Median	95th			
(RSS results)			Not Given	Not Given	4.4×10^{-3}	1.3×10^{-2}	3.1×10^{-2}	Median = 6×10^{-3}	-	-
No	Yes	All	5.43×10^{-3}	1.43×10^{-4}	8.8×10^{-5}	2.2×10^{-3}	1.4×10^{-2}	Mean = 5.3×10^{-3}*	1.5.2.3.4.5.2.1	18
No	Yes	2A, 3A, 5A	5.10×10^{-2}	5.20×10^{-3}	5.2×10^{-3}	2.9×10^{-2}	0.11	Mean = 3.9×10^{-2}*	1.5.2.3.4.5.2.2	-
No	Yes	2A, 3A, 6A	5.10×10^{-2}	5.20×10^{-3}	5.2×10^{-3}	2.9×10^{-2}	0.11	Mean = 3.9×10^{-2}*	1.5.2.3.4.5.2.3	-
No	Yes	5A, 6A	3.90×10^{-2}	7.53×10^{-3}	2.6×10^{-3}	7.5×10^{-3}	0.10	Mean = 3.9×10^{-2}*	1.5.2.3.4.5.2.4	-
No	Yes	5A	3.90×10^{-2}	7.53×10^{-3}	2.6×10^{-3}	7.5×10^{-3}	0.10	Mean = 3.9×10^{-2}	1.5.2.3.4.5.2.5	-
No	Yes	6A	3.90×10^{-2}	7.53×10^{-3}	2.6×10^{-3}	7.5×10^{-3}	0.10	Mean = 3.9×10^{-2}	1.5.2.3.4.5.2.6	-
No	Yes	2A, 3A			System Failure				1.5.2.3.4.5.2.7	-
No	Yes	None			System Failure				1.5.2.3.4.5.2.7	-
No	No	-			System Failure				1.5.2.3.4.5.2.7	-
Yes	Yes or No	All	5.43×10^{-3}	1.43×10^{-4}	8.8×10^{-5}	2.2×10^{-3}	1.4×10^{-2}	Mean = 5.3×10^{-3}*	1.5.2.3.4.5.2.8	19
Yes	Yes or No	2A,3A,5A	5.10×10^{-2}	5.20×10^{-3}	5.2×10^{-3}	2.9×10^{-3}	0.11	Mean = 3.9×10^{-2}*	1.5.2.3.4.5.2.9	-
Yes	Yes or No	2A,3A,6A	5.10×10^{-2}	5.20×10^{-3}	5.2×10^{-3}	2.9×10^{-3}	0.11	Mean = 3.9×10^{-2}*	1.5.2.3.4.5.2.9	-
Yes	Yes or No	5A, 6A	3.90×10^{-2}	7.53×10^{-3}	2.6×10^{-3}	7.5×10^{-3}	0.10	Mean = 3.9×10^{-2}*	1.5.2.3.4.5.2.9	-

*Human error at switchover.

TABLE 1.5.2.3.4-3

INDIAN POINT 2 - SUMMARY OF THE RESULTS FOR CONTAINMENT SPRAY RECIRCULATION (LARGE OR MEDIUM LOCA; CORE COOLING RECIRCULATION SUCCESSFUL)

Conditions Transferred from the Event Tree			Data on System Unreliability in 24 Hours					Main Contributors	Section Number for Quantification	Table Number for Cause Table
Fan Coolers Available	CCS Available	Electric Buses Available	Mean	Variance	5th	Median	95th			
(RSS results)			Not Given	Not Given	2.5×10^{-5}	1.0×10^{-4}	9.0×10^{-4}	Maintenance and common mode		
No	Yes	All	1.5×10^{-3}	1.30×10^{-6}	5.5×10^{-5}	5.5×10^{-4}	5.5×10^{-3}	Human error at switchover; Mean = 1.5×10^{-3}	1.5.2.3.4.6.2.1	22
No	Yes	2A,3A,5A	3.8×10^{-3}	7.55×10^{-6}	1.1×10^{-3}	3.0×10^{-3}	7.0×10^{-3}	MOV failure to open Mean = 2.3×10^{-3}	1.5.2.3.4.6.2.2	23
No	Yes	2A,3A,6A	3.8×10^{-3}	7.55×10^{-6}	1.1×10^{-3}	3.0×10^{-3}	7.0×10^{-3}	MOV failure to open Mean = 2.3×10^{-3}	1.5.2.3.4.6.2.2	23
No	Yes	5A, 6A	1.5×10^{-3}	1.30×10^{-6}	5.5×10^{-5}	5.5×10^{-4}	5.5×10^{-3}	Human error at switchover; Mean = 1.5×10^{-3}	1.5.2.3.4.6.2.1*	22*
No	Yes	5A	3.8×10^{-3}	7.55×10^{-6}	1.1×10^{-3}	3.0×10^{-3}	7.0×10^{-3}	MOV failure to open Mean = 2.3×10^{-3}	1.5.2.3.4.6.2.2	23
No	Yes	6A	3.8×10^{-3}	7.55×10^{-6}	1.1×10^{-3}	3.0×10^{-3}	7.0×10^{-3}	MOV failure to open Mean = 2.3×10^{-3}	1.5.2.3.4.6.2.2*	23*
No	Yes	2A, 3A	System Failure							-
No	Yes	None	System Failure							-
No	No	-	System Failure							-
Yes	-	-	System Unavailability Not Questioned							-

*Similar case in this table or section.

TABLE 1.5.2.3.4-4

INDIAN POINT 2 - SUMMARY OF THE RESULTS FOR HOT LEG RECIRCULATION (LARGE OR MEDIUM LOCA)

Conditions Transferred from the Event Tree	Data on System Unreliability in 24 Hours					Main Contributors
Electric Buses Available	Mean	Variance	5th	Median	95th	
(RSS results)	Not Given	Not Given	4.4×10^{-3}	1.3×10^{-2}	3.1×10^{-2}	Human error or switchover Median = 6×10^{-3}
All	3.9×10^{-5}	2.6×10^{-9}	2.8×10^{-6}	2.0×10^{-5}	9.7×10^{-5}	Common cause failures in both MOVs 856B and F Mean = 3.2×10^{-5}
2A,3A,5A	2.3×10^{-3}	1.2×10^{-6}	9.77×10^{-4}	2.1×10^{-3}	4.4×10^{-3}	MOV 856F fails to open Mean = 2.3×10^{-3}
2A,3A,6A	2.3×10^{-3}	1.2×10^{-6}	9.77×10^{-4}	2.1×10^{-3}	4.4×10^{-3}	MOV 856B fails to open Mean = 2.3×10^{-3}
5A, 6A	3.9×10^{-5}	2.6×10^{-9}	2.8×10^{-6}	2.0×10^{-5}	9.7×10^{-5}	Common cause failures in both MOVs 856B and F Mean = 2.8×10^{-3}
5A	2.3×10^{-3}	1.2×10^{-6}	9.77×10^{-4}	2.1×10^{-3}	4.4×10^{-3}	MOV 856F fails to open Mean = 2.3×10^{-3}
6A	2.3×10^{-3}	1.2×10^{-6}	9.77×10^{-4}	2.1×10^{-3}	4.4×10^{-3}	MOV 856B fails to open Mean = 2.3×10^{-3}
2A, 3A	System Failure					
None	System Failure					

TABLE 1.5.2.3.4-5

INDIAN POINT 2 - POWER SUPPLIES FOR THE RECIRCULATION SYSTEM COMPONENTS

Motor-Operated Valve Power Supplies

Valve Designator	MCC Bus	Valve Designator	MCC Bus
638	26B	885A	26A
640	26A	885B	26B
744	26A	887A	26A
745A	26B	887B	26B
745B	26A	888A	26A
746	26A	888B	26B
747	26B	889A	26A
822A	26A	889B	26B
822B	26B	1802A	26A
856B	26B	1802B	26B
856F	26A	1805	26B
882	26B	1810	26A
883	26B		

Pump Power Supplies

Pump	AC Bus (power)	DC Bus/Backup DC Bus (control)
RHR 21	3A	21/23
RHR 22	6A	22/24
SI 21	5A	21/23
SI 22	2A	22/24
SI 23	6A	22/24
Recirculation 21	5A	21/23
Recirculation 22	6A	22/24
Auxiliary Component Cooling 21	26A	-
Auxiliary Component Cooling 22	26B	-

TABLE 1.5.2.3.4-6

INDIAN POINT 2 - TEST REQUIREMENTS
FOR THE RECIRCULATION SYSTEM COMPONENTS

Valves

Valve	Action	Frequency
MOVs		
744	Verify Flow Stroke Test	Monthly Refueling
745 A,B	Stroke Test Verify Flow	Quarterly Every Cold Shutdown
746, 747	Stroke Test/Verify Flow	Every Cold Shutdown
822 A,B	Stroke Test/Verify Flow	Every Cold Shutdown
856 A,E,C,D	Check Mechanical Stops Stroke Test/Verify Flow	Quarterly Refueling
856 B,F	Stroke Test and Interlock Test	Refueling
883	Verify Closed Verify Flow	Monthly Refueling
885 A,B	Verify Closed (One of Two) Stroke Test	Monthly Quarterly
888 A,B	Verify Closed Stroke Test	Monthly Quarterly
889 A,B	Verify Closed (One of Two) Stroke Test	Monthly Quarterly
1802 A,B	Stroke Test Verify Closed	Quarterly Refueling

TABLE 1.5.2.3.4-6 (continued)

INDIAN POINT 2 - TEST REQUIREMENTS
FOR THE RECIRCULATION SYSTEM COMPONENTS

Valves

Valve	Action	Frequency
1805	Stroke Test	Quarterly
638, 640	Stroke Test Verify Flow	Quarterly Every Cold Shutdown
Manual Valves		
735 A,B*	Verify Flow	Monthly
739 A,B*	Verify Flow	Monthly
751 A,B	Verify Flow	Monthly
752 A,B	Verify Flow	Monthly
753 A,B,C,...,H	Verify Flow	Monthly
818 A, B	Verify Flow	Every Cold Shutdown
820 A, B	Verify Flow	Every Cold Shutdown
846*	Verify Flow	Monthly
898*	Stroke Test	Quarterly
1863*	Verify Flow	refueling
Check Valves		
738 A, B	Verify Flow	Monthly
741	Verify Flow	Monthly
755 A, B	Verify Flow	Monthly
886 A, B	Verify Flow	Refueling
895 A, B, C, D	Leakage Test	Refueling
897 A, B, C, D	Leakage test Verify Flow	Refueling Every Cold Shutdown
838 A, B, C, D	Leakage Test Verify Flow	Refueling Every Cold Shutdown

Level Indicators

The level indicators for containment and recirculation sumps are tested for operability at every refueling.

*All locked valves are verified to be locked in their required positions monthly.

TABLE 1.5.2.3.4-6 (continued)

INDIAN POINT 2 - TEST REQUIREMENTS
FOR THE RECIRCULATION SYSTEM COMPONENTS

Pumps

Pump	Action	Frequency
RHR 21, 22	Run for 20 Minutes Full Flow	Monthly Refueling
SI 21, 22, 23	Run for 20 Minutes Full Flow	Monthly Refueling
Recirculation 21, 22	Run for 20 Minutes	Refueling
Auxiliary Component Cooling 21, 22	Run for 20 Minutes	Monthly

TABLE 1.5.2.3.4-7

INDIAN POINT 2 - FAILURE MODE OF COMPONENTS AND THEIR CODE USED IN THE FAULT TREES

Component	Failure Mode	Code Used In Fault Tree	Mean	Data Source Table 1.5.1.4 (item)
Check Valves				
886(A,B) 755(A,B) 741 738(A,B) 897(A,B,C,D) 838(A,B,C,D) 857(A,B,F,M)	Stuck closed	ECV886(A,B)C UCV755(A,B)C ECV-741C ECV738(A,B)C ECV897(A,B,C,D)C ECV838(A,B,C,D)C HCV857(A,B,F,M)C	7.02×10^{-5}	3
895(A,B,C,D)	Leakage	ECV895(A,B,C,D)L	2.06×10^{-6}	4
Manual Valve				
820(A,B) 818(A,B) 751(A,B) 752(A,B) 753(A,B,...,H) 739(A,B) 735(A,B)	Transfers closed/ Inadvertently closed	UXV820(A,B)C UXV818(A,B)C UXV751(A,B)C UXV752(A,B)C UXV753(A,B,...,H) EXV739(A,B)C EXV735(A,B)C	7.40×10^{-8}	1
846 1863	Open Excessive leakage/ Inadvertently open	EXV-846B EXV1863B	(see text)	--

TABLE 1.5.2.3.4-7 (continued)

INDIAN POINT 2 - FAILURE MODE OF COMPONENTS AND THEIR CODE USED IN THE FAULT TREES

Component	Failure Mode	Code Used In Fault Tree	Mean	Data Source Table 1.5.1.4 (item)
MOVs				
856(A,C,D,E)	Does not close due to mechanical failure	HMV856(A,C,D,E)X	2.32×10^{-3}	6
888(A,B) 889(A,B) 822(A,B) 885(A,B) 744 746 747 856(B,F) 1802(A,B)	Does not open due to mechanical failure	HMV888(A,B)Q CMV889(A,B)Q UMV822(A,B)Q EMV885(A,B)Q EMV-744Q EMV-746Q EMV-747Q HMV856(B,F)Q EMV802(A,B)Q	2.32×10^{-3}	6
883	Excessive leakage due to mechanical failure	EMV-883B	9.65×10^{-8}	7
745(A,B) 744 1805 638 640	Transfers closed due to mechanical failure	EMV745(A,B)C EMV744-C EMV1805C EMV-638C EMV-640C	7.40×10^{-8}	1
Pumps				
RHR(21,22)	Fails when running, includes motor and all other related components that are at pump location	EPMRH(21,22)S	1.63×10^{-5}/hr	14
RECIRC(21,22)		EPMRC(21,22)S	1.95×10^{-5}/hr	18
SI(21,22,23)		EPMSI(21,22,23)S	1.59×10^{-5}/hr	13
Auxiliary Component Cooling (21,22)		EPMCC(21,22)S	1.68×10^{-5}/hr	16

TABLE 1.5.2.3.4-7 (continued)

INDIAN POINT 2 - FAILURE MODE OF COMPONENTS AND THEIR CODE USED IN THE FAULT TREES

Component	Failure Mode	Code Used In Fault Tree	Mean	Data Source Table 1.5.1.4 (item)
Pumps				
RHR(21,22) RECIRC(21,22) SI(21,22,23) Auxiliary Component Cooling (21,22)	Fails to start, includes all components that are at pump location	EMORH(21,22)S EMORC(21,22)S EMOSI(21,22,23)S EMOCC(21,22)S	6.41×10^{-3}	11
Pipes				
No. 60 No. 361	Plugged or breached	HPPLN60E HPPL361E	8.60×10^{-10}	RSS
Noncomponent Events				
Containment Sump	Blockage of gratings	ECNTSUMP	5.00×10^{-5}	1.5.2.3.4.3.3
Recirculation Sump	Blockage of gratings	ERECSUMP		
Component Cooling System	System failure	UCCWFAIL	House Event	--
SI System	System failure	HDISCHDN	1.10×10^{-4}	
Low Head Injection System	System failure	ELOHDDIS	6.80×10^{-6}	
Interlock Circuitry				
856(B,F)	Interlock fails to give permissive signal to open 856-valves	H856(B,F)ILC	(see text)	

TABLE 1.5.2.3.4-7 (continued)

INDIAN POINT 2 - FAILURE MODE OF COMPONENTS AND THEIR CODE USED IN THE FAULT TREES

Component	Failure Mode	Code Used In Fault Tree	Mean	Data Source Table 1.5.1.4 (item)
Control Circuitry for Pumps				
RHR(21,22) RECIRC(21,22) SI(21,22,23) Auxiliary Component Cooling (21,22)	Fails to provide start signal or gives inadvertent stop signal	ECNTRH(21,22)S ECNTRC(21,22)S ECNTSI(21,22,23)S ECNTCC(21,22)S	Has been included as part of pump	
Control Circuitry for Valves				
856(A,C,D,E)	Fails to provide close signal	HCNT856(A,C,D,E)	Has been included as part of MOV	
883	Inadvertently opens the valve	ECNT-883		
888(A,B) 889(A,B) 822(A,B) 885(A,B) 744 746 747 856(B,F) 1802(A,B)	Fails to provide open signal	HCNT888(A,B) CCNT889(A,B) UCNT822(A,B) ECNT885(A,B) ECNT-744 ECNT-746 ECNT-747 HCNT856(B,F) ECNT802(A,B)		

TABLE 1.5.2.3.4-7 (continued)

INDIAN POINT 2 - FAILURE MODE OF COMPONENTS AND THEIR CODE USED IN THE FAULT TREES

Component	Failure Mode	Code Used In Fault Tree	Mean	Data Source Table 1.5.1.4 (item)
745(A,B) 744 1805 638 640	Inadvertently closes the valve	ECNT745(A,B) ECNT744 ECNT1805 ECNT-638 ECNT-640		
Electric Power				
Bus 2A Bus 3A Bus 5A Bus 6A DC Power to Breakers of Bus 3A,5A DC Power to Breakers of Bus 2A,6A MCC 26A MCC 26B	Insufficient power	JBS 22AD JBS 23AD JBS 25AD JBS 26AD 4BS2A5AD 4BS3A6AD JBS226AD JBS226BD	House Event	

TABLE 1.5.2.3.4-8

INDIAN POINT 2 - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential For Other System Impact	Initiating Event	Comments
293 (downstream of 1802 valves)	10	Partial, RHR pumps can be used.	No	No	Would be detected indirectly within 1 day.
293 (upstream of 1802 valves).	10	Partial, RHR pumps can be used.	No	No	Would be detected indirectly during the quarterly stroke test on 1802 valves.
55 and 54 (single pipes providing component cooling water to recircu-lation pumps)	3	Partial, RHR pumps can be used.	Maybe, CCW	No	Would be detected during component cooling system operation.
52 and 53 (single lines in CCW system that connects to RHR heat exchanger secondary side)	18, 16, 12	No, unless fan coolers are unavailable.	Yes, CCW	No	Would be detected during component cooling system operation.
9 (crosstie between the RHR heat exchangers, the connecting pipes from low pressure pumps).		Partial; it can be isolated by 745 valves, then only one heat exchanger will be ineffective.	Maybe, LPIS	No	Would be detected indirectly within 1 day, it can also be isolated.

TABLE 1.5.2.3.4-8 (continued)

INDIAN POINT 2 - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential For Other System Impact	Initiating Event	Comments
60 (connecting line between SI pumps and RHR heat exchangers)	8	Partial failure in high head recirculation, and may fail one spray recirculation train and one low-head recirculation train.	Maybe, HPIS	No	Would be detected through loss of inventory in the RWST.
361 (connecting line between RHR heat exchangers and low head injection headers)	10	Partial failure in low pressure recirculation, the SI pumps can be used.	Yes, LPIS	No	It would be detected whenever RHR system is used. (i.e., next cold shutdown.)
57 (suction to RHR from containment sump upstream of 885 valves)	18	Partial, recirculation pumps can be used.	No	No	Would be detected during refueling.
351, 352, 353, 350 (cold leg injection headers low head)	6, 10	Partial, depending on the location it could be equivalent to line 361 failure.	No	Potential for large LOCA, if occurs downstream of check valves	

TABLE 1.5.2.3.4-8 (continued)

INDIAN POINT 2 - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential For Other System Impact	Initiating Event	Comments
56, 16 (cold leg injection headers, high head)	2	Partial, can be isolated.	No	Potential for small LOCA, if occurs down-stream of check valves	
56, 16 (hot leg injection headers)	2	Partial, can be isolated.	No	Potential for small LOCA, if occurs down-stream of check valves	
56, 16 (high head injection headers, between SI pumps and 856 valves)	6	Partial, the other train can be used.	No	No	

TABLE 1.5.2.3.4-9

INDIAN POINT 2 - MINIMAL CUTSETS FOR THE FAULT TREE FOR HIGH HEAD RECIRCULATION WHEN ALL CONDITIONS ARE IMPOSED ON ANY OF THE EVENTS AND ALL HOUSE EVENTS ARE TREATED LIKE BASIC EVENTS

CUTSETS WITH 1 BASIC EVENT

3)	1)	HPPLN60E		2)	JBS226BD		3)	UCCWFAIL				

CUTSETS WITH 2 BASIC EVENTS

7)	1)	HCNT888B	HCNT888A	2)	HMV888BQ	HCNT888A	3)	HCNT888B	HMV888AQ	4)	HMV888BQ	HMV888AQ
11)	5)	ECNT-63B	UCNT822B	6)	EMV-638C	UCNT822B	7)	ECNT-638	UMV822BQ	8)	EMV-638C	UMV822BQ
15)	9)	ERECSUMP	ECNT885A	10)	ERECSUMP	EMV885AQ	11)	ERECSUMP	ECNT885B	12)	ERECSUMP	EMV885BQ
19)	13)	ERECSUMP	ECNT1805	14)	ERECSUMP	EMV1805C	15)	ERECSUMP	ECV-741C	16)	ERECSUMP	ECNTSUMP
23)	17)	ECNT744-	ERECSUMP	18)	EMV744-Q	ERECSUMP	19)	ECNT-638	UXV820BC	20)	EMV-638C	UXV8208C
27)	21)	ECNT-638	UXV818BC	22)	EMV-638C	UXV818BC	23)	UXV820BC	UCNT822A	24)	UXV818BC	UCNT822A
31)	25)	UXV820BC	UMV822AQ	26)	UXV818BC	UMV822AQ	27)	UXV820BC	UXV820AC	28)	UXV818BC	UXV820AC
35)	29)	UXV820BC	UXV818AC	30)	UXV818BC	UXV818BC	31)	UXV820BC	ECNT-640	32)	UXV818BC	ECNT-64Q
39)	33)	UXV820BC	EMV-640C	34)	UXV818BC	EMV-640C	35)	UXV820BC	ECNT-746	36)	UXV818BC	ECNT-746
43)	37)	UXV820BC	EMV-746Q	38)	UXV818BC	EMV-746Q	39)	UXV820BC	ECNT-747	40)	UXV818BC	ECNT-747
47)	41)	UXV820BC	EMV-747Q	42)	UXV818BC	EMV-747Q	43)	UCNT822B	UCNT822A	44)	UMV822BQ	UCNT822A
51)	45)	UCNT822B	UMV822AQ	46)	UMV822BQ	UMV822AQ	47)	UCNT822B	UXV820AC	48)	UMV822BQ	UXV820AC
55)	49)	UCNT822B	UXV818AC	50)	UMV822BQ	UXV818AC	51)	UCNT822B	ECNT-640	52)	UMV822BQ	ECNT-640
59)	53)	UCNT822B	EMV-640C	54)	UMV822BQ	EMV-640C	55)	UCNT822B	ECNT-746	56)	UMV822BQ	ECNT-746
63)	57)	UCNT822B	EMV-746Q	58)	UMV822BQ	EMV-746Q	59)	UCNT822B	ENCT-747	60)	UMV822BQ	ECNT-747
67)	61)	UCNT822B	EMV-747Q	62)	UMV822BQ	EMV-747Q	63)	HCNT888B	JBS226AD	64)	HMV888BQ	JBS226AD
71)	65)	ECNT802B	JBS226AD	66)	EMV802BQ	JBS226AD	67)	JBS226AD	ERECSUMP	68)	ECNT745A	JBS226AD
75)	69)	EMV745AC	JBS226AD	70)	ECNT745B	JBS226AD	71)	EMV745BC	JBS226AD	72)	UXV820BC	JBS226AD
79)	73)	UXV818BC	JBS226AD	74)	UCNT822B	JBS226AD	75)	UMV822BQ	JBS226AD	76)	UXV751AC	4BS222-D
83)	77)	ECV886AC	4BS222-D	78)	UXV752AC	4BS222-D	79)	EPMRC21S	4BS222-D	80)	EMORC21S	4BS222-D
87)	81)	ECNTRC21	4BS222-D	82)	ERECSUMP	4BS222-D	83)	HPMSI23S	4BS221-D	84)	HMOS123S	4BS221-D
91)	85)	HCNTSI23	4BS221-D	86)	4BS221-D	4BS222-D	87)	JBS26A-D	4BS221-D	88)	JBS25A-D	4BS222-D

TABLE 1.5.2.3.4-10

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS UNAVAILABLE, COMPONENT COOLING AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	3.46×10^{-4}	NR*	Fails	No effect	No effect
Switch 7 is turned to on position and no recovery actions are taken.	4.72×10^{-5}	SI pumps stop	Fails	No effect	No effect
Hardware					
Single element cutsets:					
Loss of power in electric bus 26B and containment spray recirculation is not used to cool the sump water.	1.90×10^{-6}	MOVs 822B and 747	Fails	No effect	No effect
Pipe 60 rupture (8 inch).	1.40×10^{-7}		Fails	No effect	No effect
Multiple failures:					
Mechanical failure in both recirculation pumps and operator error in switching to RHR pumps.	2.82×10^{-6}	Recirculation pumps 21 and 22 and all RHR subsystems	Fails	Containment spray recirculation	No effect

*NR = not relevant.

TABLE 1.5.2.3.4-10 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS UNAVAILABLE, COMPONENT COOLING AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
MOV 822B does not open, operator error in using MOVs 746 and 747, and containment spray recirculation is not used to cool the sump water.	3.51×10^{-5}	MOV 822B and MOV 747	Fails	No effect	No effect
All three SI pumps fail.	8.09×10^{-7}	SI pumps 21, 22 and 23	Fails	No effect	No effect
MOVs 822A and 822B do not open.	6.57×10^{-6}	MOVs 822A and 822B	Fails	Containment spray recirculation	No effect
MOVs 888A and 888B do not open.	6.57×10^{-6}	MOVs 888A and 888B	Fails	No effect	No effect
MOVs 822B and 747 and containment spray recirculation is not used to cool the sump water.	6.57×10^{-6}	MOVs 822B and 747	Fails	No effect	No effect
MOVs 822B and 746 do not open and containment spray recirculation is not used to cool the sump water.	6.57×10^{-6}	MOVs 822B and 746	Fails	No effect	No effect

TABLE 1.5.2.3.4-10 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS UNAVAILABLE, COMPONENT COOLING AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Testing	NR*	NR*	No effect	NR*	No effect
Maintenance and Hardware					
Maintenance on one SI pump and mechanical failure of the other two.	2.20×10^{-7}	All three SI pumps unavailable	Fails	No effect	No effect
Other Causes					
See Section 1.5.2.3.4.4.2.1.5 for details.	2.25×10^{-4}	SI pumps or MOVs 888	Fails	Cause dependent	Cause dependent
Total frequency of system failure.	6.80×10^{-4}				

*NR = not relevant.

TABLE 1.5.2.3.4-11

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS AND ELECTRIC BUS 5A UNAVAILABLE, COMPONENT COOLING AND ELECTRIC BUSES 2A, 3A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	3.46×10^{-4}	NR*	Fails	No effect	No effect
Switch 7 is turned to on position and no recovery.	4.72×10^{-5}	SI pumps stop	Fails	No effect	No effect
Hardware					
Single element cutsets:					
Loss of power in electric bus 26B.	1.90×10^{-6}	MOVs 822B, 747, and 888B	Fails	Containment spray recirculation	No effect
Pipe 60 rupture (8 inch).	1.40×10^{-7}		Fails	No effect	No effect
MOV 822B fails to open.	2.30×10^{-3}	MOV 822B	Fails	Containment spray recirculation	No effect

*NR = not relevant.

TABLE 1.5.2.3.4-11 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS AND ELECTRIC BUS 5A UNAVAILABLE, COMPONENT COOLING AND ELECTRIC BUSES 2A, 3A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Multiple Failures					
SI pump 22 and 23 fail to run.	6.30×10^{-5}	SI pump 22 and 23	Fails	No effect	No effect
Recirculation pump 22 fails to run and operators fail to align the RHR pumps.	8.60×10^{-4}	Recirculation pump 22 and RHR pumps	Fails	Containment spray recirculation	No effect
MOV 1802B fails to open and operators fail to align the RHR pumps.	2.90×10^{-4}	MOV 1802B and RHR pumps	Fails	Containment spray recirculation	No effect
MOV 888B fails to open and operators fail to manually open 888A or 888B.	2.90×10^{-4}	MOV 888B and 888A	Fails	No effect	No effect
Testing	NR*	NR*	No effect	NR*	No effect
Maintenance					
See Section 1.5.2.3.4.4.2.3.4 for details	1.50×10^{-5}	SI pump 23 or MOV 888B	Fails	No effect	No effect

*NR = not relevant.

TABLE 1.5.2.3.4-11 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS AND ELECTRIC BUS 5A UNAVAILABLE, COMPONENT COOLING AND ELECTRIC BUSES 2A, 3A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Other Causes See Section 1.5.2.3.4.4.2.3.5 for details.	9.46×10^{-5}	SI pump 22 and 23	Fails	Cause dependent	Cause dependent
Total frequency of system failure.	4.30×10^{-3}				

TABLE 1.5.2.3.4-12

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS AND ELECTRIC BUSES 2A AND 3A UNAVAILABLE, COMPONENT COOLING AND ELECTRIC BUSES 5A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	3.46×10^{-4}	NR*	Fails	No effect	No effect
Switch 7 is turned to on position and no recovery action.	4.72×10^{-5}	SI pumps stop	Fails	No effect	No effect
Hardware					
Single element cutsets:					
Loss of power in electric bus 26B and containment spray recirculation is not used to cool the sump.	1.90×10^{-6}	MOVs 822B and 747	Fails	No effect	No effect
Pipe 60 rupture (8 inch).	1.40×10^{-7}	Pipe 60	Fails	No effect	No effect

*NR = not relevant.

TABLE 1.5.2.3.4-12 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS AND ELECTRIC BUSES 2A AND 3A UNAVAILABLE, COMPONENT COOLING AND ELECTRIC BUSES 5A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Multiple Failures					
Mechanical failure in both recirculation pumps and operator error in switching to RHR pumps.	2.82×10^{-6}	Recirculation pumps 21 and 22 and all RHR subsystems	Fails	Containment spray recirculation	No effect
MOV 822B does not open and operator error in using MOV 747 and 746, and containment spray recirculation is not used to cool the sump water.	3.51×10^{-5}	MOV 822B and MOV 747	Fails	No effect	No effect
SI pumps 21 and 23 fail.	6.30×10^{-5}	SI pumps 21 and 23	Fails	No effect	No effect
MOVs 888A and 888B do not open and operators fail to open either one manually.	6.57×10^{-6}	MOVs 888A and 888B	Fails	No effect	No effect
MOVs 822B and 747 do not open and containment spray recirculation is not used to cool the sump water.	6.57×10^{-6}	MOVs 822B and 747	Fails	No effect	No effect

TABLE 1.5.2.3.4-12 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS AND ELECTRIC BUSES 2A AND 3A UNAVAILABLE, COMPONENT COOLING AND ELECTRIC BUSES 5A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
MOVS 822B and 746 do not open and containment spray recirculation is not used to cool the sump water.	6.57×10^{-6}	MOVs 822B and 746	Fails	No effect	No effect
MOVs 822A and 822B dc not open.	6.57×10^{-6}	MOVs 822A and 822B	Fails	Containment spray recirculation	No effect
Testing	NR*	NR*	No effect	NR*	No effect
Maintenance and Hardware					
Maintenance on one SI pump and mechanical failure of the other.	1.50×10^{-5}	All three SI pumps unavailable	Fails	No effect	No effect
Other Causes					
See Section 1.5.2.3.4.4.2.1.5 for details	2.25×10^{-4}	SI Pumps or MOV 888	Fails	Cause dependent	Cause dependent
Total frequency of system failure.	7.55×10^{-4}				

*NR = not relevant

TABLE 1.5.2.3.4-13

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS, COMPONENT COOLING AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	3.46×10^{-4}	NR*	Fails	No effect	No effect
Switch 7 is turned to on position and no recovery action are taken.	4.72×10^{-5}	SI pumps stop	Fails	No effect	No effect
Hardware					
Single element cutsets:					
Pipe 60 rupture (8 inch) and pipe 190 is not used.	1.70×10^{-8}		Fails	No effect	No effect
Multiple Failures					
Mechanical failure in both recirculation pumps and operator error in switching to RHR pumps.	2.84×10^{-6}	Recirculation pumps 21 and 22 and all RHR subsystems.	Fails	Containment spray recirculation	No effect
All three SI pumps fail.	8.09×10^{-7}	SI pumps 21, 22 and 23	Fails	No effect	No effect

*NR = not relevant

TABLE 1.5.2.3.4-13 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH FAN COOLERS, COMPONENT COOLING AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
MOVs 888A and 888B do not open and pipe 190 is not used.	7.88×10^{-7}	MOVs 888A and 888B	Fails	No effect	No effect
Testing	NR*	NR*	No effect	NR*	No effect
Maintenance and Hardware					
Maintenance on one SI pump and mechanical failure of the other two.	2.20×10^{-7}	All three SI pumps	Fails	No effect	No effect
Other Causes					
See Section 1.5.2.3.4.4.2.1.5 for details	9.85×10^{-5}	SI pumps or MOV 888	Fails	Cause dependent	Cause dependent
Total frequency of system failure.	4.93×10^{-4}				

*NR = not relevant

TABLE 1.5.2.3.4-14

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH ELECTRIC BUS 6A UNAVAILABLE, FAN COOLERS, COMPONENT COOLING AND ELECTRIC BUSES 2A, 3A AND 5A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	3.46×10^{-4}	NR*	Fails	No effect	No effect
Switch 7 is turned to on position and no recovery.	4.72×10^{-5}	SI pumps stop	Fails	No effect	No effect
Hardware					
Single element cutsets:					
Loss of power in electric bus 26A and failure to use pipe 190.	2.3×10^{-7}	MOVs 888A, 822A, 746, 1802A	Fails	Containment spray recircu-lation	No effect
Pipe 60 ruptures (8 inch) and failure to use pipe 190.	1.70×10^{-8}		Fails	No effect	No effect
Multiple Failures					
SI pumps 21 and 22	6.30×10^{-5}	SI pumps 21 and 22	Fails	No effect	No effect
Recirculation pump 21 fails to run and the RHR pumps are not aligned manually.	8.60×10^{-4}	Recirculation pump 21 and RHR pumps	Fails	Containment spray recir-culation	No effect

*NR = not relevant

TABLE 1.5.2.3.4-14 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH ELECTRIC BUS 6A UNAVAILABLE, FAN COOLERS COMPONENT COOLING AND ELECTRIC BUSES 2A, 3A AND 5A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
MOV 1802A fails to open and the RHR pumps are not aligned manually.	2.90×10^{-4}	MOV 1802A and RHR pumps	Fails	Containment spray recirculation.	No effect
MOV 888A fails to open and operators fail to manually open MOVs 888A and 888B.	2.90×10^{-4}	MOVs 888A and 888B	Fails	No effect	No effect
Testing	NR*	NR*	No effect	NR*	No effect
Maintenance					
One SI pump under maintenance, the other fails due to hardware.	7.50×10^{-6}	SI pump 23	Fails	No effect	No effect
Other Causes					
See Section 1.5.2.3.4.4.2.2.5 for details.	9.5×10^{-5}	SI pump 22 and 23	Fails	Cause dependent	Cause dependent
Total frequency of system failure.	2.00×10^{-3}				

*NR = not relevant

TABLE 1.5.2.3.4-15

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH ELECTRIC BUS 5A UNAVAILABLE, FAN COOLERS, COMPONENT COOLING AND ELECTRIC BUSES 2A, 3A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	3.46×10^{-4}	NR*	Fails	No effect	No effect
Switch 7 is turned to on position and no recovery.	4.72×10^{-5}	SI pumps stop	Fails	No effect	No effect
Hardware					
Single element cutsets:					
Loss of power in electric bus 26B and failure to use pipe 190.	2.3×10^{-7}	MOV 888B 822B, 747, 1802B	Fails	Containment spray recircu-lation	No effect
Pipe 60 ruptures (8 inch) and failure to use pipe 190.	1.70×10^{-8}		Fails	No effect	No effect
Multiple Failures					
SI pumps 23 and 22 fail to run.	6.30×10^{-5}	SI pump 23 and 22	Fails	No effect	No effect

*NR = not relevant

TABLE 1.5.2.3.4-15 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH ELECTRIC BUS 5A UNAVAILABLE, FAN COOLERS, COMPONENT COOLING AND ELECTRIC BUSES 2A, 3A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Recirculation pump 22 fails to run and operators fail to align RHR pumps manually.	8.60×10^{-4}	Recirculation pump 22 and RHR pumps	Fails	Containment spray recirculation	No effect
MOV 1802B fails to open and the RHR pumps are not aligned manually.	2.90×10^{-4}	MOV 1802B and RHR pumps	Fails	Containment spray recirculation	No effect
MOV 888B fails to open and operators fail to manually open MOVs 888A and 888B.	2.90×10^{-4}	MOV 888A and 888B	Fails	No effect	No effect
Testing	NR*	NR*	No effect	NR*	No effect
Maintenance					
One SI pump under maintenance, the other fails due to hardware.	7.50×10^{-6}	SI pump 23	Fails	No effect	No effect
Other Causes					
See Section 1.5.2.3.4.4.2.3.5 for details	9.5×10^{-5}	SI pump 22 and 23	Fails	Cause Dependent	Cause Dependent
Total frequency of system failure.	2.00×10^{-3}				

*NR = not relevant

TABLE 1.5.2.3.4-16

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH ELECTRIC BUSES 2A AND 3A UNAVAILABLE, FAN COOLERS, COMPONENT COOLING AND ELECTRIC BUSES 5A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	3.46×10^{-4}	All	Fails	No effect	No effect
Switch 7 is turned to on position and no recovery action.	4.72×10^{-5}	SI pumps stop	Fails	No effect	No effect
Hardware					
Single element cutsets:					
Pipe 60 rupture (8 inch) and failure to use pipe 190.	1.70×10^{-8}		Fails	No effect	No effect
Multiple Failures					
Mechanical failure in both recirculation pumps and operator error in switching to RHR pumps.	2.82×10^{-6}	Recirculation pumps 21 and 22 and all RHR subsystems	Fails	Containment spray recirculation	No effect

TABLE 1.5.2.3.4-16 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF HIGH HEAD RECIRCULATION WITH ELECTRIC BUSES 2A AND 3A UNAVAILABLE, FAN COOLERS, COMPONENT COOLING AND ELECTRIC BUSES 5A AND 6A AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
SI pumps 21 and 23 fail.	6.30×10^{-5}	SI pump 21 and 23	Fails	No effect	No effect
MOV 888A and 888B do not open and pipe 190 not used.	7.88×10^{-7}	MOVs 888A and 888B	Fails	No effect	No effect
Testing	NR*	NR*	No effect	NR*	No effect
Maintenance and Hardware					
Maintenance on one SI pump and mechanical failure of the other.	1.50×10^{-5}	All three SI pumps unavailable	Fails	No effect	No effect
Other Causes					
See Section 1.5.2.3.4.4.2 for details.	9.9×10^{-5}	SI pumps or MOVs 888	Fails	Cause dependent	Cause dependent
Total frequency of system failure.	6.00×10^{-4}				

*NR = not relevant.

TABLE 1.5.2.3.4-17

INDIAN POINT 2 - MINIMAL CUTSETS FOR THE FAULT TREE FOR LOW HEAD RECIRCULATION WHEN ALL THE HOUSE EVENTS ARE TREATED AS BASIC EVENTS

CUTSETS WITH 1 BASIC EVENT

1)	1)	UCCWFAIL

CUTSETS WITH 2 BASIC EVENTS

5)	1)	HPPLN6OE	ELCHDDIS	2)	HDISCHDN	ELDHDDIS	3)	UXV753AC	ECNT885A	4)	UXV753GC	ECNT885A
9)	5)	UXV753HC	ECNT885A	6)	UXV753BC	ECNT885A	7)	UXV753AC	EMV885AQ	8)	UXV753GC	EMV885AQ
13)	9)	UXV753HC	EMV885AQ	10)	UXV753BC	EMV885AQ	11)	UXV753AC	ECNT885B	12)	UXV753GC	ECNT885B
17)	13)	UXV753HC	ECNT885B	14)	UXV753BC	ECNT885B	15)	UXV753AC	EMV885BQ	16)	UXV753GC	EMV885BQ
21)	17)	UXV753HC	EMV885BQ	18)	UXV753BC	EMV885BQ	19)	ERECSUMP	ECNT885A	20)	ERECSUMP	EMV885AQ
25)	21)	ERECSUMP	ECNT885B	22)	ERECSUMP	EMV885BQ	23)	ERECSUMP	ECNT1805	24)	ERECSUMP	EMV1805C
29)	25)	UXV820BC	ECNT-746	26)	UXV818BC	ECNT-746	27)	UXV820BC	EMV-746Q	28)	UXV818BC	EMV-746Q
33)	29)	UXV820BC	ECNT-640	30)	UXV818BC	ECNT-640	31)	UXV820BC	EMV-640C	32)	UXV818BC	EMV-640C
37)	33)	UXV820BC	UXV820AC	34)	UXV818BC	UXV820AC	35)	UXV820BC	UXV818AC	36)	UXV818BC	UXV818AC
41)	37)	ERECSUMP	ECNT744-	38)	ERECSUMP	EMV744-C	39)	UXV753AC	ECNT1805	40)	UXV753GC	ECNT1805
45)	41)	UXV753HC	ECNT1805	42)	UXV753BC	ECNT1805	43)	UXV753AC	EMV1805C	44)	UXV753GC	EMV1805C
49)	45)	UXV753HC	EMV1805C	46)	UXV753BC	EMV1805C	47)	UXV753AC	ECNT744-	48)	UXV753GC	ECNT744-
53)	49)	UXV753HC	ECNT744-	50)	UXV753BC	ECNT744-	51)	UXV753AC	EMV744-C	52)	UXV753GC	EMV744-C
57)	53)	UXV753HC	EMV744-C	54)	UXV753BC	EMV744-C	55)	ECV-741C	UXV753AC	56)	ECNTSUMP	UXV753AC
61)	57)	ECV-741C	UXV753GC	58)	ECNTSUMP	UXV753GC	59)	ECV-741C	UXV753HC	60)	ECNTSUMP	UXV753HC
65)	61)	ECV-741C	UXV753BC	62)	ECNTSUMP	UXV753BC	63)	ECV-741C	ERECSUMP	64)	ECNTSUMP	ERECSUMP
69)	65)	UCNT822B	ECNT-746	66)	UMV822BQ	ECNT-746	67)	UCNT822B	EMV-746Q	68)	UMV822BQ	EMV-746Q
73)	69)	UCNT822B	ECNT-640	70)	UMV822BQ	ECNT-640	71)	UCNT822B	EMV-640C	72)	UMV822BQ	EMV-640C
77)	73)	UCNT822B	UXV820AC	74)	UMV822BQ	UXV820AC	75)	UCNT822B	UXV818AC	76)	UMV822BQ	UXV818AC
81)	77)	UCNT822A	UXV820BC	78)	UMV822AQ	UXV820BC	79)	UCNT822A	UXV818BC	80)	UMV822AQ	UXV818BC
85)	81)	UCNT822A	UCNT822B	82)	UMV822AQ	UCNT822B	83)	UCNT822A	UMV822BQ	84)	UMV822AQ	UMV822BQ
89)	85)	ECNT802A	JBS226BD	86)	EMV802AQ	JBS226BD	87)	UXV753AC	JBS226BD	88)	UXV753GC	JBS226BD
93)	89)	UXV753HC	JBS226BD	90)	UXV753BC	JBS226BD	91)	ERECSUMP	JBS226BD	92)	JBS226BD	ECNT-746
97)	93)	JBS226BD	EMV-746Q	94)	JBS226BD	ECNT-640	95)	JBS226BD	EMV-640C	96)	JBS226BD	UXV820AC
101)	97)	JBS226BD	UXV818AC	98)	UCNT822A	JBS226BD	99)	UMV822AQ	JBS226BD	100)	ELOHDDIS	JBS226BD
105)	101)	UXV751AC	JBS26A-D	102)	ECV886AC	JBS26A-D	103)	UXV752AC	JBS26A-D	104)	ECNT802A	JBS26A-D
109)	105)	EMV802AQ	JBS26A-D	106)	EPMRC21S	JBS26A-D	107)	EMORC21S	JBS26A-D	108)	ECNTRC21	JBS26A-D
113)	109)	UXV753AC	JBS26A-D	110)	UXV753GC	JBS26A-D	111)	UXV753HC	JBS26A-D	112)	UXV753BC	JBS26A-D
117)	113)	ERECSUMP	JBS26A-D	114)	ECNT745A	JBS226AD	115)	EMV745AC	JBS226AD	116)	ECNT802B	JBS226AD
121)	117)	EMV802BQ	JBS226AD	118)	UXV753AC	JBS226AD	119)	UXV753GC	JBS226AD	120)	UXV753HC	JBS226AD
125)	121)	UXV753BC	JBS226AD	122)	ERECSUMP	JBS226AD	123)	JBS226AD	UXV820BC	124)	JBS226AD	UXV818BC
129)	125)	ECNT745B	JBS226AD	126)	EMV745BC	JBS226AD	127)	JBS226AD	UCNT822B	128)	JBS226AD	UMV822BC
133)	129)	JBS226AD	JBS226BD	130)	JBS26A-D	JBS226AD	131)	ECNT745A	JBS25A-D	132)	EMV745AC	JBS25A-D

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TABLE 1.5.2.3.4-18

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF LOW HEAD RECIRCULATION WITH FAN COOLERS UNAVAILABLE, COMPONENT COOLING AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	4.75×10^{-3}	NR*	Fails	No effect	No effect
Switch 6 in addition to 7 is turned to "on" position and no recovery actions are taken.	5.26×10^{-4}	MOVs 746 and 747 close	Fails	No effect	No effect
Hardware					
Single element cutsets.		There are no single element cutsets	Partial failure	No effect	No effect
Multiple Failures					
Hardware failure in both recirculation pumps and operator error in switching to RHR pumps.	3.82×10^{-5}	Recirculation pumps 21 and 22 and all RHR subsystems	Fails	Containment spray recirculation	No effect

*NR = not relevant.

TABLE 1.5.2.3.4-18 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF LOW HEAD RECIRCULATION WITH FAN COOLERS UNAVAILABLE, COMPONENT COOLING AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Hardware failure in both MOVs 1802A and B and operator error in switching to RHR pumps.	1.71×10^{-6}	MOVs 1802A and 1802B and RHR subsystem	Fails	Containment spray recirculation	No effect
MOVs 822B and 746 fail to open and the containment spray recirculation is not used to cool the sump water.	6.57×10^{-6}	MOVs 822B and 746	Fails	No effect	No effect
MOVs 822B and 822A fail to open.	6.57×10^{-6}	MOVs 822B and 822A	Fails	Containment spray recirculation	No effect
Testing	NR*	NR*	No effect	No effect	No effect
Maintenance and Hardware					
Maintenance on one SI pump (see Section 1.5.2.3.4.5.2.1.4 for detail.)	$<<10^{-8}$	See Section 1.5.2.3.4.5.2.1.4 for details	Fails	No effect	No effect

*NR = not relevant.

TABLE 1.5.2.3.4-18 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF LOW HEAD RECIRCULATION WITH FAN COOLERS UNAVAILABLE, COMPONENT COOLING AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Other Causes See Section 1.5.2.3.4.5.2.1.5 for details	9.8×10^{-5}	See Section 1.5.2.3.4.5.2.1.5 for details	Fails	Containment spray recirculation fails	Cause dependent
Total frequency of system failure.	5.43×10^{-3}				

TABLE 1.5.2.3.4-19

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF LOW HEAD RECIRCULATION WITH FAN COOLERS, COMPONENT COOLING, AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Failure to initiate switchover.	4.75×10^{-3}	All	Fails	No effect	No effect
Switch 6 in addition to 7 is turned to "on" position and no recovery actions are taken.	5.26×10^{-4}	MOVs 746 and 747 close	Fails	No effect	No effect
Hardware					
Single element cutsets.		There are no single element cutsets	Partial	No effect	No effect
Multiple Failures					
Hardware failure in both recirculation pumps and operator error in switching to RHR pumps.	4.86×10^{-5}	Recirculation pumps 21 and 22 and all RHR subsystems	Fails	Containment spray recirculation	No effect

TABLE 1.5.2.3.4-19 (continued)

INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF LOW HEAD RECIRCULATION WITH FAN COOLERS, COMPONENT COOLING, AND ALL ELECTRIC BUSES AVAILABLE

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Hardware failure in both MOVs 1802A and B and operator error in switching to RHR pumps.	1.71×10^{-6}	MOVs 1802A and 1802B and RHR	Fails	Containment spray recirculation fails	No effect
Testing	NR*	NR*	No effect	No effect	No effect
Maintenance and Hardware					
Maintenance on one SI pump(see Section 1.5.2.3.4.5.2.1.4 for details.)	$<< 10^{-8}$	See Section 1.5.2.3.4.5.2.1.4 for details	Fails	No effect	No effect
Other Causes					
See Section 1.5.2.3.4.5.2.1.5 for details.	6.6×10^{-5}	See Section 1.5.2.3.4.5.2.1.5 for details	Fails	Containment spray recirculation fails	Cause dependent
Total frequency of system failure.	5.43×10^{-3}				

*NR = not relevant.

TABLE 1.5.2.3.4-20

INDIAN POINT 2 - MINIMAL CUTSETS FOR CONTAINMENT SPRAY RECIRCULATION
WHEN ALL HOUSE EVENTS ARE TREATED AS BASIC EVENTS

CUTSETS WITH 1 BASIC EVENT

1)	1)	UCCWFAIL

CUTSETS WITH 2 BASIC EVENTS

5)	1)	CCNT889A	CCNT889B	2)	CMV889AQ	CCNT889B	3)	CCNT889A	CMV889BQ	4)	CMV889AQ	CMV889BQ
9)	5)	ERECSUMP	ECNT885A	6)	ERECSUMP	EMV885AQ	7)	ERECSUMP	ECNT1805	8)	ERECSUMP	EMV1805C
13)	9)	ERECSUMP	ECNT885B	10)	ERECSUMP	EMV885BQ	11)	ERECSUMP	ECV-741C	12)	ERECSUMP	ECNTSUMP
17)	13)	UXV820BC	UXV820AC	14)	UXV818BC	UXV820AC	15)	EXV-742C	UXV820AC	16)	UXV820BC	UXV818AC
21)	17)	UXV818BC	UXV818AC	18)	EXV-742C	UXV818AC	19)	UXV820BC	UCNT822A	20)	UXV818BC	UCNT822A
25)	21)	EXV-742C	UCNT822A	22)	UXV820BC	UMV822AQ	23)	UXV818BC	UMV822AQ	24)	EXV-742C	UMV822AQ
29)	25)	ECNT744-	ERECSUMP	26)	EMV744-Q	ERECSUMP	27)	UCNT822B	UXV820AC	28)	UMV822BQ	UXV820AC
33)	29)	UCNT822B	UXV818AC	30)	UMV822BQ	UXV818AC	31)	UCNT822B	UCNT822A	32)	UMV822BQ	UCNT822A
37)	33)	UCNT822B	UMV822AQ	34)	UMV822BQ	UMV822AQ	35)	ERECSUMP	JBS226BD	36)	ECNT802A	JBS226BD
41)	37)	EMV802AQ	JBS226BD	38)	CCNT889A	JBS226BD	39)	CMV889AQ	JBS226BD	40)	UXV820AC	JBS226BD
45)	41)	UXV818AC	JBS226BD	42)	UCNT822A	JBS226BD	43)	UMV822AQ	JBS226BD	44)	UXV751AC	JBS26A-D
49)	45)	ECV886AC	JBS26A-D	46)	UXV752AC	JBS26A-D	47)	ERECSUMP	JBS26A-D	48)	4BS221-D	JBS26A-D
53)	49)	EPMRC21S	JBS26A-D	50)	EMORC21S	JBS26A-D	51)	ECNTRC21	JBS26A-D	52)	ECNT802A	JBS26A-D
57)	53)	EMV802AQ	JBS26A-D	54)	CCNT889A	JBS26A-D	55)	CMV889AQ	JBS26A-D	56)	UXV820AC	JBS26A-D
61)	57)	UXV818AC	JBS26A-D	58)	UCNT822A	JBS26A-D	59)	UMV822AQ	JBS26A-D	60)	ECNT745A	JBS226AD
65)	61)	EMV745AC	JBS226AD	62)	UXV820BC	JBS226AD	63)	UXV818BC	JBS226AD	64)	EXV-742C	JBS226AD
69)	65)	ECNT802B	JBS226AD	66)	EMV802BQ	JBS226AD	67)	JBS226AD	ERECSUMP	68)	UCNT822B	JBS226AD
73)	69)	UMV822BQ	JBS226AD	70)	ECNT745B	JBS226AD	71)	EMV745BC	JBS226AD	72)	CCNT889B	JBS226AD
77)	73)	CMV889BQ	JBS226AD	74)	JBS226AD	JBS226BD	75)	JBS226AD	JBS26A-D	76)	JBS25A-D	UXV751BC
81)	77)	JBS25A-D	ECV886BC	78)	JBS25A-D	UXV752BC	79)	ECNT745A	JBS25A-D	80)	EMV745AC	JBS25A-D
85)	81)	UXV820BC	JBS25A-D	82)	UXV818BC	JBS25A-D	83)	EXV-742C	JBS25A-D	84)	ECNT802B	JBS25A-D
89)	85)	EMV802BQ	JBS25A-D	86)	EPMRC22S	JBS25A-D	87)	EMORC22S	JBS25A-D	88)	ECNTRC22	JBS25A-D
93)	89)	JBS25A-D	ERECSUMP	90)	UCNT822B	JBS25A-D	91)	UMV822BQ	JBS25A-D	92)	ECNT745B	JBS25A-D
97)	93)	EMV745BC	JBS25A-D	94)	CCNT889B	JBS25A-D	95)	CMV889BQ	JBS25A-D	96)	JBS25A-D	JBS226BD
101)	97)	JBS25A-D	JBS26A-D	98)	UXV751AC	4BS222-D	99)	ECV886AC	4BS222-D	100)	UXV752AC	4BS222-D
105)	101)	4BS221-D	4BS222-D	102)	EPMRC21S	4BS222-D	103)	EMORC21S	4BS222-D	104)	ECNTRC21	4BS222-D
107)	105)	ERECSUMP	4BS222-D	106)	4BS222-D	JBS25A-D						

TABLE 1.5.2.3.4-21

INDIAN POINT 2 - MINIMAL CUTSETS FOR CONTAINMENT SPRAY RECIRCULATION
WHEN ALL HOUSE EVENTS ARE TREATED AS BASIC EVENTS
AND CORE COOLING RECIRCULATION IS AVAILABLE

CUTSETS WITH 1 BASIC EVENT:

1)	1)	UCCWFAIL

CUTSETS WITH 2 BASIC EVENTS:

3)	1)	CCNT889A	CCNT889B	2)	CMV889AQ	CCNT889B
5)	3)	CCNT889A	CMV889BQ	4)	CMV889AQ	CMV889BQ
7)	5)	CCNT889A	JBS226BD	6)	CMV889AQ	JBS226BD
9)	7)	CCNT889B	JBS226AD	8)	CMV889CQ	JBS226AD
11)	9)	CCNT889A	JBS26A-D	10)	CMV889AQ	JBS26A-D
13)	11)	CCNT889B	JBS25A-D	12)	CMV889BQ	JBS25A-D

TABLE 1.5.2.3.4-22

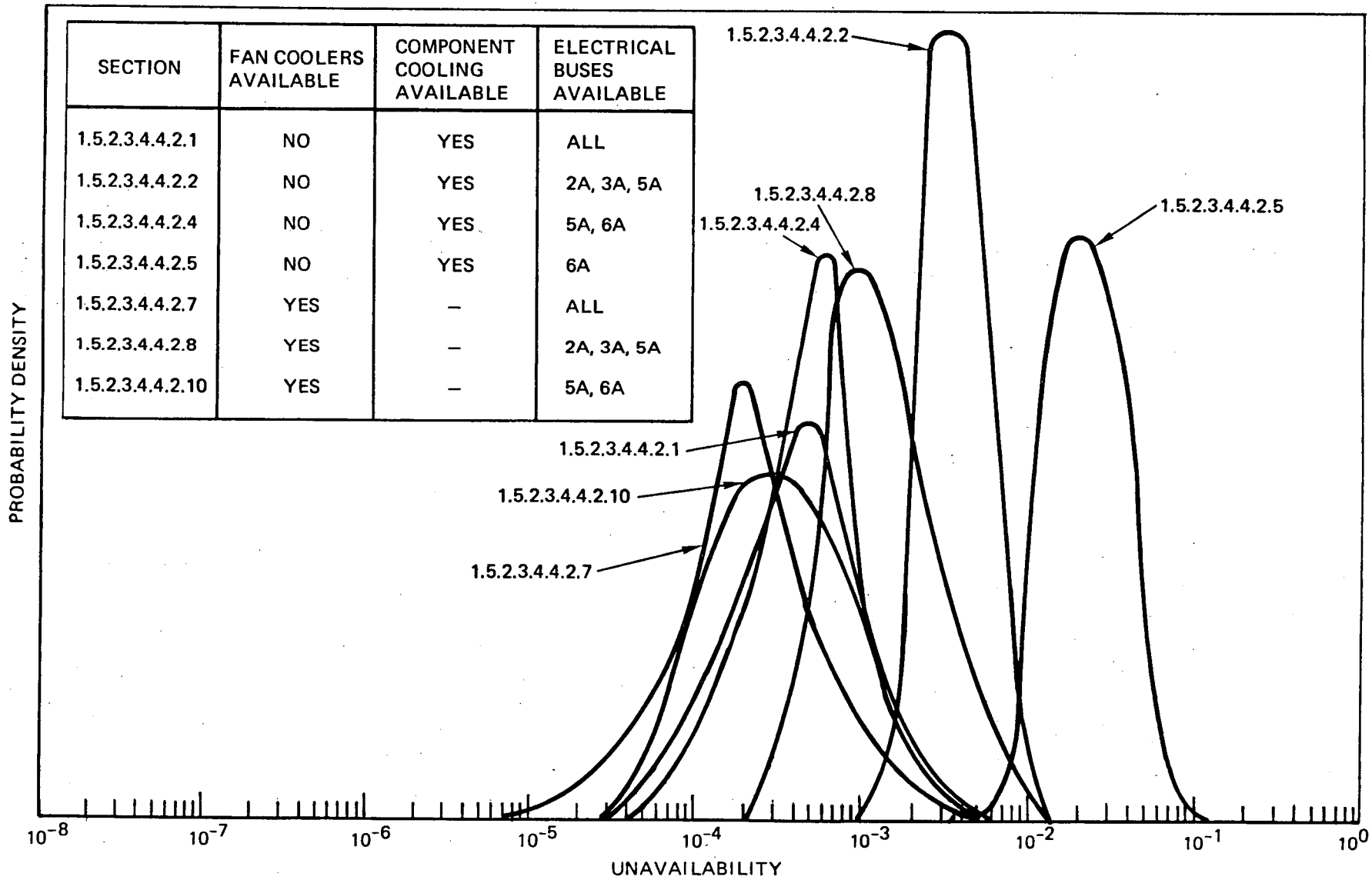
INDIAN POINT 2 - CAUSES AND FREQUENCY OF FAILURE OF CONTAINMENT SPRAY RECIRCULATION WHEN LARGE LOCA HAS OCCURRED AND ALL ELECTRIC BUSES ARE AVAILABLE
(Core Cooling Recirculation Successful)

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Operators fail to open isolation valves.	1.50×10^{-3}	MOVs 889A and 889B	Fails	No Effect	No Effect
Hardware					
Single events.	-	There are no single element cutsets	Partial failure	No effect	No effect
Multiple events:					
Both MOVs 889 fail to open.	6.57×10^{-6}	MOVs 889A and 889B	Fails	No effect	No effect
Testing	-	-	No effect	-	-
Maintenance	-	-	No effect	-	
Other Causes					
(See Section 1.5.2.3.4.6.2.1.5 for details)	3.23×10^{-5}	(see Section 1.5.2.3.4.6.2.1.5)	Fails	Cause dependent	Cause dependent
Total frequency of system failure.	1.50×10^{-3}				

TABLE 1.5.2.3.4-23

INDIAN POINT 2 - CAUSES AND FREQUENCIES OF FAILURE OF CONTAINMENT SPRAY RECIRCULATION WHEN LARGE LOCA HAS OCCURRED AND ELECTRIC BUS 5A (OR 6A) IS UNAVAILABLE
(Core Cooling Recirculation Successful)

Cause	Mean	Effects			
		Component	System	Other Systems	Initiating Event
Operator Error					
Operators fail to open isolation valves.	1.50×10^{-3}	MOVs 889B (or 889A)	Fails	No effect	No effect
Hardware					
Single Events:					
MOV 889B (or 889A) fails to open	2.31×10^{-3}	MOV 889B (or 889A)	Fails	No effect	No effect
Testing	NA		No effect		
Maintenance	NA		No effect		
Other Causes					
(See Section 1.5.2.3.4.6.2.2.5 for details.)	NA	(See Section 1.5.2.3.4.6.2.2.5)	Fails	Cause dependent	Cause dependent
Total frequency of system failure.	3.80×10^{-3}				



SECTION	FAN COOLERS AVAILABLE	COMPONENT COOLING AVAILABLE	ELECTRICAL BUSES AVAILABLE
1.5.2.3.4.4.2.1	NO	YES	ALL
1.5.2.3.4.4.2.2	NO	YES	2A, 3A, 5A
1.5.2.3.4.4.2.4	NO	YES	5A, 6A
1.5.2.3.4.4.2.5	NO	YES	6A
1.5.2.3.4.4.2.7	YES	–	ALL
1.5.2.3.4.4.2.8	YES	–	2A, 3A, 5A
1.5.2.3.4.4.2.10	YES	–	5A, 6A

Figure 1.5.2.3.4-1. Probability Distribution of Indian Point 2 High Head Recirculation Unavailability

SECTION	FAN COOLERS AVAILABLE	COMPONENT COOLING AVAILABLE	ELECTRICAL BUSES AVAILABLE
1.5.2.3.4.5.2.1	NO	YES	ALL
1.5.2.3.4.5.2.2	NO	YES	2A, 3A, 5A
1.5.2.3.4.5.2.4	NO	YES	5A, 6A

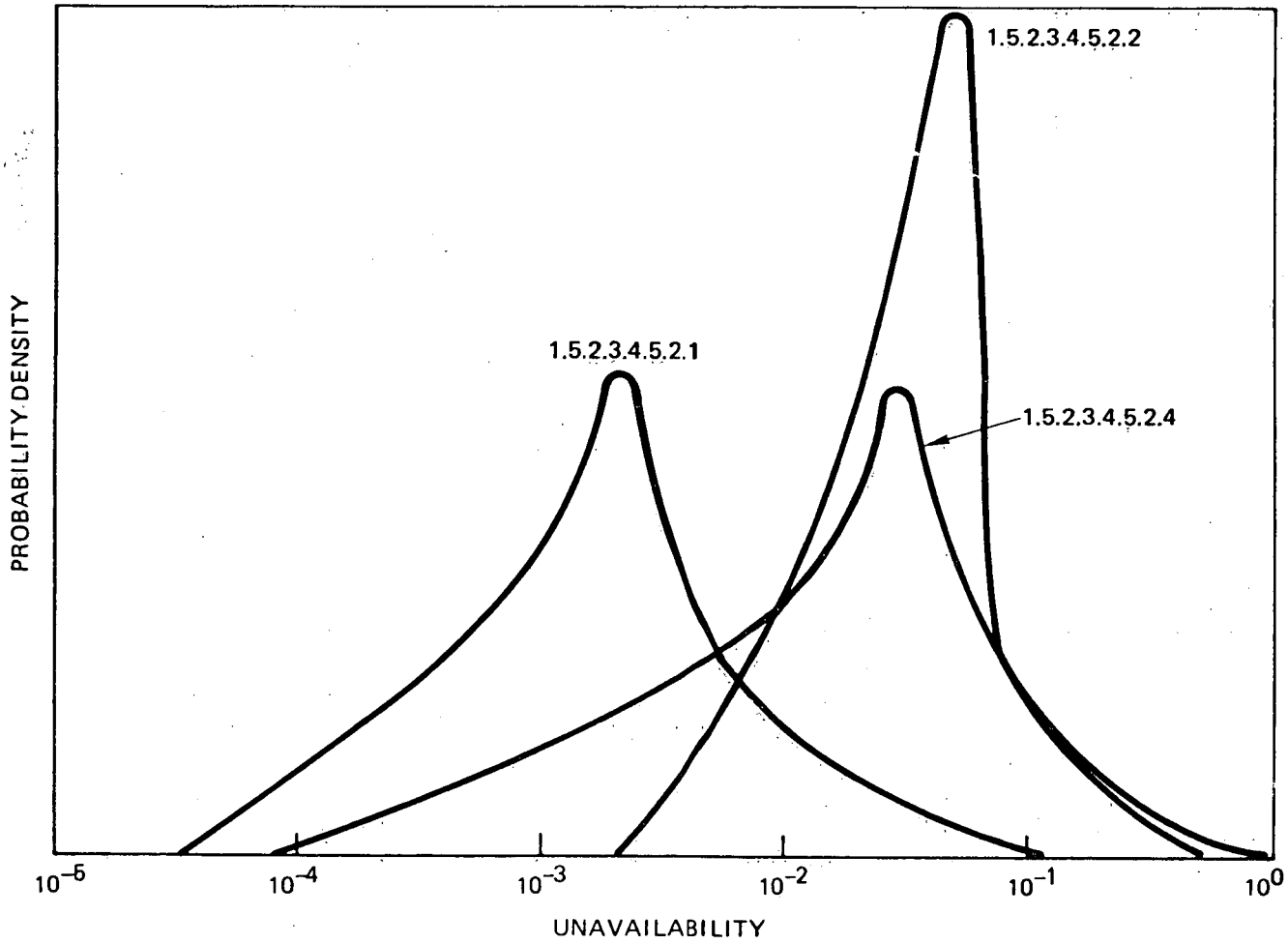


Figure 1.5.2.3.4-2. Probability Distribution of Indian Point 2 Low Head Recirculation Unavailability

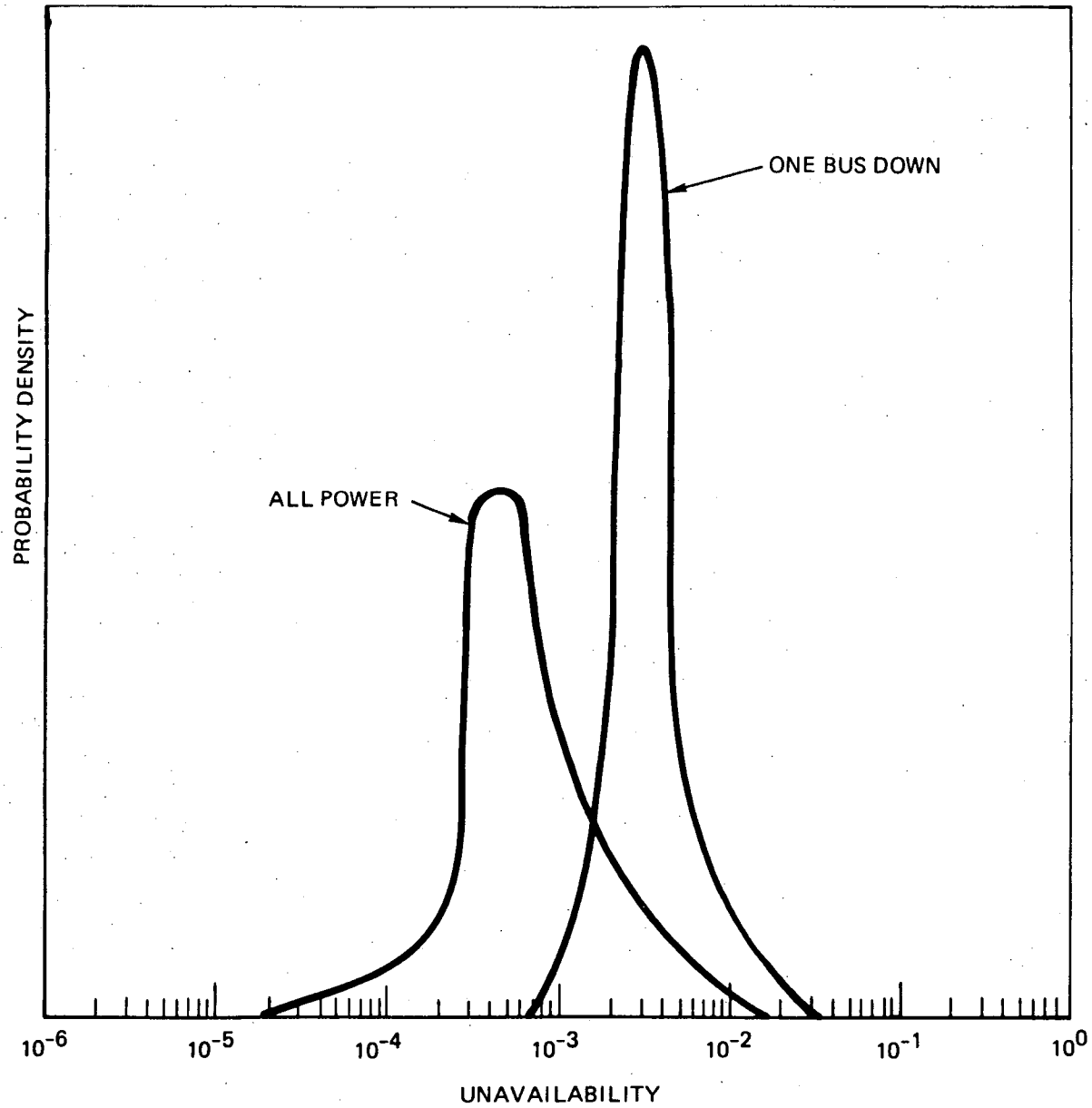


Figure 1.5.2.3.4-3. Probability Distribution of Indian Point 2 Containment Spray Recirculation Unavailability

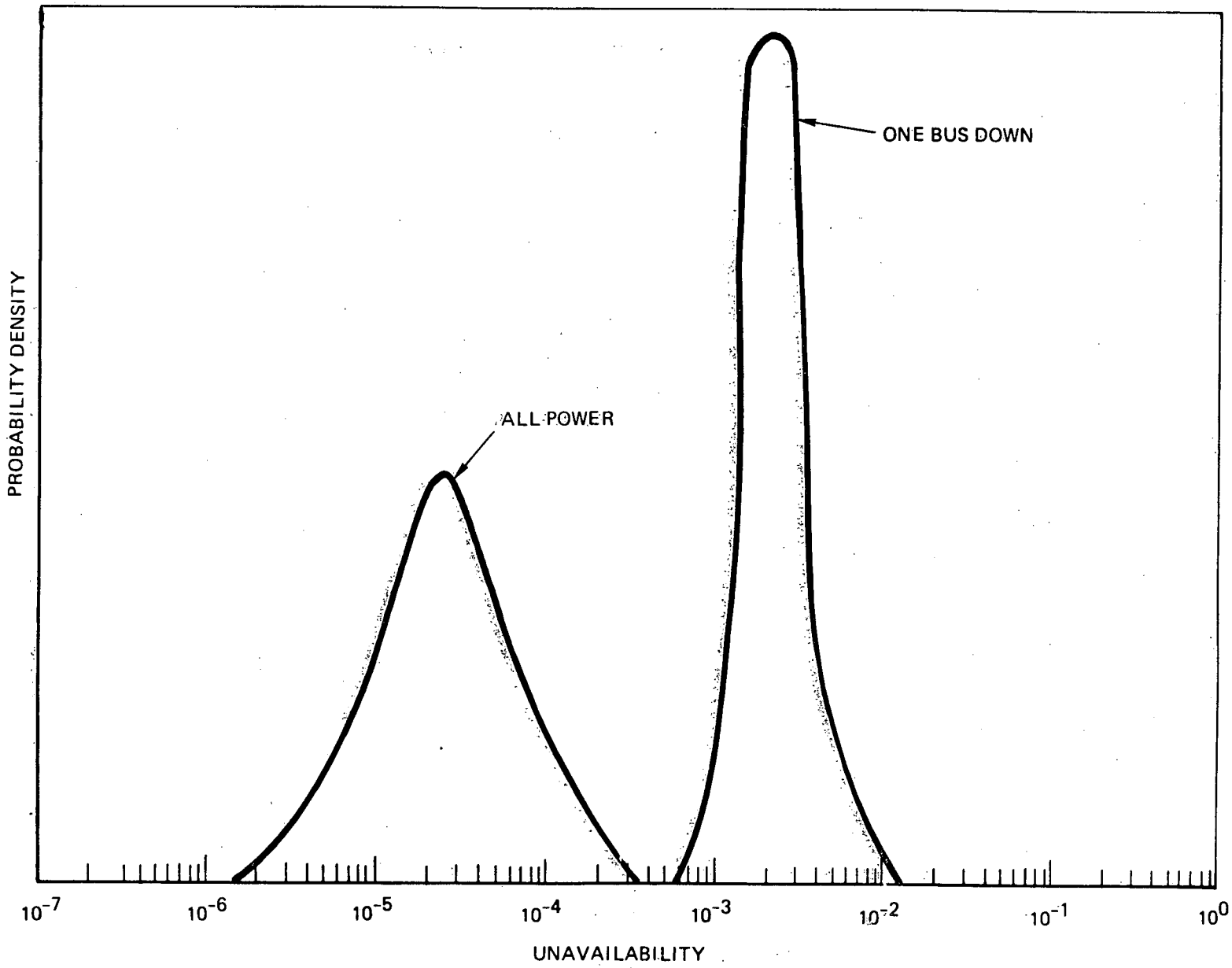


Figure 1.5.2.3.4-4. Probability Distribution of Indian Point 2 Hot Leg Recirculation Unavailability

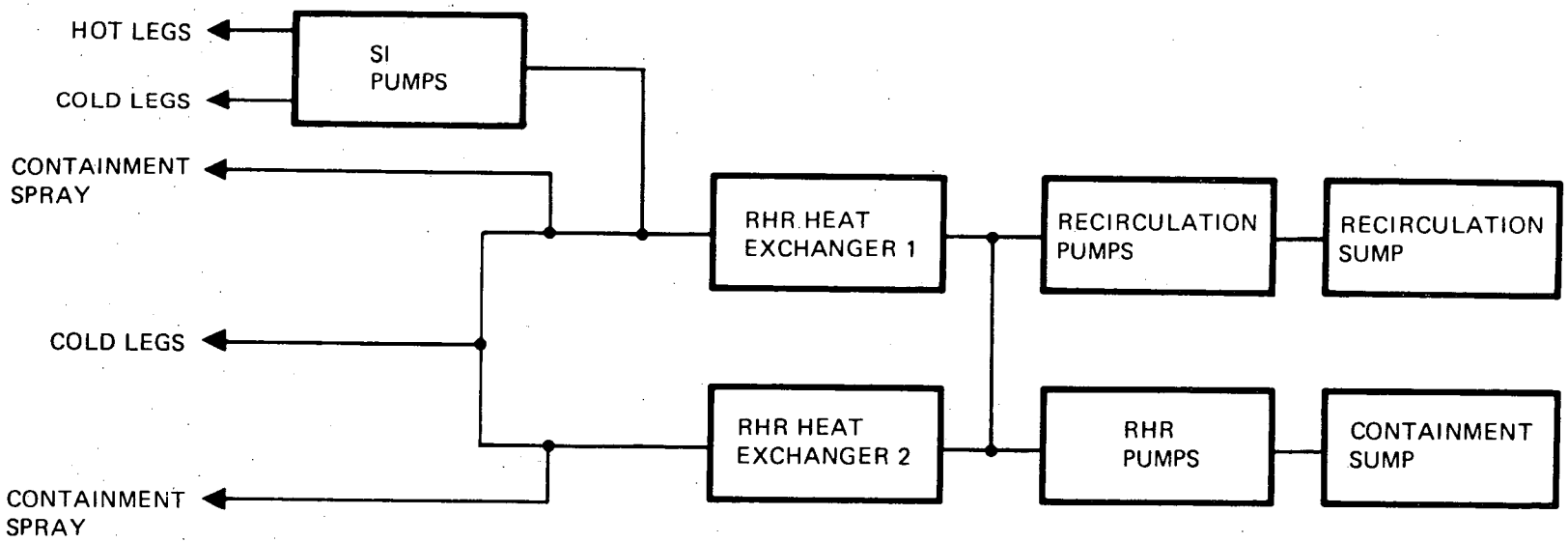


Figure 1.5.2.3.4-5. Indian Point 2 Recirculation System Block Diagram

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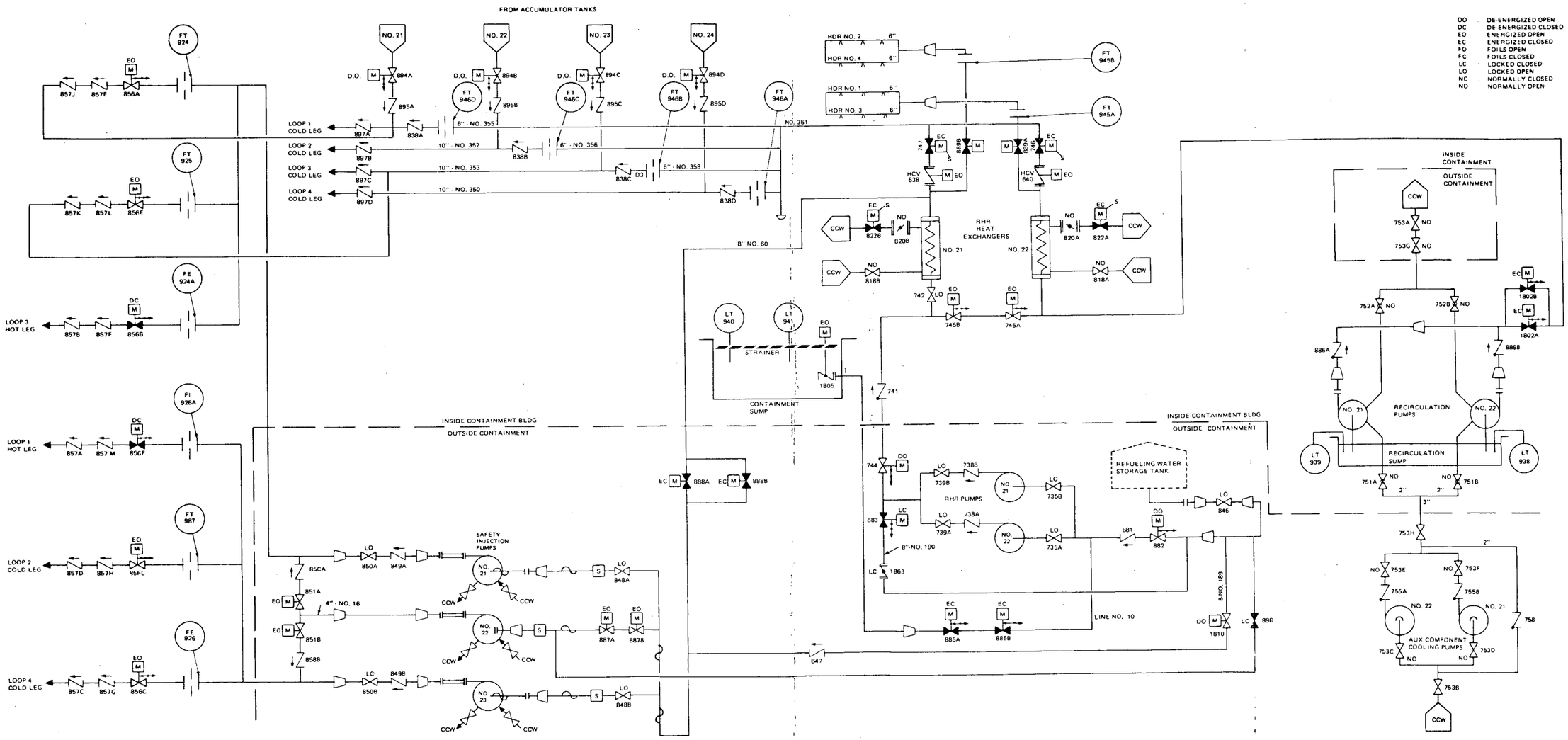


Figure 1.5.2.3.4-6. Indian Point 2 Recirculation System Simplified P&ID

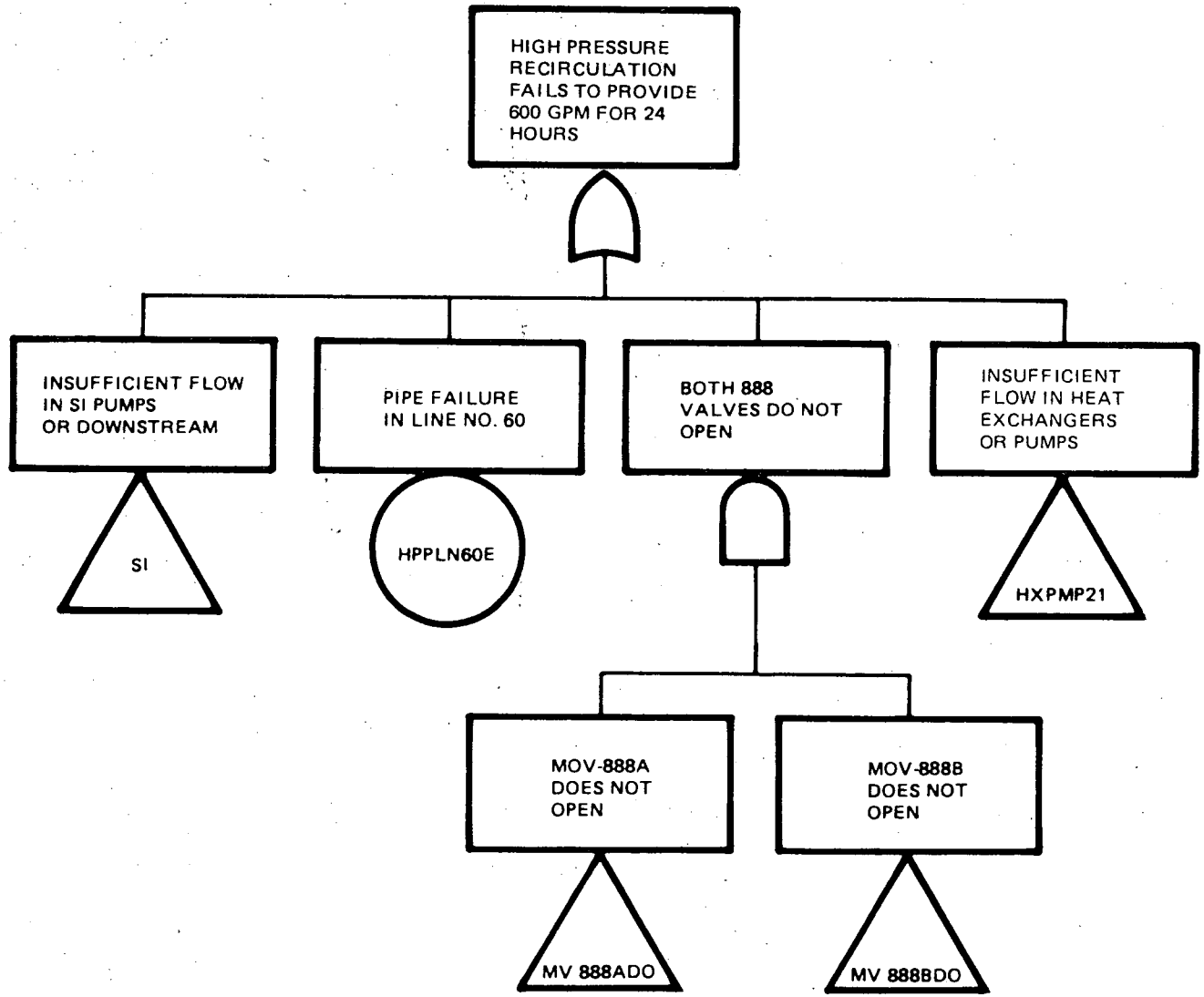


Figure 1.5.2.3.4-7. Indian Point 2 Top Structure of the Fault Tree for High Head Recirculation

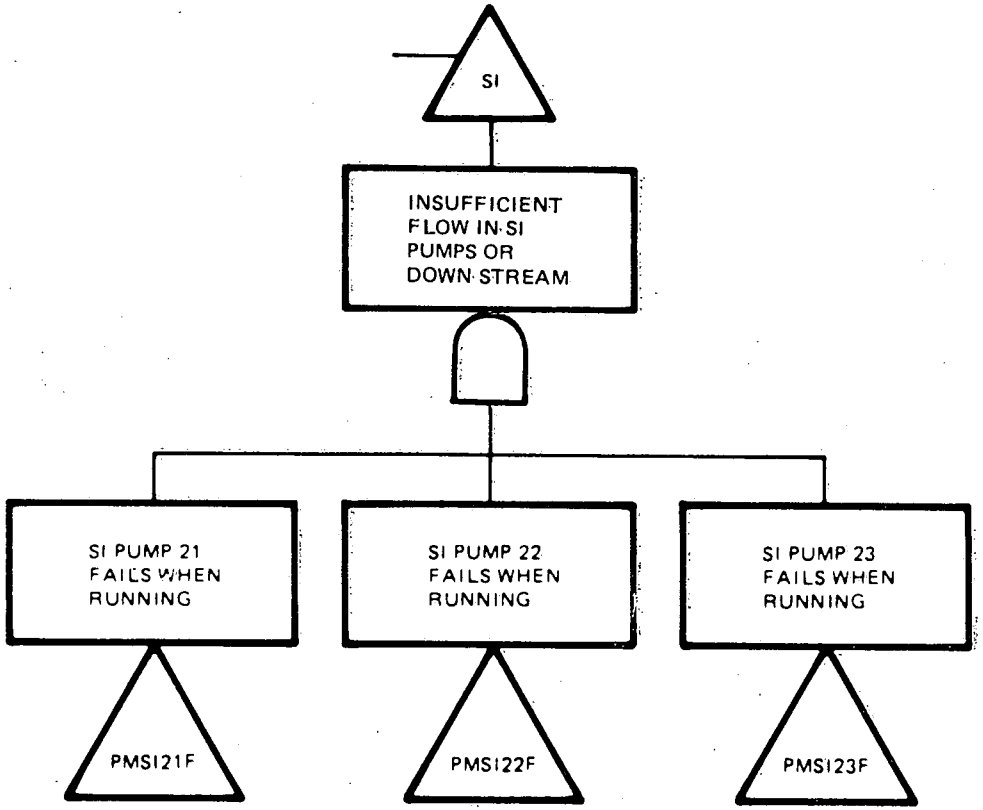
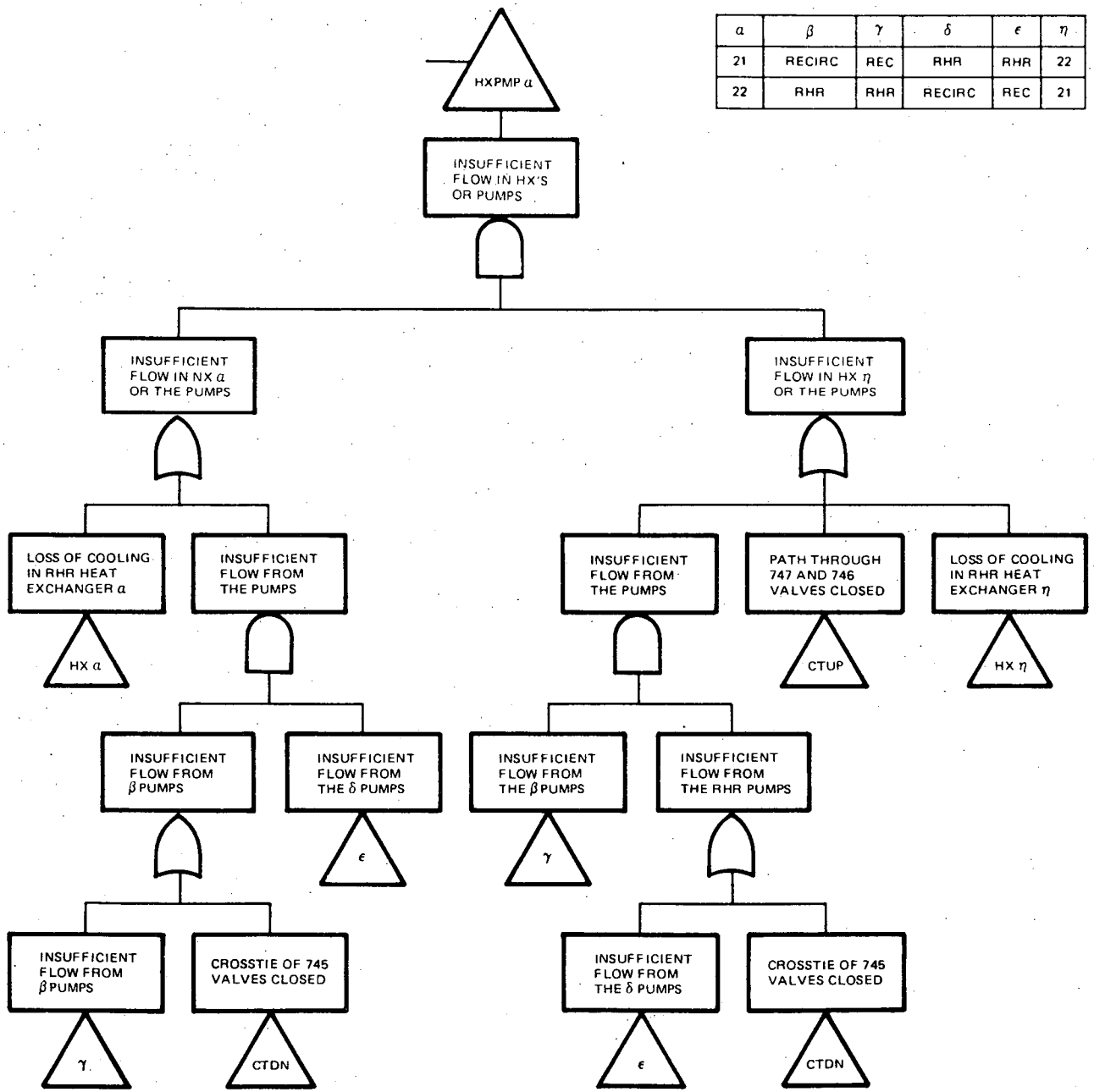
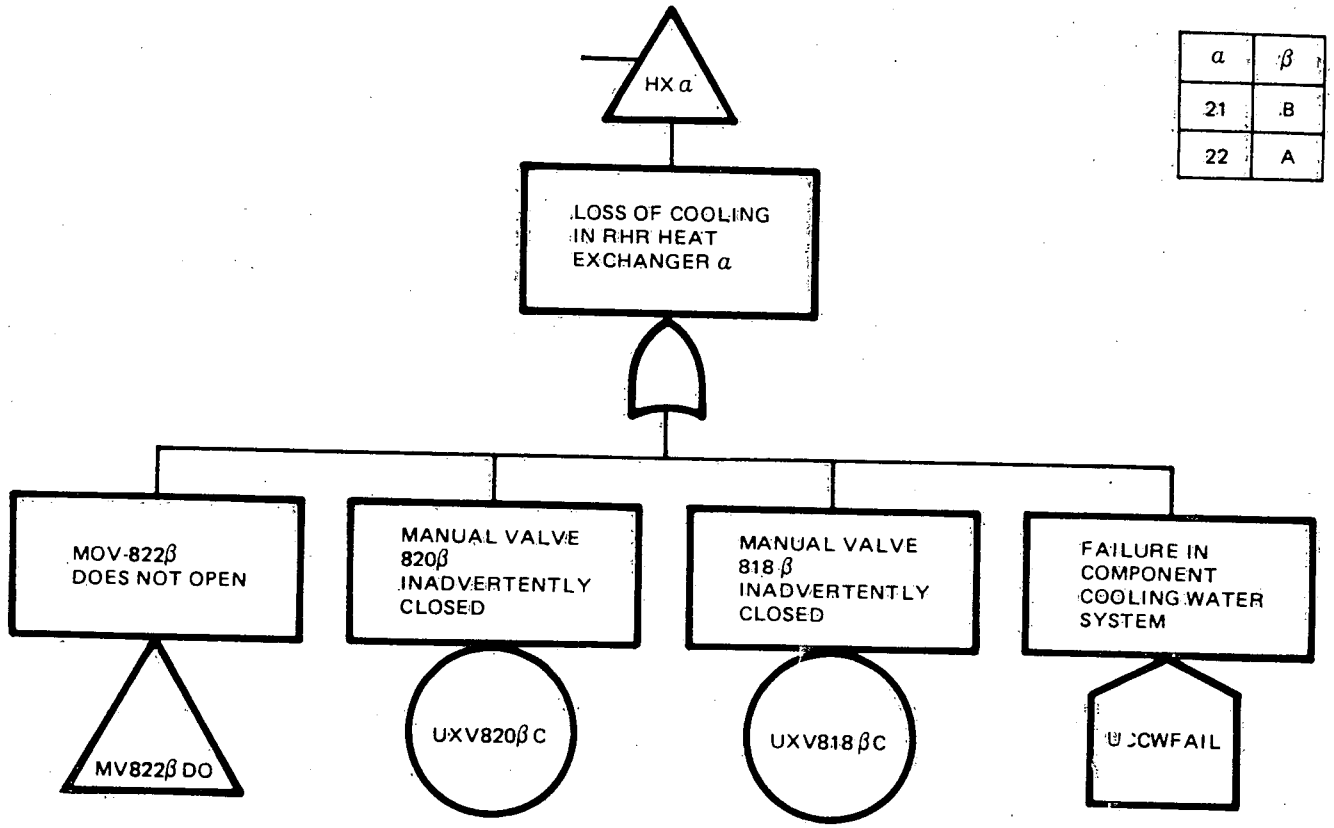


Figure 1.5.2.3.4-8. Indian Point 2 Fault Tree for All SI Pumps Unavailable



α	β	γ	δ	ε	η
21	RECIRC	REC	RHR	RHR	22
22	RHR	RHR	RECIRC	REC	21

Figure 1.5.2.3.4-9. Indian Point 2 Fault Tree for Insufficient Flow at Both Heat Exchanger Outlets



α	β
21	B
22	A

Figure 1.5.2.3.4-10. Indian Point 2 Fault Tree for Loss of Cooling in a Heat Exchanger

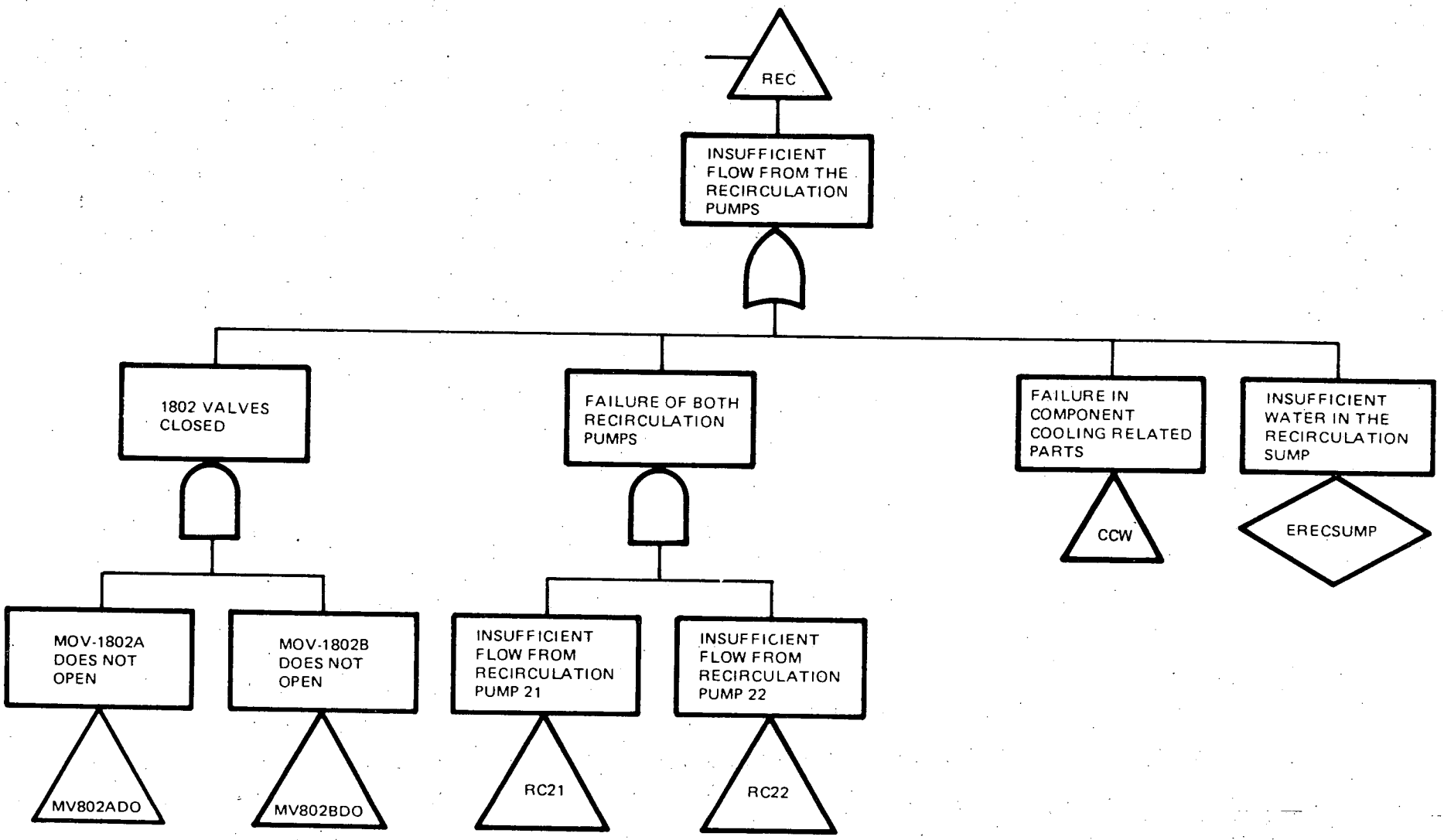


Figure 1.5.2.3.4-11. Indian Point 2 Fault Tree for Insufficient Flow from the Recirculation Pumps

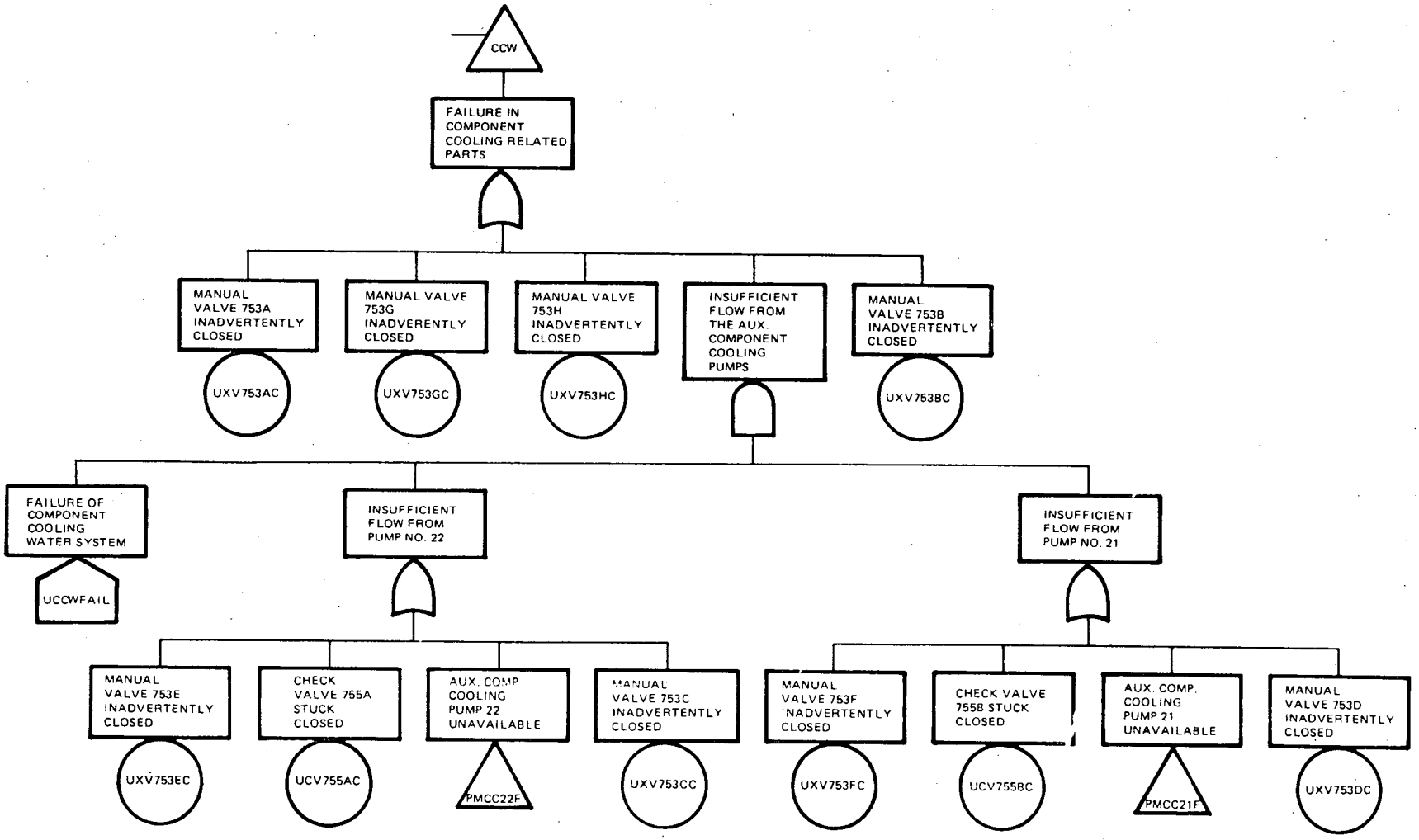


Figure 1.5.2.3.4-12. Indian Point 2 Fault Tree for the Failure of Component Cooling to the Recirculation Pumps

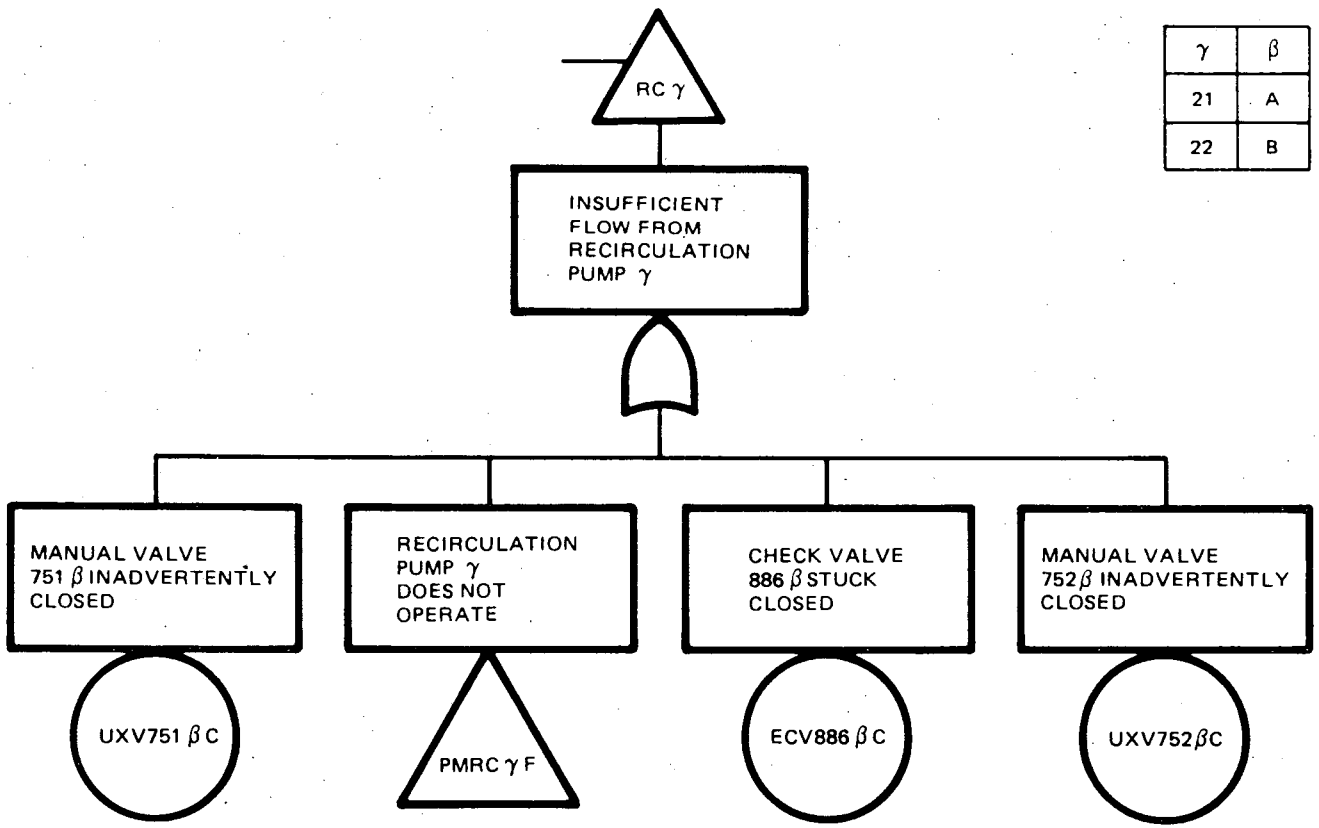


Figure 1.5.2.3.4-13. Indian Point 2 Fault Tree for Failures in One Recirculation Pump Train

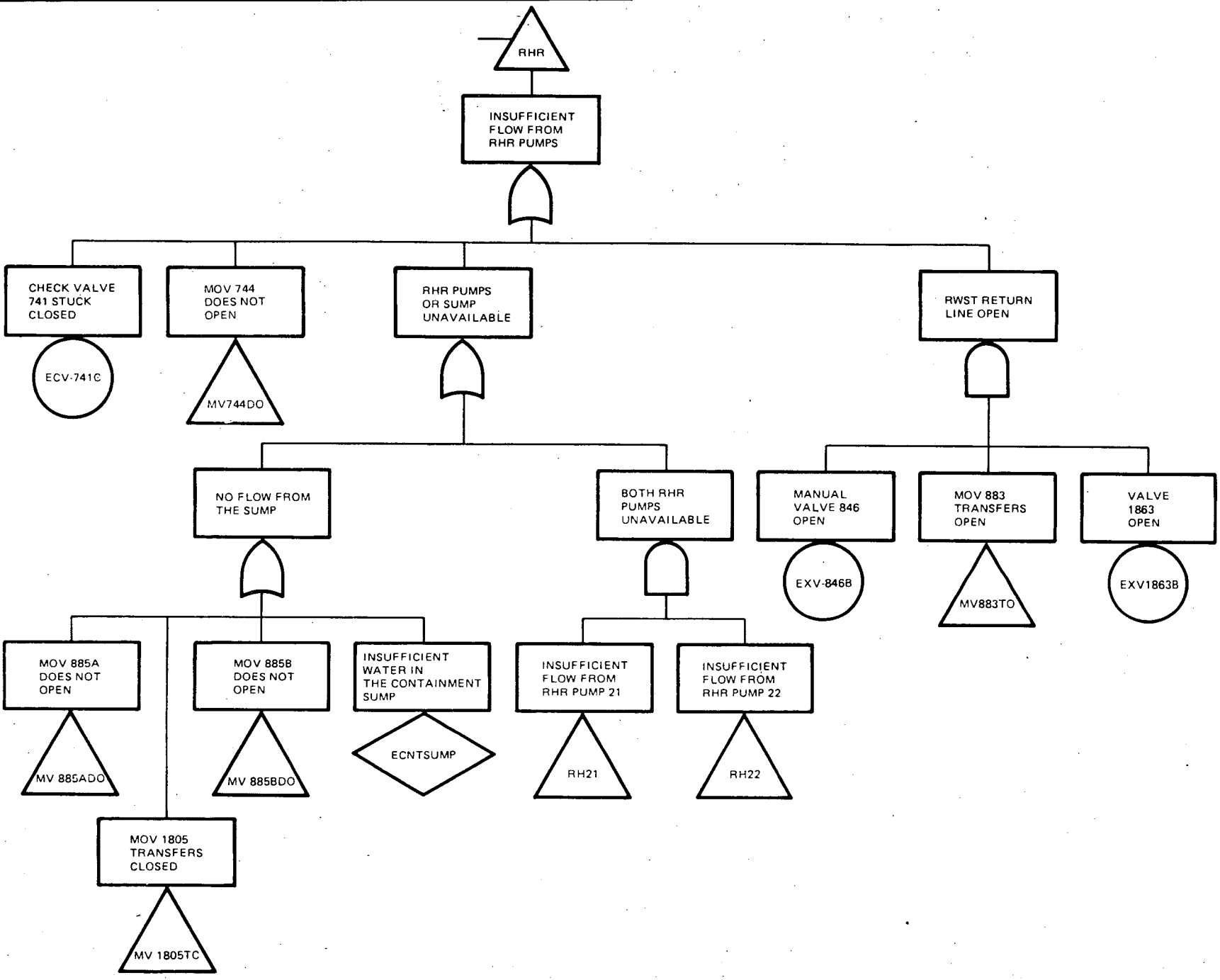


Figure 1.5.2.3.4-14. Indian Point 2 Fault Tree for Insufficient Flow from the RHR Pumps

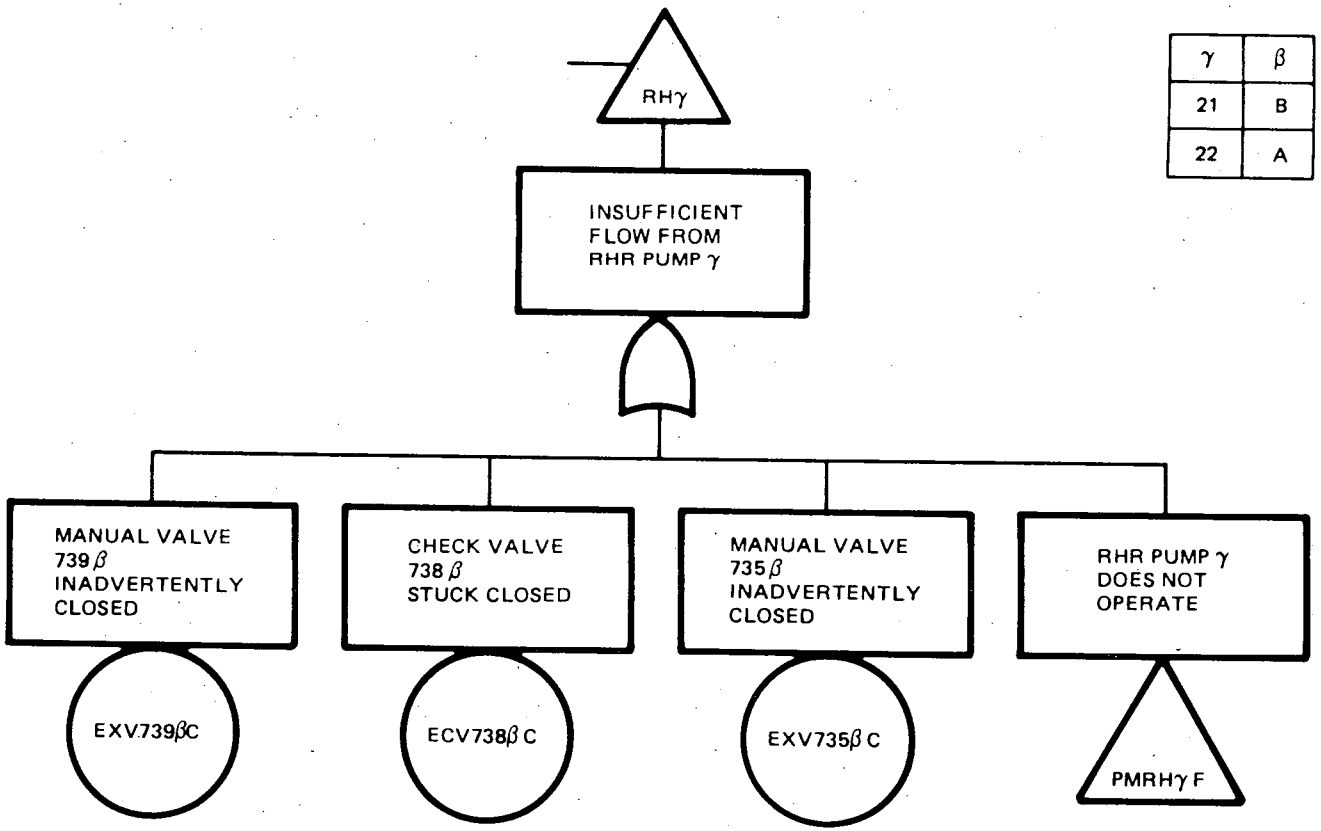


Figure 1.5.2.3.4-15. Indian Point 2 Fault Tree for Failures in One RHR Train

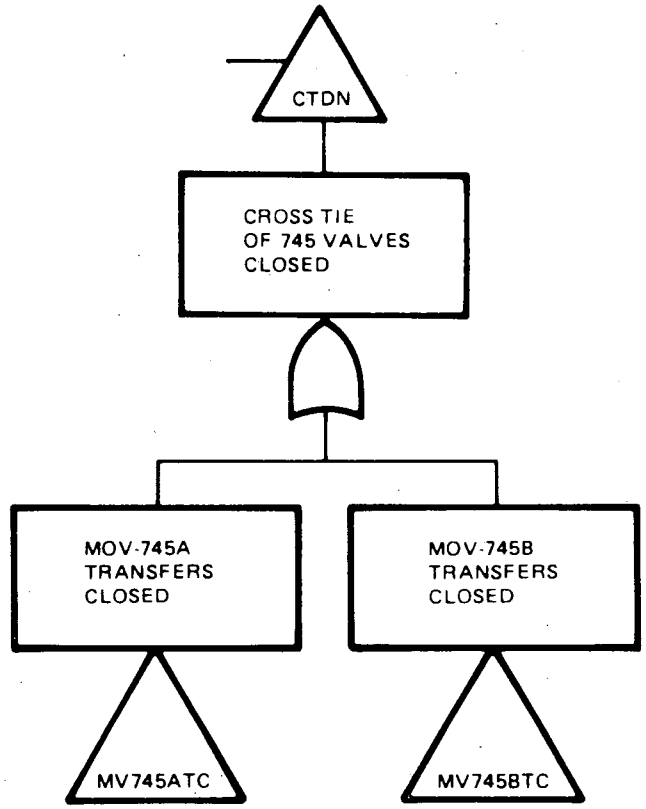


Figure 1.5.2.3.4-16. Indian Point 2 Fault Tree for Blockage of Crosstie Between the Two Heat Exchanger Suction Lines

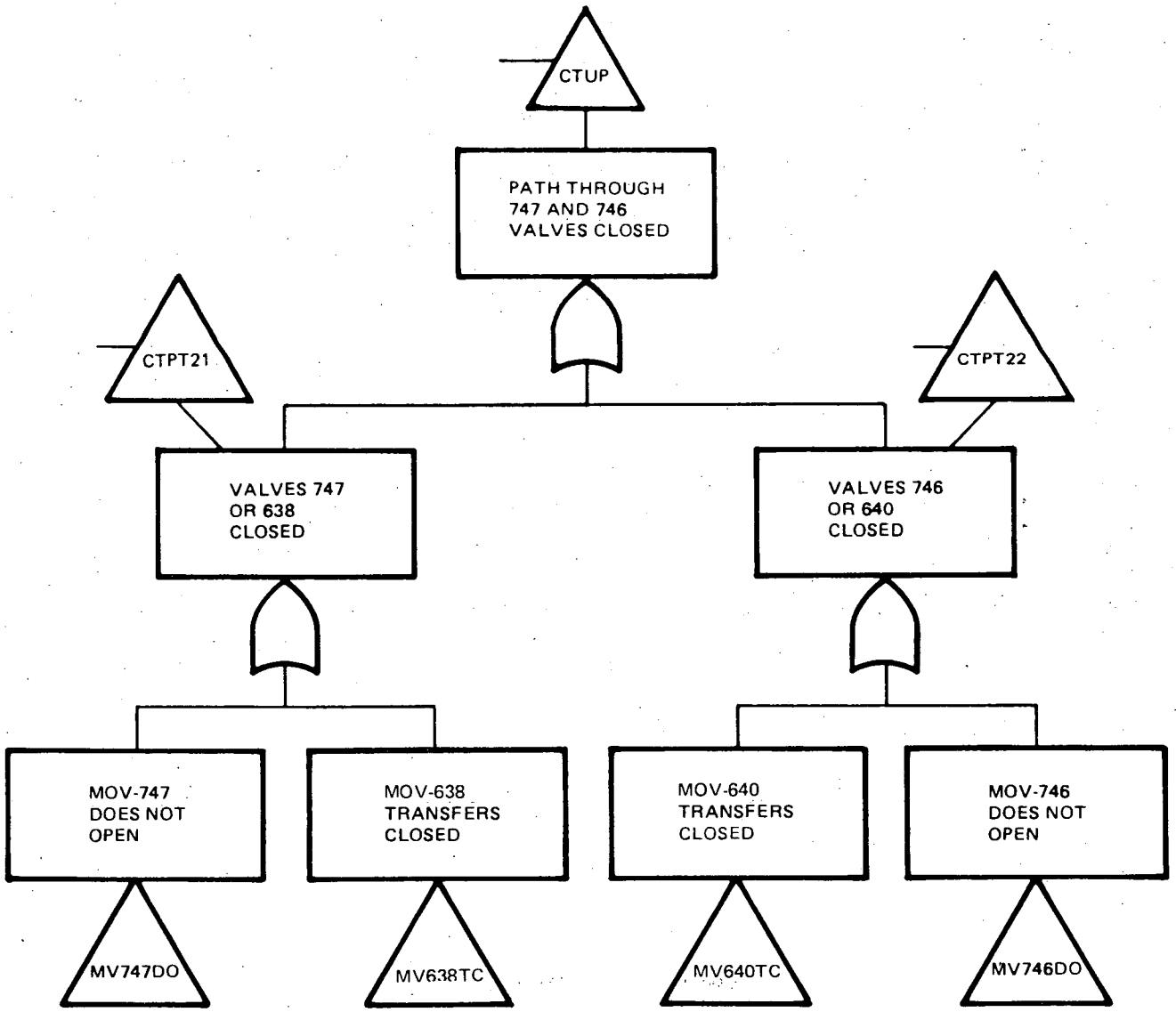
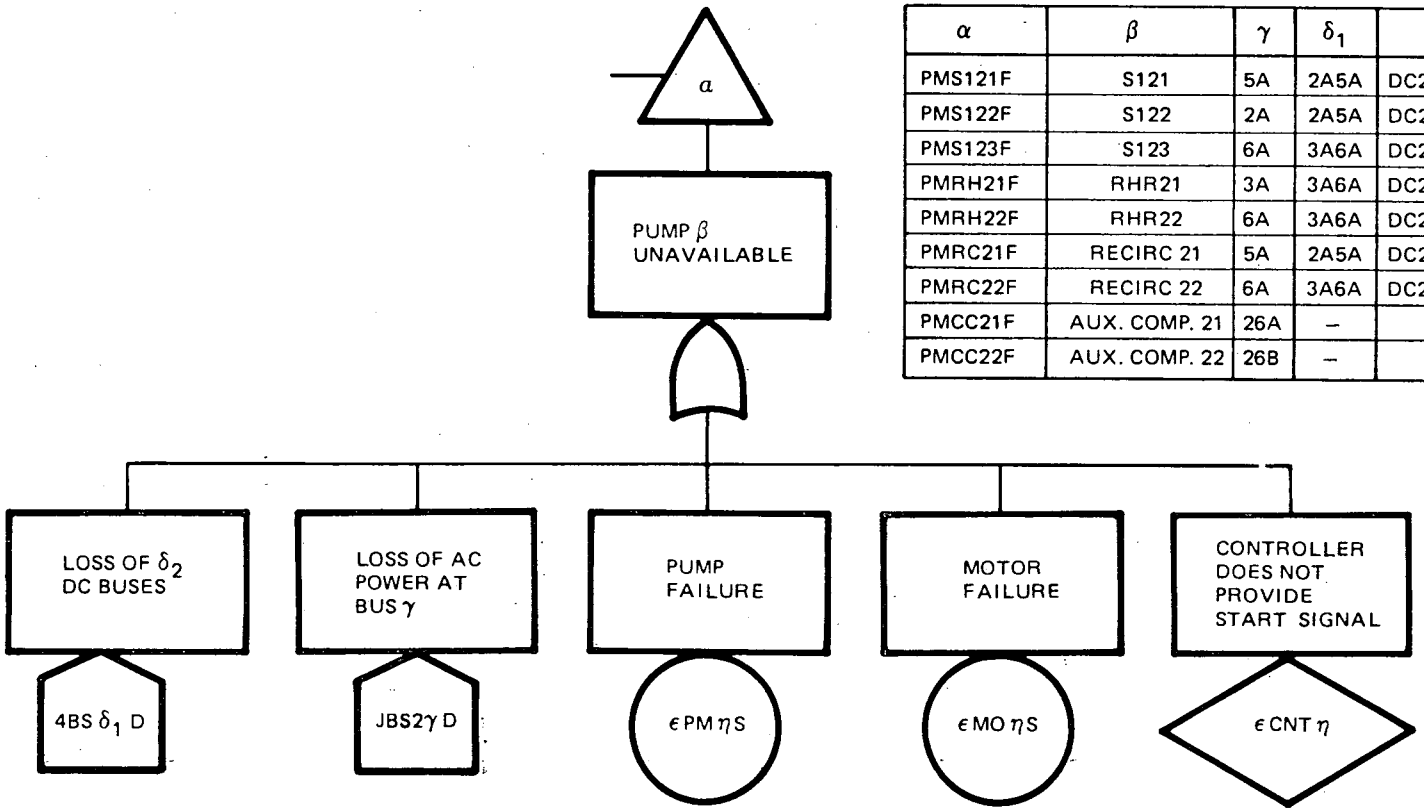
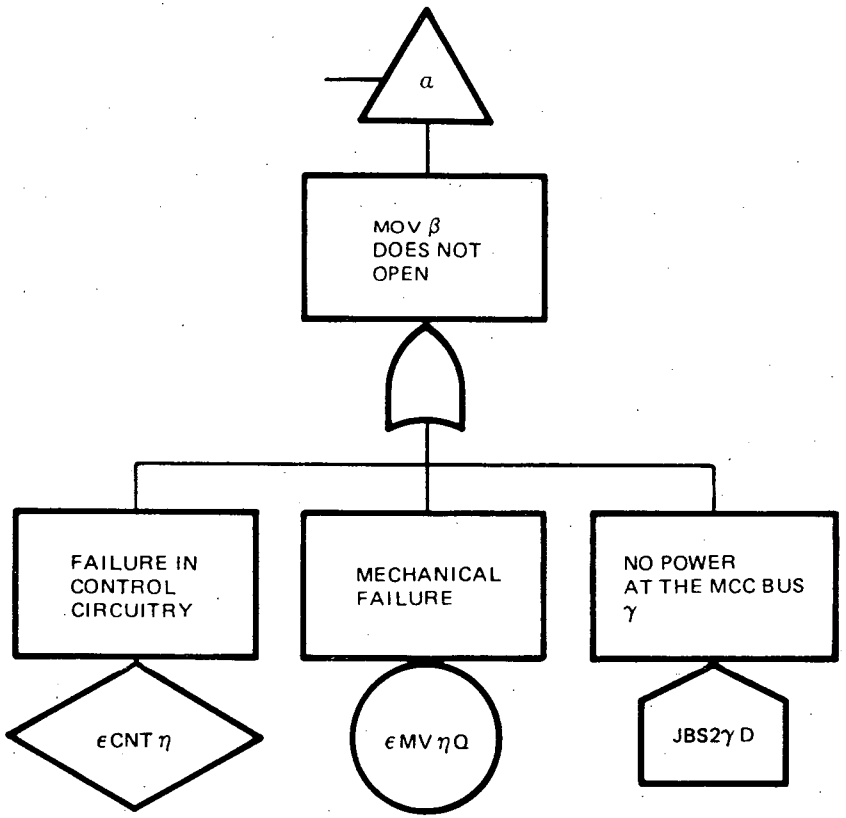


Figure 1.5.2.3.4-17. Indian Point 2 Fault Tree for Blockage of Crosstie Between the Two Heat Exchanger Discharge Lines



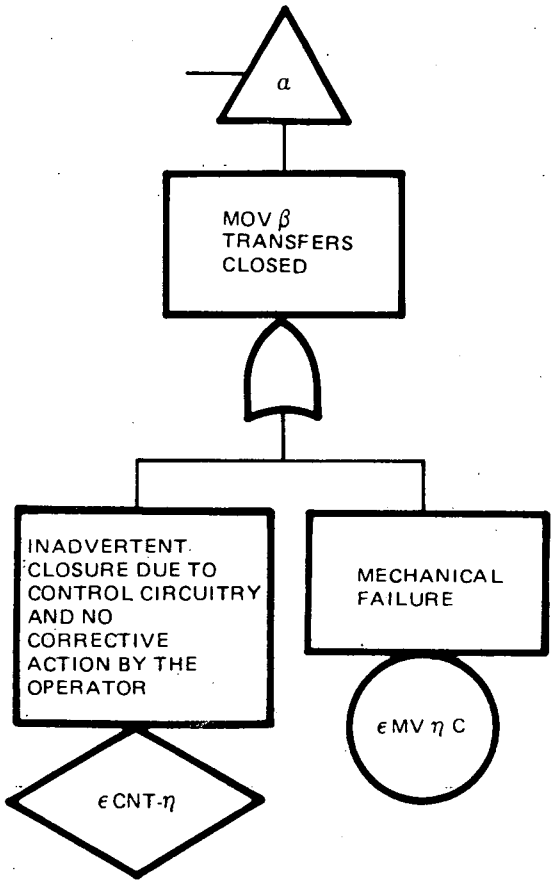
α	β	γ	δ_1	δ_2	ϵ	η
PMS121F	S121	5A	2A5A	DC21/DC23	H	S121
PMS122F	S122	2A	2A5A	DC22/DC24	H	S122
PMS123F	S123	6A	3A6A	DC22/DC24	H	S123
PMRH21F	RHR21	3A	3A6A	DC21/DC23	E	RH21
PMRH22F	RHR22	6A	3A6A	DC22/DC24	E	RH22
PMRC21F	RECIRC 21	5A	2A5A	DC21/DC23	E	RC21
PMRC22F	RECIRC 22	6A	3A6A	DC22/DC24	E	RC22
PMCC21F	AUX. COMP. 21	26A	–	–	U	CC21
PMCC22F	AUX. COMP. 22	26B	–	–	U	CC22

Figure 1.5.2.3.4-18. Indian Point 2 Pump Failure



α	β	γ	ϵ	η
MV888ADO	888A	26A	H	888A
MV888BDO	888B	26B	H	888B
MV889ADO	889A	26A	C	889A
MV889BDO	889B	26B	C	889B
MV822ADO	822A	26A	U	822A
MV822BDO	822B	26B	U	822B
MV885ADO	885A	26A	E	885A
MV885BDO	885B	26B	E	885B
MV746DO	746	26A	E	-746
MV747DO	747	26B	E	-747
MV856BDO	856B	26B	H	856B
MV856FDO	856F	26A	H	856F
MV802ADO	1802A	26A	E	802A
MV802BDO	1802B	26B	E	802B
MV744DO	744	26A	E	-744

Figure 1.5.2.3.4-19. Indian Point 2 MOV Failure to Open



a	β	ϵ	η
MV745ATC	745A	E	745A
MV745BTC	745B	E	745B
MV744TC	744	E	744–
MV1805TC	1805	E	1805
MV638TC	638	E	–638
MV640TC	640	E	–640

Figure 1.5.2.3.4-20. Indian Point 2 MOV Transfers Closed

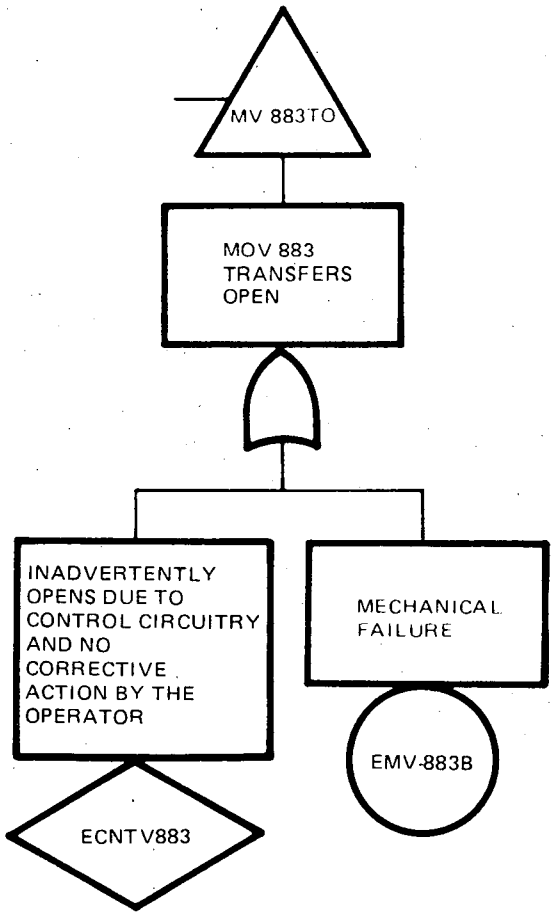


Figure 1.5.2.3.4-21. Indian Point 2
MOV Transfers Open

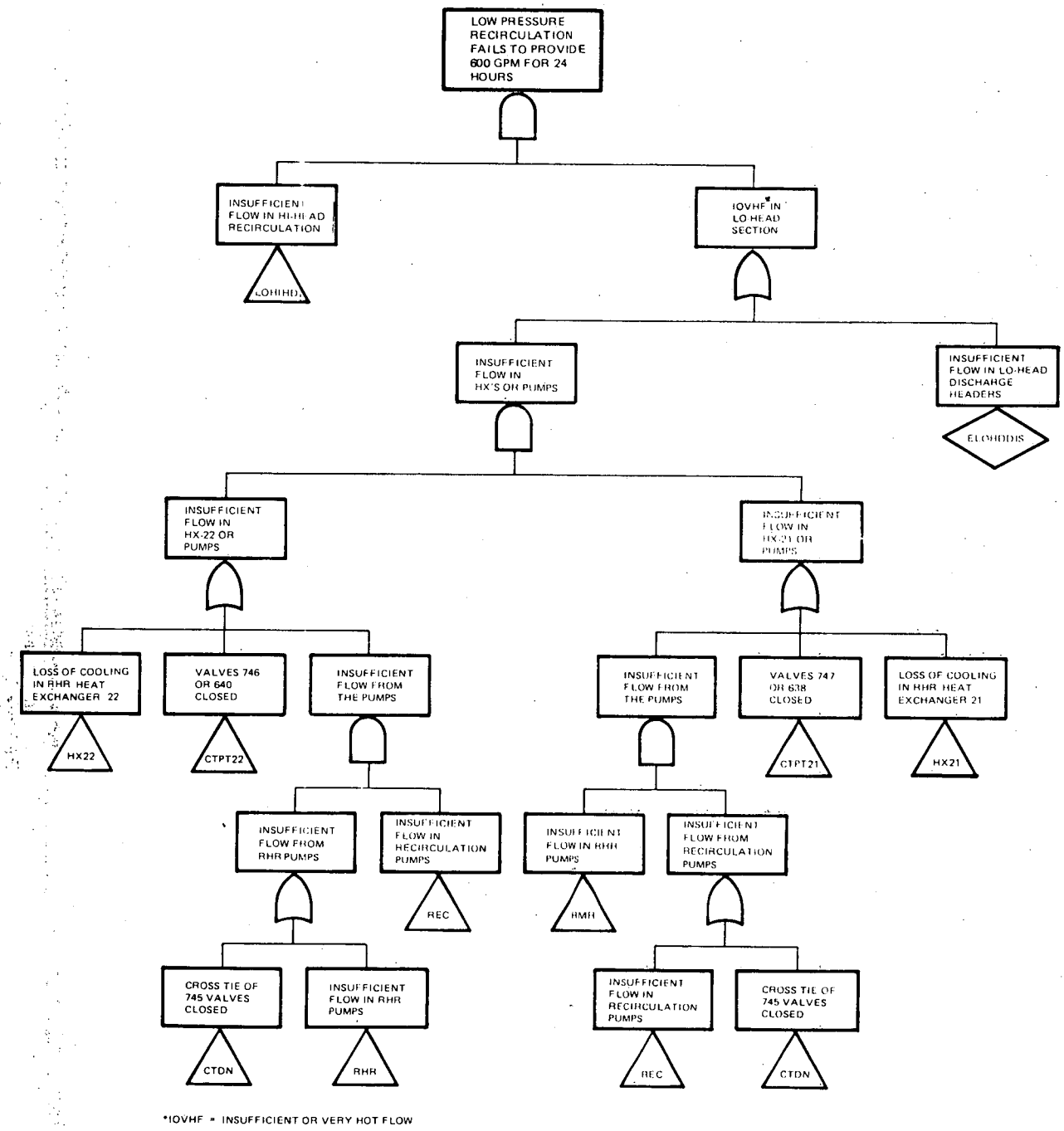


Figure 1.5.2.3.4-22. Indian Point 2 Top Structure of Fault Tree for Low Head Recirculation

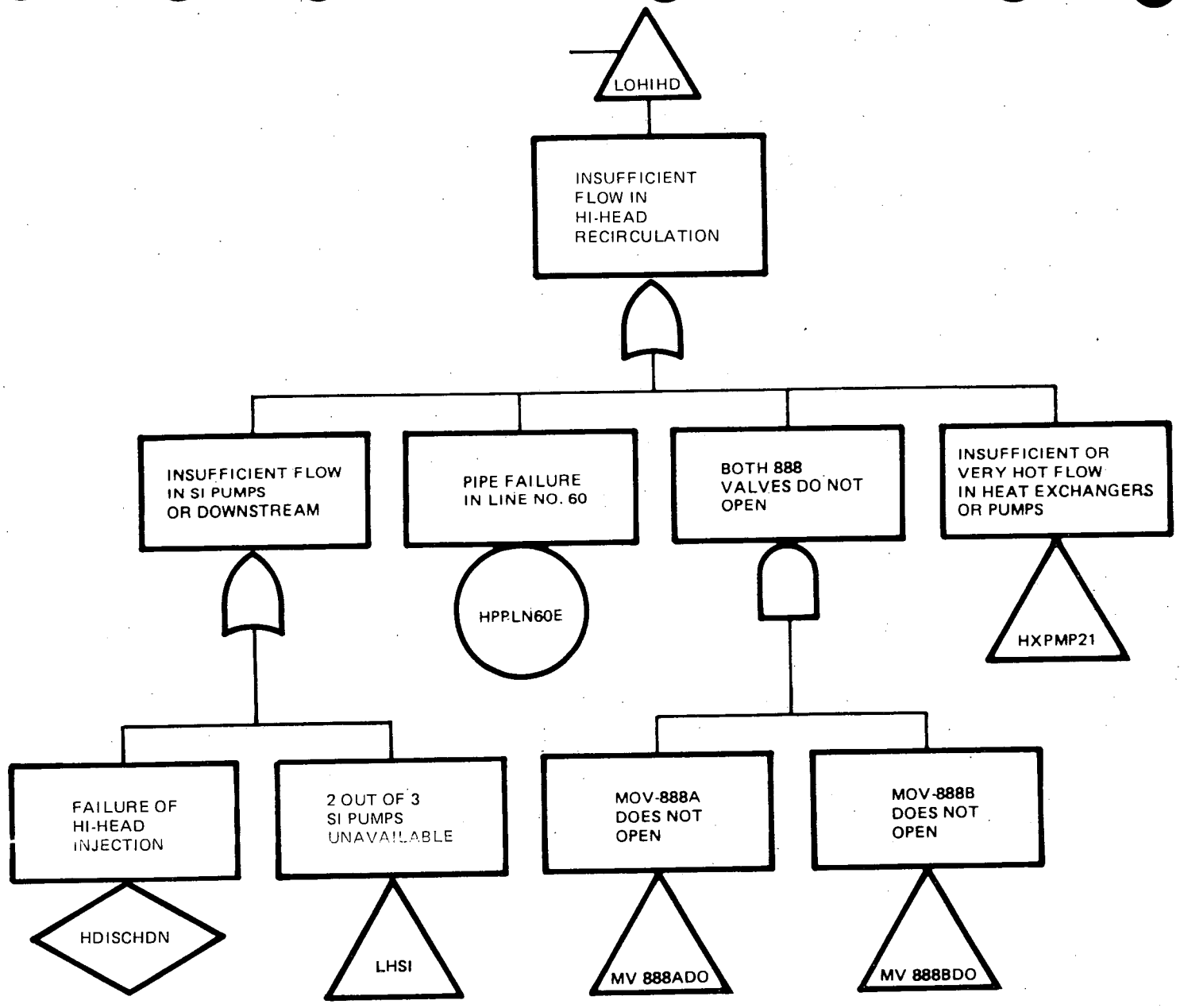


Figure 1.5.2.3.4-23. Indian Point 2 Fault Tree for Failures in High Head Part of the System (from Line 60 to SI Pump Discharge Headers)

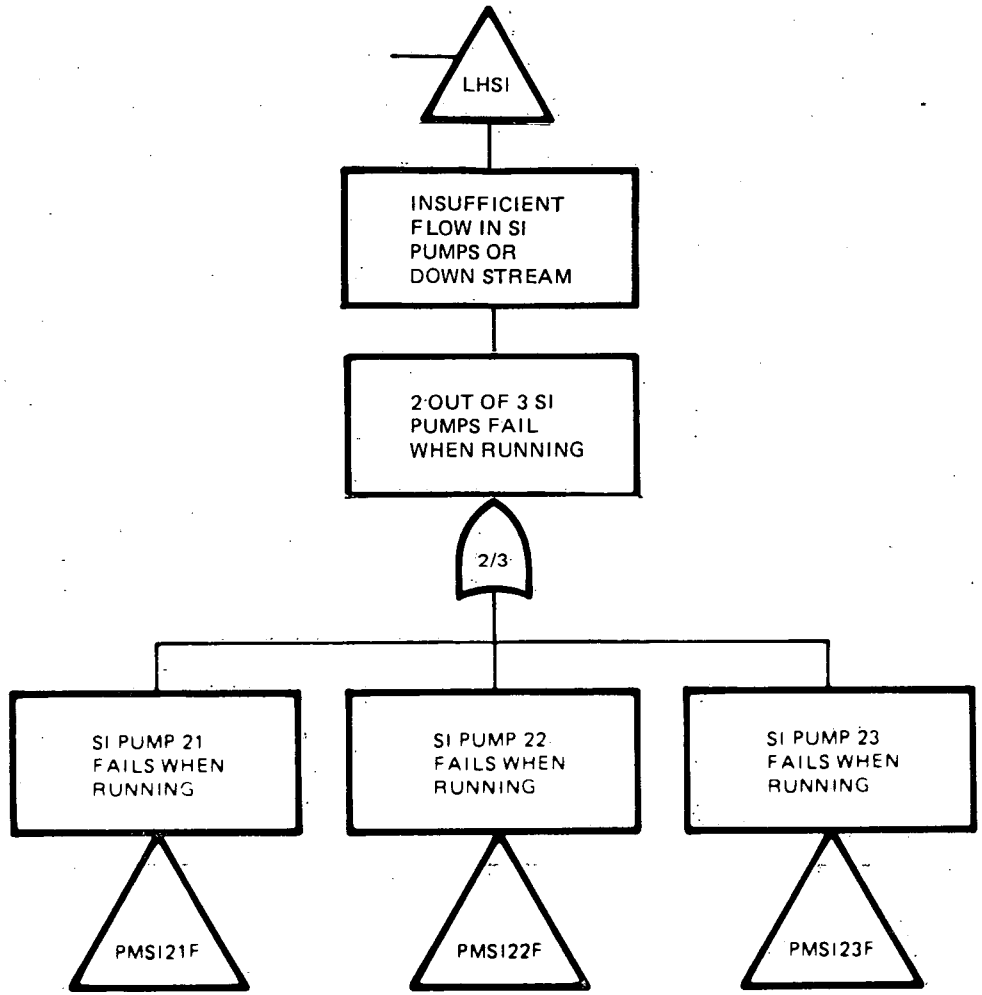


Figure 1.5.2.3.4-24. Indian Point 2 Fault Tree for the Failure of Two Out of Three SI Pumps

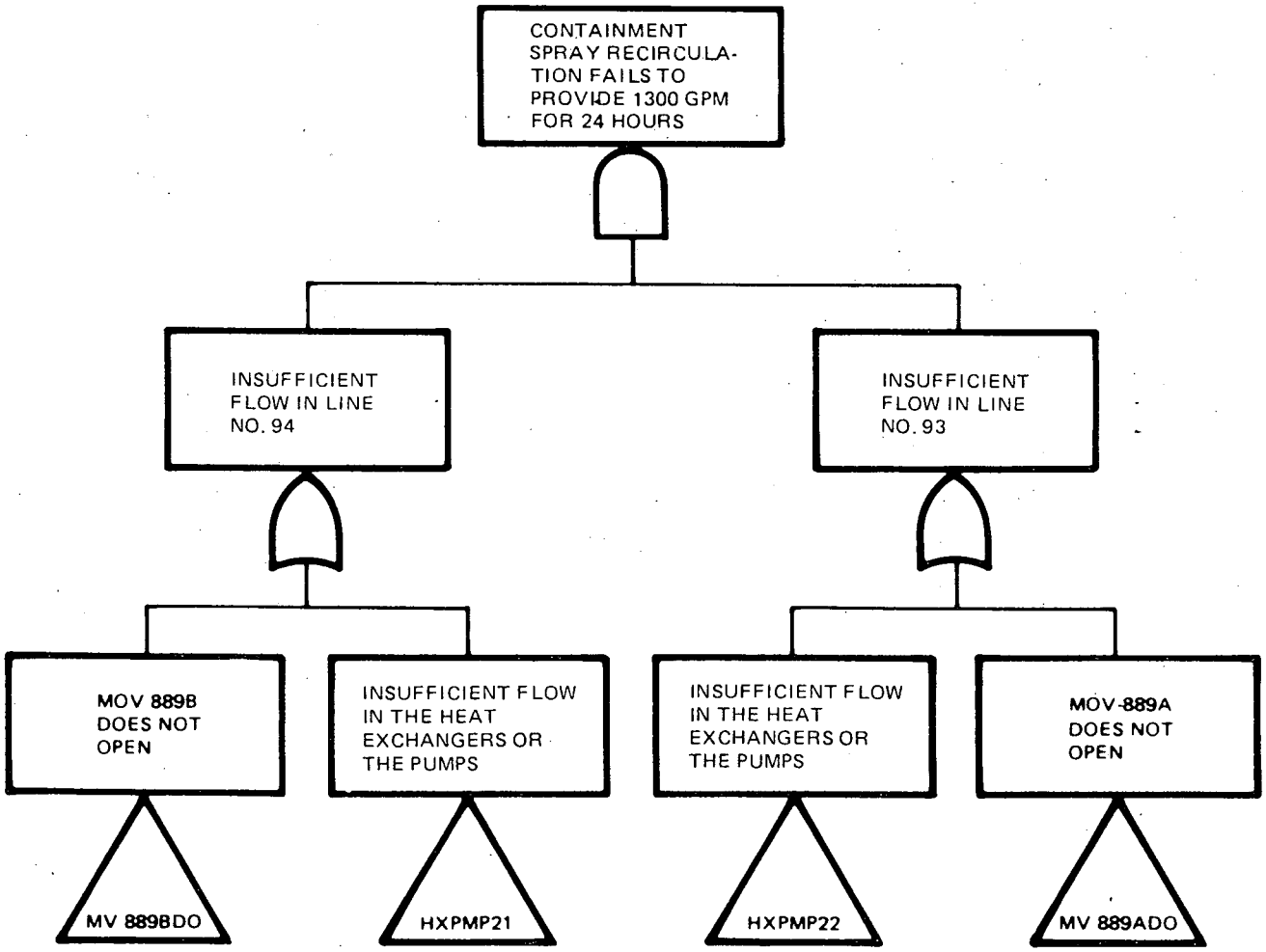


Figure 1.5.2.3.4-25. Indian Point 2 Top Structure of the Fault Tree for Containment Spray Recirculation

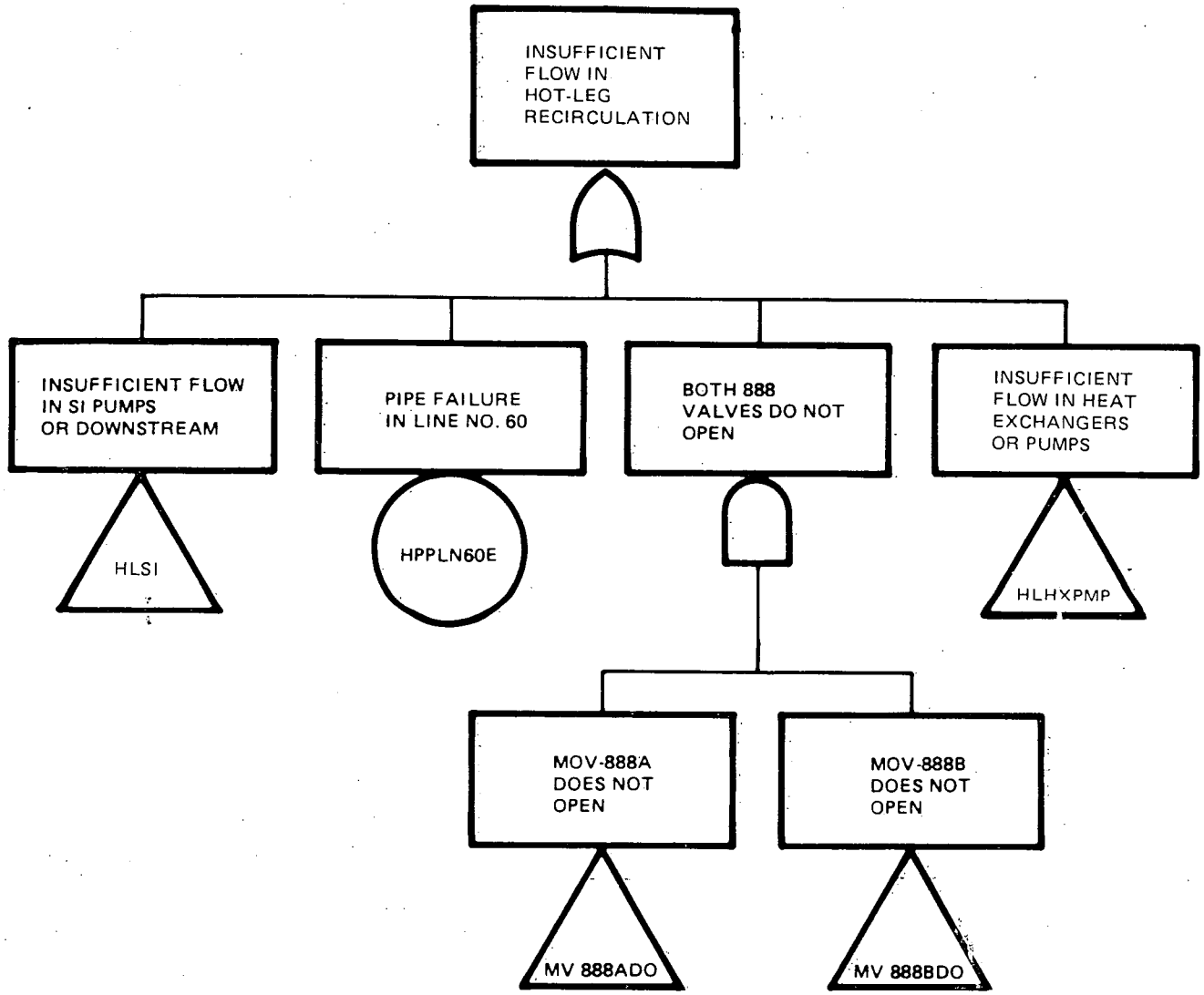


Figure 1.5.2.3.4-26. Indian Point 2 Top Structure of the Fault Tree for Hot Leg Recirculation

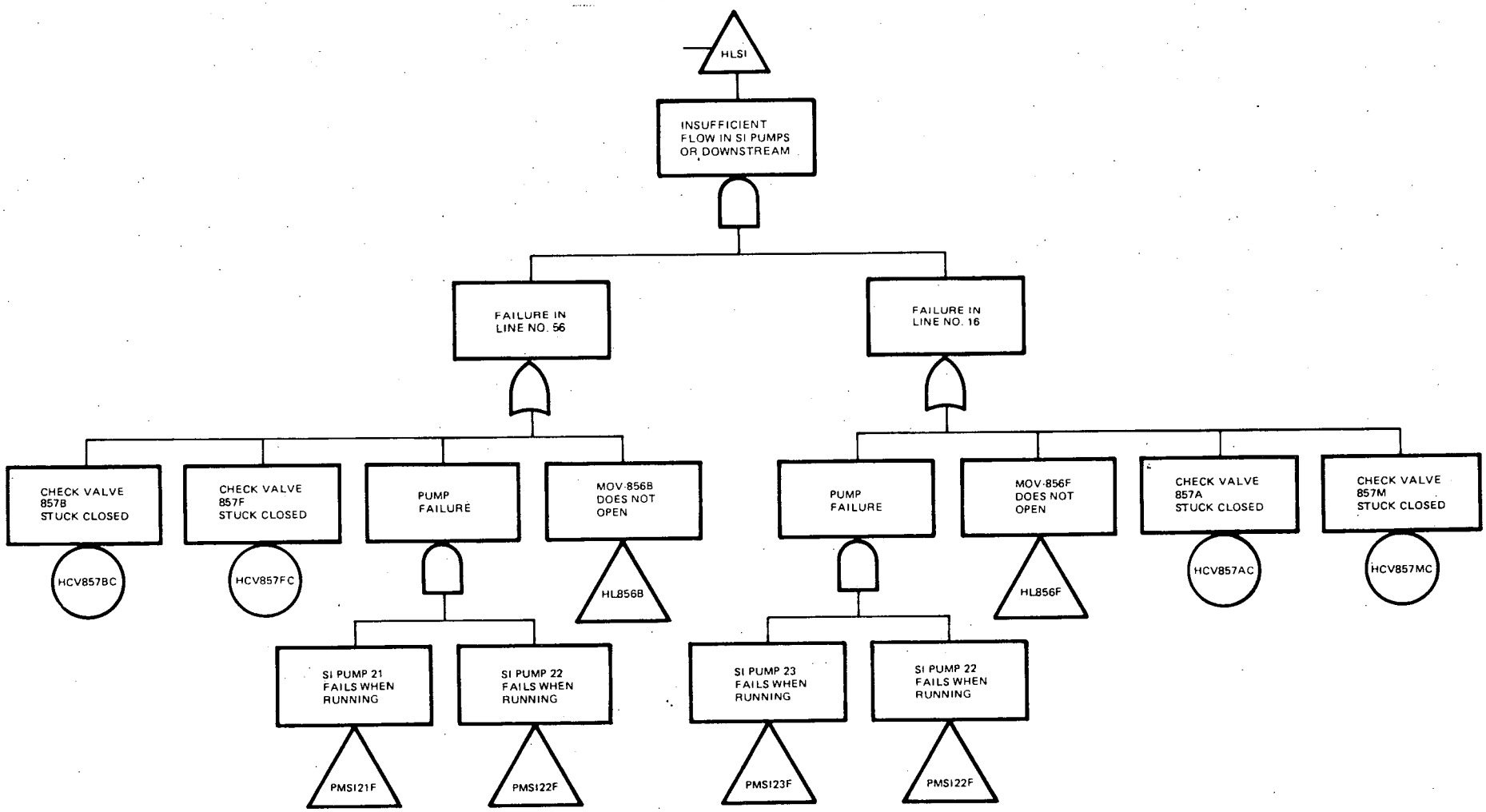


Figure 1.5.2.3.4-27. Indian Point 2 Fault Tree for Failures in SI Pumps on Downstream

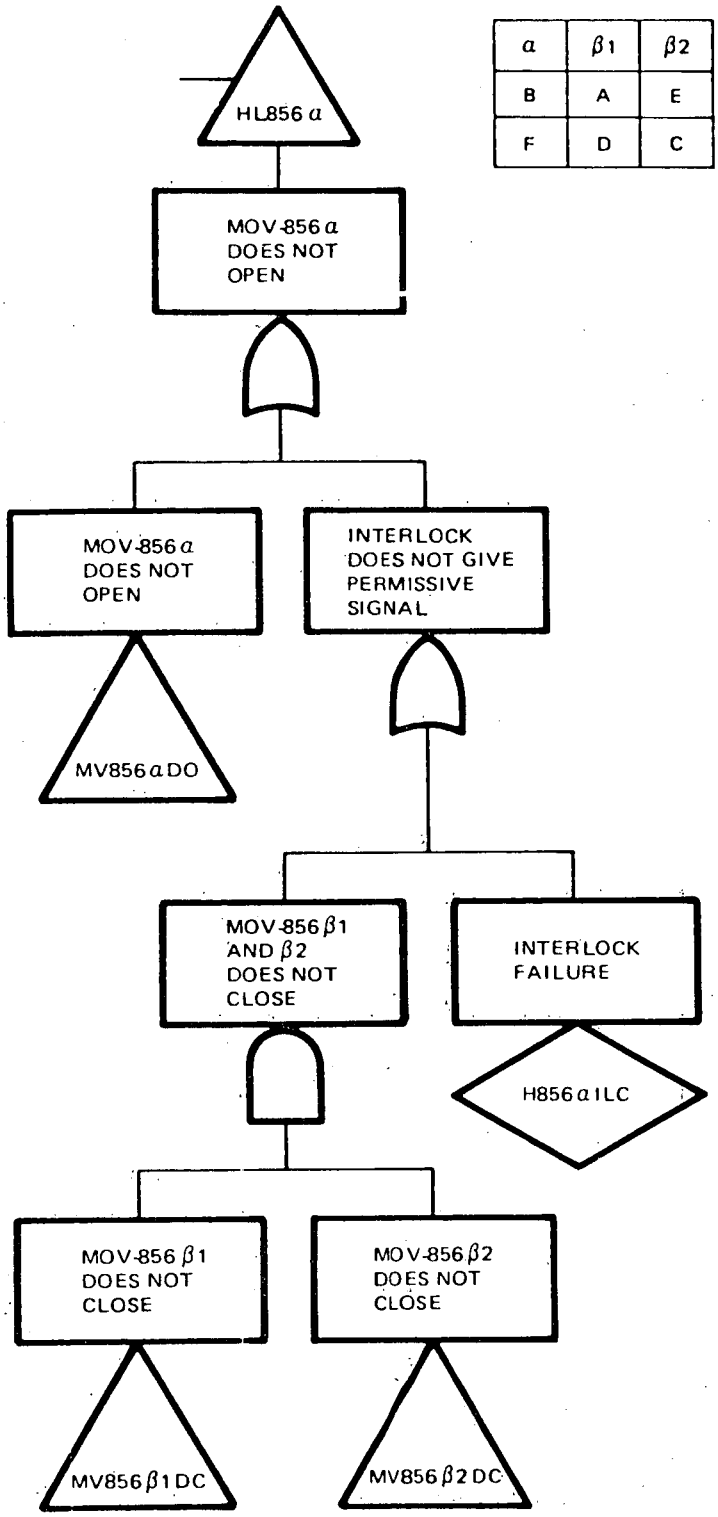


Figure 1.5.2.3.4-28. Indian Point 2 Fault Tree for Hot Leg Isolation MOVs Fail to Open

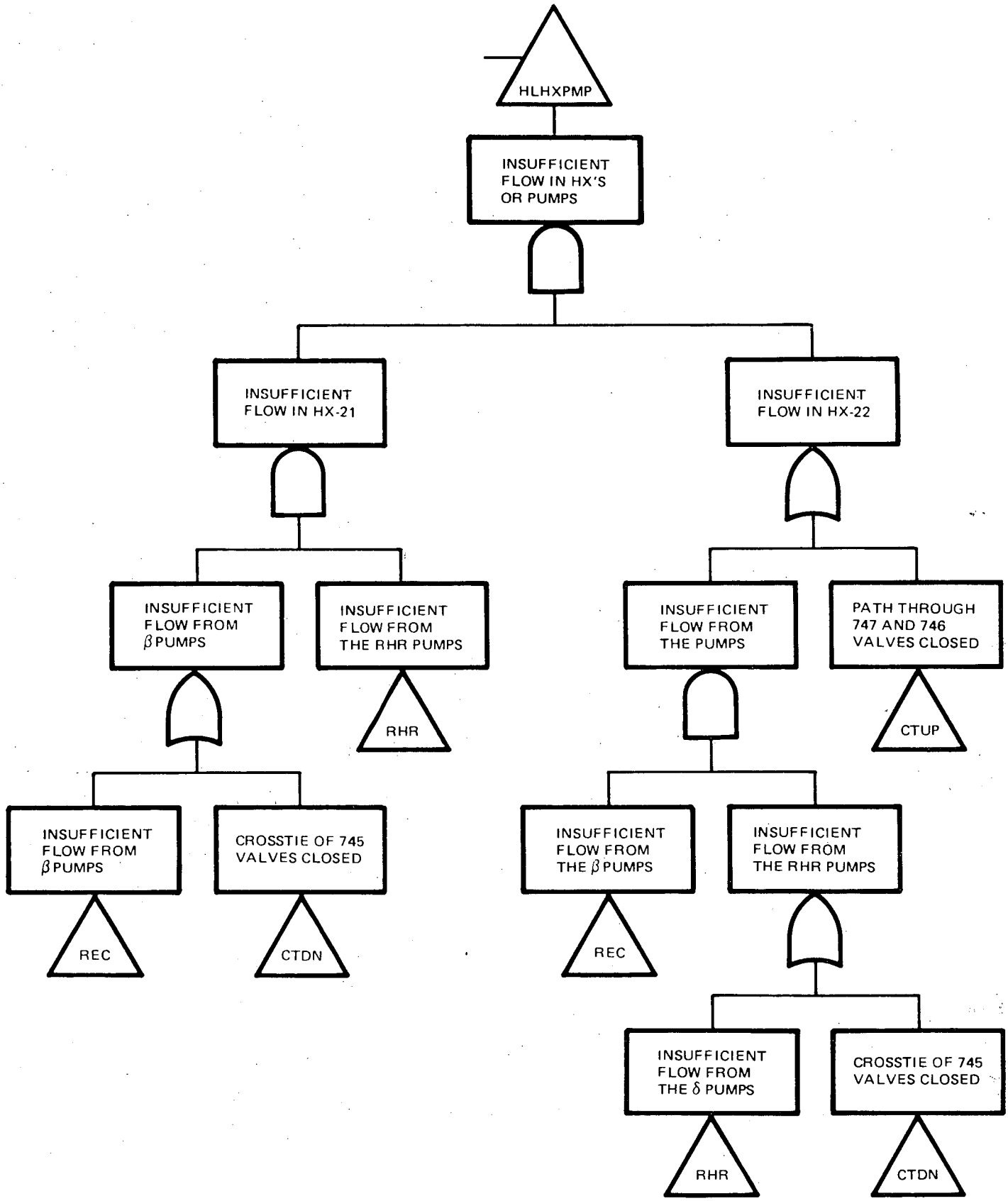
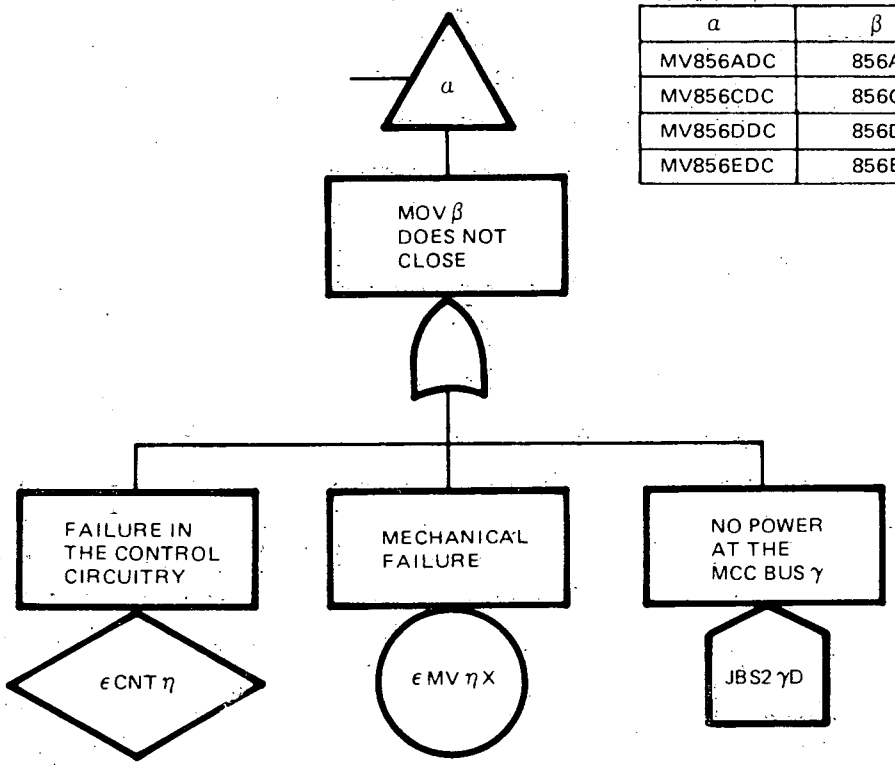


Figure 1.5.2.3.4-29. Indian Point 2 Fault Tree for Insufficient Flow from Both Heat Exchangers to SI Pumps



α	β	γ	ε	η
MV856ADC	856A	26A	H	856A
MV856CDC	856C	26A	H	856C
MV856DDC	856D	26B	H	856D
MV856EDC	856E	26B	H	856E

Figure 1.5.2.3.4-30. Indian Point 2 MOV Fails to Open

1.5.2.3.5 Indian Point Unit 2 Containment Spray System

1.5.2.3.5.1 Summary.

1.5.2.3.5.1.1 Introduction. The containment spray system is evaluated for the post-loss of coolant accident (LOCA) injection phase, during which borated water from the refueling water storage tank (RWST) is pumped to the containment spray headers by the containment spray pumps. During the recirculation phase, spray is provided by the recirculation pumps or the residual heat removal (RHR) pumps.

This analysis has been performed to determine the frequency with which failure of the containment spray and sodium hydroxide (NaOH) addition systems would be expected when they are required to respond following a LOCA. These frequencies will be used in the event trees.

Sodium hydroxide addition is treated as a separate system since it would only be useful in case of a primary coolant release to containment. It appears as a separate event in the event trees.

The analysis of the containment spray system is carried out under the following conditions:

- RWST is available.
- The safeguards actuation signal is present.

The NaOH addition system also requires success of the containment spray system as a previous event in the event trees.

1.5.2.3.5.1.2 Results. Table 1.5.2.3.5-1 summarizes the results for the cases of electric power availability considered (buses 5A and 6A) and lists the Reactor Safety Study (RSS) results as a comparison.

The analysis has revealed the following dominant contributors:

	Mean
• Containment Spray	
- Electric Power to Buses 5A and 6A	7.5×10^{-5}
• Random failures	5.1×10^{-5} (68%)
• Human error	1.4×10^{-5} (18%)
• Maintenance	1.1×10^{-5} (14%)
- No Electric Power to One Bus (5A or 6A)	1.0×10^{-2}
• Random failures	8.9×10^{-3} (89%)
• Maintenance	8.1×10^{-4} (8%)
• NaOH Addition System	
- Electric Power to Buses 5A and 6A	9.6×10^{-4}
• Random failures	7.6×10^{-4} (79%)
• Human error	2.0×10^{-4} (21%)

	Mean
- No Electric Power to One Bus (5A or 6A)	1.3×10^{-3}
• Random failures	1.1×10^{-3} (85%)
• Human error	2.0×10^{-4} (15%)

1.5.2.3.5.1.3 Conclusion. Both systems have single failure points, but these are generally associated with passive components; i.e., the containment spray suction header and the spray additive tank in the NaOH system. The tank outlet valve in the NaOH system is also a single failure point but is normally locked in the open position. Failures of this valve are caused by structural or human errors and have been considered in the analysis.

In the containment spray system, random hardware failures due to the spray pumps are the dominant contributors to system unavailability. The loss of one bus increases the unavailability.

In the NaOH addition system, failure of the spray additive tank and the outlet valve dominate the random failures. Human errors associated with those manual valves which are required to change position during each monthly test also contribute significantly to system unavailability.

Probability distributions of containment spray and NaOH system unavailability for the electric power states considered are shown in Figures 1.5.2.3.5-1 and 1.5.2.3.5-2.

1.5.2.3.5.2 System Description.

1.5.2.3.5.2.1 System Functions. The primary functions of this system are:

- To reduce the containment pressure following a LOCA or a steam break accident inside containment.
- To remove iodine, by NaOH addition, released to the containment atmosphere in the event of a breach in the fuel cladding following a LOCA.

A secondary function is to provide fire dousing water to the charcoal filter banks of the containment recirculation fan unit (this function is analyzed in a separate section on containment cooling and filtration).

1.5.2.3.5.2.2 System Success Criteria.

1.5.2.3.5.2.2.1 Containment spray. During the injection phase, either of the two spray trains delivering borated water at 2,500 gpm through its set of 221 spray nozzles is sufficient to maintain and reduce containment pressure to assure containment integrity following a LOCA.

Success paths for containment spray during the injection phase are illustrated in the simplified block diagram, Figure 1.5.2.3.5-3. This diagram shows that the borated water supply from the RWST and failure of the suction header line 181 are the only two single failure points in the system. The two pump trains in parallel illustrate that either one is sufficient for system success. The two parallel motor-operated valves (MOVs) in each spray train provide added assurance that the flow circuits can be opened when needed. Otherwise, all valves are normally in their correct position for system operation.

1.5.2.3.5.2.2.2 NaOH addition. During the injection phase and continuing for 30 minutes into the recirculation phase, at least one of the NaOH addition trains must introduce approximately 25 gpm of the NaOH solution from the spray additive tank into an operating containment spray train.

This success criterion is illustrated by the simplified block diagram, Figure 1.5.2.3.5-4. Only valves that must change position are shown.

There are three single failure points: (1) supply of the NaOH solution from the spray additive tank, (2) valve 1841 which must remain open (normally locked open), and (3) valve 873B not remaining closed (normally locked closed).

1.5.2.3.5.2.3 System Configuration. The containment spray and NaOH addition systems are illustrated by the flow diagram, Figure 1.5.2.3.5-5.

1.5.2.3.5.2.3.1 General description. For the injection phase, the containment spray system consists of the following primary components:

- Containment Spray Pumps 21 and 22
- Motor-Operated Discharge Valves 866A through D
- Discharge Header Containment Isolation Valves 869A and 869B
- Pump Suction Valves 865A and 865B
- Discharge Check Valves 867A and 867B
- Two Sets of Spray Nozzles (221 each set)
- Suction Header Line 181
- Discharge Lines

The following associated valves and lines are necessary for system tests:

- Spray Test Line 164 and RWST Overflow Line 161
- Spray Test Valves 878A and 878B
- Air Test Valves 868A and 868B

The NaOH addition portion of the system for iodine removal operates during the injection phase and for approximately 30 minutes into the recirculation phase (LOCA only). This part of the system consists of the following primary components.

- Spray Additive Tank
- Air-Operated Tank Valves, 876A and 876B
- Manual Valves, 1839A and 1839B
- Manual Tank Isolation Valve 1841
- Check Valves, 1838A and 1838B
- Eductors 21 and 22
- Lines 188, 579, 187, 578
- Nitrogen Supply Valve 872B

Manual Valve 873B (from suction header 181) is used for periodic flushing of the eductors with borated water from the RWST.

Sample and instrumentation lines and valves less than 3 inches in diameter are noted in Figure 1.5.2.3.5-5 but are not included in the analysis because their failure will not affect system operation.

Lines and valves shown in Figure 1.5.2.3.5-5 for charcoal filter dousing are discussed in the section on containment fan coolers and filtration.

The RWST is evaluated as a separate interfacing system because it serves several systems.

The spray pumps, valves, and spray additive tank are located in the primary auxiliary building. Spray nozzles and their headers are located inside the containment building.

1.5.2.3.5.2.3.1.1 Major system components. The major components of the system are described in the following paragraphs.

1.5.2.3.5.2.3.1.2 Containment spray pumps. The spray pumps are of the horizontal, single stage, centrifugal type driven by electric motors and are each capable of delivering 2,500 gpm at 300 psig. The pumps are not fitted with flow or pressure instrumentation. The pumps have mechanical seals which do not require external cooling.

Each pump has the heat removal capability necessary to maintain and reduce containment pressure sufficient to assure containment integrity following a LOCA.

The two containment spray pumps are supplied with 480V power from individual breakers as follows:

- Pump 21 Bus 5A
- Pump 22 Bus 6A

Each pump breaker control circuit is identical; therefore, only the circuit of pump 21 will be discussed. Each breaker's control switch is located on the safeguards panel; status light indications are above each switch. There are two switches; one for pump 21 to control breaker 52/CS1 and one for pump 22 to control breaker 52/CS2. The switch has the following four positions (spring-return-to-auto):

- Pull-Out. The pump is disabled from starting by any automatic start signal. With the switch in this position the "Safeguards Equipment Locked Open" alarm will be annunciated on the safeguards panel in the central control room (CCR).

- Stop. Pump will be stopped if it is running by energizing the trip coil.

- Auto. Pump will be started by the containment spray initiation signal.

- Start. Pump will be started.

When the pump is running it can be tripped by:

- Putting the switch to either the "Stop" or "Pull-Out" position.
- Undervoltage at the 480V bus 5A.
- Closing of the recirculation phase switch RS-1 (pump 22 only).
- The magnetic overload breaker, from overcurrent.

1.5.2.3.5.2.3.1.3 Motor-operated pump discharge valves. There are two parallel 8-inch motor-operated discharge valves in each of the two flow trains. These are MOVs 866A and B, and MOVs 866C and D in lines 51 and 15, respectively (see Figure 1.5.2.3.5-5). These are the only valves which are required to change position for the system to operate. Only one out of two in each train need open for both trains to operate successfully. Valves A and C are powered from MCC-26A and valves B and D from MCC-26B.

1.5.2.3.5.2.3.1.4 Air-operated NaOH addition valves. The two air-operated valves in the discharge line from the spray additive tank are normally closed. These are in parallel so that if either one opens the NaOH solution can be obtained. These valves fail open upon loss of air. Air is provided from the instrument air system.

1.5.2.3.5.2.3.1.5 Spray additive tank. The spray additive tank is made of carbon steel and is lined with stainless steel to protect the tank from the highly corrosive caustic contained within. The tank contains at least a 30% concentration of NaOH. The NaOH is effective in removing elemental (inorganic) iodine by a trapping process that fixes iodine into a liquid phase. By removing the iodine from the containment atmosphere, the offsite thyroid dose is reduced. The NaOH will also increase the pH of the fluid in the sumps.

The level in the tank is monitored at the safeguards panel in the CCR by level transmitter (LT) 931. This device signals level controller (LC) 931 to activate a low level alarm ("NaOH Tank Low-Level") at 80% level. The alarm is also on the safeguards panel. The tank level is also locally monitored by level indicator (LI) 932. Technical specifications require that the tank contain at least 4,000 gallons of a 30% NaOH solution. This corresponds to a level of 72% of full scale. The level in the additive tank will be maintained above 80% (4,400 gal.) to preclude actuation of the low level alarm during normal plant operations.

Flow from the tank is measured by flow transmitter (FT) 930 which signals flow indicator (FI) 930 mounted on the safeguards panel. When flow is established with both pumps, FI-930 flow is about 50 gpm. The tank is protected from overpressure by relief valve 1815 which is set at 275 psig with a capacity of 20 gpm. Valve 873A is provided for tank draining should repairs be necessary (not shown in Figure 1.5.2.3.5-5).

To prevent decomposition of the NaOH it is essential to maintain an inert atmosphere in the tank during long term storage. Therefore, a nitrogen supply is provided to the tank through manual valve 872B and line 578. A pressure on the order of one-half to 2 psig will be maintained in the tank during storage. The pressure is monitored locally on pressure indicator (PI) 930 and relieved when necessary through manual valve 871. This may be required during seasonal temperature changes. Two vacuum breakers are installed on the tank to admit air when NaOH is drawn from the tank.

1.5.2.3.5.2.3.1.6 Spray nozzles. The stainless steel spray nozzles are of the ramp bottom design and are not subject to clogging by particles less than 3/8 inch in maximum dimension. The nozzles provide droplets of 1,000 micron diameter when a differential pressure of 40 psig exists across the nozzle. They are located in the containment building and are connected to four 360° ring headers of radii 8 feet, 2 inches (228.5-feet elevation); 25 feet, 4 inches (223.5-feet elevation); 42 feet, 3 inches (218.5-feet elevation); and 59 feet, 6 inches (213.5-feet elevation). Two sets of 221 nozzles each (442 nozzles) are distributed on the four headers. This nozzle and header arrangement results in maximum coverage with either branch of the system operating alone.

1.5.2.3.5.2.3.1.7 Liquid jet eductors. A liquid jet eductor provides the means of adding NaOH to the spray water. This device uses the kinetic energy of a pressurized liquid to entrain another liquid, mix the two, and discharge the mixture against a counter pressure. The pressurized liquid is the spray pump discharge which is used to entrain the NaOH solution and discharge the mixture into the suction of the spray pumps. There is one eductor for each spray pump. They are located in the primary auxiliary building.

1.5.2.3.5.2.4 System Operation.

1.5.2.3.5.2.4.1 Normal system arrangement. By nature, the system is inactive and as such does not interfere with normal plant operation. The pumps are idle and are open to the RWST by locked open suction valves 865A and 865B. The pumps' motor-operated discharge valves 866A, 866B, 866C, and 866D are closed. The discharge header containment isolation valves (869A and 869B) are locked open. The spray additive tank is filled and is isolated by closed air operated valves 876A and 876B. All instrument valves are opened. Drain and test connection valves are closed and the pipe ends are capped. The spray additive tank N_2 supply valve and vent valve are closed. In-line tank discharge valve 1841 is locked opened and eductor valves 1839A and 1839B are locked open. Test valves 878A and 878B, 1806A and 1806B are locked closed. Test valve 1813 is closed. Air test valves 868A and 868B are locked closed and their ends capped.

1.5.2.3.5.2.4.2 System actuation. Following a safety injection signal the containment spray system is brought into service by either of the following signals:

- High-High Containment Pressure. This signal occurs at a value equal to approximately 50% of the containment design pressure (maximum setpoint is 30 psig).

- Manual Initiation. Two buttons, one for each spray pump train, on the safeguards panel.

If a spray signal is initiated by high-high containment pressure, the following will occur:

- The spray pump discharge valves 866A through 866D are supplied with an open signal.

- Both spray pumps will be signaled to start.

- Additive tank discharge valves 876A and 876B will be supplied with an open signal 2 minutes after the spray signal is initiated provided that the NaOH cancel button has not been pressed.

For each manual pushbutton depressed, a single pump train will start.

1.5.2.3.5.2.4.3 Automatic system response. When the spray system is activated, both spray pumps will draw water from the RWST through line 181. The pumps discharge to the spray headers via lines 15 and 51. These lines each contain parallel valves (866A/B and 866C/D). The parallel flow paths assure flow in the event a valve should fail to open on demand. These valves are provided with control switches on the safeguards panel and are normally closed. Position indicating lights are provided for each valve on the safeguards panel.

Unless canceled by the operator, a portion of the pump discharge is directed through the liquid jet eductor which draws the NaOH solution from the spray additive tank and injects the fluid into the spray flow.

A 2-minute time delay is utilized so that the operator can determine the type of coolant leak that has occurred, and if necessary, cancel the addition of NaOH (see Section 1.5.2.3.5.2.4.4, Manual Operator Action).

It would take approximately 70 to 80 minutes to discharge the total NaOH solution in the spray additive tank using both pumps. For the first 15 to 22 minutes following the maximum LOCA, both spray pumps may be operating. After the injection phase has been completed, one spray pump will continue to operate for approximately 30 minutes (or until the RWST is empty) to complete the addition of NaOH. FI-930 will indicate flow from the additive tank. Containment pressure indicators (PI) 948A, 948B, 948C, and 949A, 949B, and 949C, are located in the CCR on the safeguards panel. The system will be taken out of service after recirculation flow has been established by the eight-switch sequence (see the safety injection system) and the RWST no longer contains enough coolant to continue running spray pump 21 (or 22 if 21 is inoperative).

1.5.2.3.5.2.4.4 Manual operator action. If the operator determines that the accident is a steam break, he has 2 minutes to press the "NaOH Cancel" button on the safeguards panel. This will prevent valves 876A and 876B from opening and, thus, the addition of NaOH will be prevented. The "NaOH Cancel" button is provided to reduce the chances of accidental NaOH injection and also to avoid NaOH injection when the type of accident will not result in fission product release to the containment atmosphere. This "Cancel" decision may be defeated at any later time by opening both valves by using their control switches on the safeguards panel. Each valve is provided with a control switch and position indicating lights on the safeguards panel.

1.5.2.3.5.2.4.5 Charcoal filter dousing. The 10 motor-operated spray valves, 880A through 880K (no "I" valve), are normally closed and when opened each will annunciate the "Safeguards Valves Off Normal Position" alarm. Each valve has a control switch and indicator lights located on the safety injection supervisory panel (for further details see Section 1.5.2.3.5.2.3, Containment Fan Cooling).

1.5.2.3.5.2.5 Alarms. Alarms are generated to warn the operator that an unsatisfactory condition exists and that appropriate corrective action is required. Only those alarms directly concerned with the

containment spray system are discussed. All the following alarms are annunciated on the two safeguards panels:

- Safeguards Valve Off Normal Position. This is a common alarm, generated when any engineered safeguards system valve leaves the position called for during normal plant operations. Only valves directly used in the spray system are listed.

Valve Number	Normal Position	Alarms When	Valve Name
880A through 880K	Closed	Valve leaves full closed	Charcoal filter dousing units
889A and 889B	Closed	Valve leaves full closed	Outlet of RHR heat exchangers to inlet of spray headers
1813	Closed	When open	Spray test line to RWST

- Spray Additive Tank Low-Level. This alarm is generated when the level in the additive tank decreases to 80%.

- Safeguards Equipment Locked Open. This is a common alarm, generated when the control switch for either of the spray pumps is placed in the pull-out position.

- High-High Containment Pressure. This is a common alarm, actuated when one out of six pressure detectors indicates 30 psig within containment.

- 480V Switchgear Motor Trip. Common alarm, annunciated when either pump trips due to overload.

1.5.2.3.5.2.6 Interfaces With Other Systems. Following a LOCA the containment spray system including NaOH addition depends on the following systems:*

- Refueling Water Storage Tank. Stores and provides borated water for the functions of the system.

- Electrical Power. Pump and valve operation (see Table 1.5.2.3.5-2 for list of buses and motor control centers).

*This system is redundant to the containment fan coolers for containment heat removal and pressure reduction and radioactive iodine removal. When necessary, the containment spray system provides fire dousing water for the fan cooler charcoal filters.

- Safeguards Actuation System. This is for the system start initiating signals.

1.5.2.3.5.2.7 System Test and Maintenance. Portions of the system are inspected and tested for proper functioning at regular intervals. At other times, items of equipment are rendered inoperative because of maintenance actions. During testing the system can usually be quickly returned to operational status. During maintenance this may not be so; the times allowed before shutdown is required are specified as operating limits. Both conditions can effect system availability as discussed in the following.

1.5.2.3.5.2.7.1 System/component tests. The containment spray system is a principal plant safeguard that is normally on standby during reactor operation. Complete systems tests cannot be performed when the reactor is operating because a safety injection signal causes reactor trip, main feedwater isolation and containment isolation. For a containment spray system test, the system must be temporarily disabled. Operability is ensured by combined systems tests performed during refueling shutdowns, with more frequent component tests, which can be performed during reactor operation.

The refueling test demonstrates proper automatic operation of the containment spray system. With the pumps blocked from starting, this test verifies that the components receive the safeguards actuation signal in the proper sequence. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.

The pumps are started manually from the control room on a monthly basis. Only one pump is run at a time. That flow path is returned to the valve lineup for containment spray before another is tested.*

Pump run time can be approximately 20 to 30 minutes each. A pump must run for at least 20 minutes for a successful test. Motor-operated valves are stroked monthly from the control room as part of the pump operability tests.

During reactor operation, the instrumentation is generally checked each shift. The initiating circuits are tested monthly. The testing is discussed in the safeguards actuation system description.

The NaOH addition system is partially tested whenever the associated spray pump is tested; i.e., monthly. Because of the corrosiveness of the NaOH, flow from the spray additive tank is not tested. The eductor, however, is tested by opening the locked closed valve 873B to the RWST header. This permits flushing of the eductor, proving that it functions properly. Spray nozzles are checked for blockage every 5 years by means of air or infrared techniques. Concentration of NaOH solution in the spray additive tank is checked monthly. Table 1.5.2.3.5-3 summarizes the test/inspection requirements.

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*At Indian Point Unit 2, should a safeguards actuation signal occur when a pump is running, the pump will be automatically disconnected from the bus in the normal manner and reloaded on the bus according to the automatic load sequencing for that bus.

1.5.2.3.5.2.7.2 Maintenance time limits. According to the unit technical specifications, one containment spray pump may be out of service for a period not to exceed 24 hours, provided the five fan cooler units are operable and the remaining containment spray pump is demonstrated to be operable.

Any valve required for the functioning of the system during and following accident conditions may be inoperable provided it is restored to an operable status within 24 hours and all valves in the system that provide the duplicate function are demonstrated to be operable.

Any maintenance of the spray additive tank requires reactor shutdown.

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1.5.2.3.5.3 System Logic Models.

1.5.2.3.5.3.1 Top Undesired Events. Two different fault tree models have been constructed to evaluate the frequency of:

1. Insufficient borated water sprayed into containment (containment spray during injection).

2. Insufficient NaOH solution injected into containment (NaOH addition).

The two different fault trees correspond to the event tree events of containment spray (CS) and NaOH addition (NA), respectively.

1.5.2.3.5.3.2 System Fault Tree Models. The fault tree for the CS event (Item 1) is shown in Figure 1.5.2.3.5-6. Inhibit gates below the top event OR gate condition subsequent gates depending on test or maintenance states of the system. The tree is also conditional upon success of the following other systems:

- RWST borated water supply (evaluated elsewhere as a separate system).
- Electrical power to supply buses and motor control centers.
- Automatic start signal.

The fault tree for the NaOH additions (NA) event (Item 2) is shown in Figure 1.5.2.3.5-7. The system depends upon a particular spray pump circuit associated with its eductor; therefore, the spray pumps are shown here in addition to Figure 1.5.2.3.5-4 (the failure frequencies for the spray pump circuit are derived from analysis of the CS fault tree analysis).

1.5.2.3.5.3.3 Basic Event Codes. Tables 1.5.2.3.5-4 and 1.5.2.3.5-5 list the basic event codes appearing in the two fault trees. Several "house" events appear in the trees showing dependency on the support systems list above. These have been coded as though they were basic events but are not listed in the tables.

Also shown in the tables are the applicable failure modes and their plant specific failure rates with reference to the list of components (see Tables 1.5.2.3.5-4 and 1.5.2.3.5-5).

1.5.2.3.5.3.4 Minimal Cutsets. Minimal cutsets for both fault trees have been identified using the computer code RAS. These combinations are listed in Tables 1.5.2.3.5-6 and 1.5.2.3.5-7. The dominant cutsets are identified through quantifications in Section 1.5.2.3.5.4. Single failures are identified by these tables and are also illustrated in Figures 1.5.2.3.5-3 and 1.5.2.3.5-4.

1.5.2.3.5.3.4.1 Containment spray. Considering only hardware failures, there is one single event cutset (single failure point) as shown in the fault tree, Figure 1.5.2.3.5-6. This is the passive component, line 181, from the RWST to the two spray pumps.

- CPP0181G. Suction line from the RWST.

The failure mode is plugging of the line--a very low probability event. Rupture of this line would also cause failure of the system; however, because of the large volume of water that would be released it would be immediately detected and the reactor shut down. For this reason, the rupture failure mode was not listed.

There are 148 double event cutsets and these are listed in Table 1.5.2.3.5-6. Only single and double cutsets are evaluated.

1.5.2.3.5.3.4.2 NaOH addition. Considering only random hardware failure as in Section 1.5.2.3.5.3.4.1 above, there are four single event cutsets in the NaOH addition system as shown in the fault tree, Figure 1.5.2.3.5-7 . These are:

- CTKNAOHG. Plugging of (or failure to obtain solution from) the spray additive tank.
- CXV1841Q. Mechanical failure closed of tank valve 1841 (a locked open valve).
- CXV873BX. Locked closed test valve 873B left open (human error).
- SASCAOVK. No automatic open signal to AOVs 876A and 876B.

The demand failure frequencies of these single failure points are given in Section 1.5.2.3.5.4.

There are 17 double event cutsets. Both single and double cutsets are listed in Table 1.5.2.3.5-7. These are all of the possible random hardware failure cutsets for the fault tree logic model.

1.5.2.3.5.4 Quantification.

1.5.2.3.5.4.1 Containment Spray.

1.5.2.3.5.4.1.1 System states. Whenever the reactor is not shut down, this system will be in one of the following three states:

1. Neither train out for test or maintenance.
2. One or the other train out for maintenance.
3. One or the other train out for test.

Based upon plant specific data, a containment spray pump is unavailable due to testing for an average of 45 ± 15 minutes each 30 days/month. (The tolerance noted is an estimate.)

Train unavailable due to test:

Mean: 0.001; 1.0×10^{-3}

Variance: 5.9×10^{-8}

During the period 1977 to 1980, three maintenance events have been performed on the containment spray pumps. The total cumulative pump hours are 35,664 and the average out of service time is 5 hours per event (out of service time cannot exceed 24 hours because of operating limits).

Train unavailable due to maintenance:

Mean: 8.1×10^{-4}

Variance: 6.4×10^{-8}

These state values are the conditional events for the INHIBIT gate shown in the fault tree, Figure 1.5.2.3.5-6, sheet 1.

1.5.2.3.5.4.1.2 Input condition. Two input conditions have been considered:

1. Both 480 VAC buses available
2. Bus 5A or Bus 6A failed

These conditions are evaluated as ON/OFF events. Failure rate data used in subsequent quantifications are summarized in Table 1.5.2.3.5-4.

1.5.2.3.5.4.1.3 Both 480VAC buses available.

- Random Hardware Failures. For train A or B, the following is the quantification of random hardware failures (refer to Table 1.5.2.3.5-4 for data):

  - Locked open valve 865 mechanical closing and considering monthly inspections:

    Mean α_{XV_1}: $7.4 \times 10^{-8} \times \frac{730}{2} = 2.7 \times 10^{-5}$

    Variance: 7.4×10^{-10}

  - Spray pump and motor 21 (or 22) the failure to start and failure to run an average of 120 minutes:

    Mean α_p: 6.5×10^{-3}

    Variance: 7.4×10^{-6}

  - Two parallel MOVs 866 fail to open:

    Mean α_{MV}: $(MOV)^2 = 6.5 \times 10^{-6}$

    Variance: 5.3×10^{-11}

  - Check valve 867 stuck closed;

    Mean α_{CV}: 7.0×10^{-5}

    Variance: 1.1×10^{-8}

  - Locked open containment manual valve 869 closing mechanical (as for valve 865):

    Mean α_{XV_2}: 2.7×10^{-5}*

    Variance: 7.4×10^{-10}

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*During final review of the containment spray system analysis, it was realized that the frequency of flow verification testing for manual valves 869A and 869B, the manual containment isolation valves, occurs every refueling cycle (18 months), rather than every month as was assumed initially. This changes the failure frequency of this valve to a mean of 4.8×10^{-4} and a variance of 2.4×10^{-7}, which results in an increase of the frequency of failure of a single pump train to a mean of 7.0×10^{-3} and a variance of 7.5×10^{-6}. The mean frequency of system failure after this change is 8.2×10^{-5} (compared to 7.5×10^{-5}); therefore, this revised value has no significant effect on the dominant plant damage states. For the single bus cases, the frequency of system failure after the correction is 1.06×10^{-2} (compared to 1.00×10^{-2}); therefore, this revised value also has no significant effect on the dominant plant damage states. Since these corrected values had no significant effect on the results, they were not propagated through the systems or plant analyses.

- Spray nozzles (221) plugging sufficient to cause system failure. The spray nozzles and spray headers are maintained in a dry condition and are inspected every 5 years. Because of the environment in which these nozzles exist, large scale corrosion sufficient to plug the spray nozzles will not occur. For this reason, the frequency of plugging of the spray nozzles is assigned a negligibly small frequency.

  The one single cutset event for the system is plugging of the 10-inch diameter suction header (rupture would be immediately detected because of the large amount of water released). The probability of plugging this large a diameter pipe is considered remote. The most likely cause would be ice in the 12-inch diameter line from the RWST, but that line is heated above ground or is buried. Therefore, the influence of line plugging is not significant and not quantified.

- Failure of One Train. Summing the means for the components in one train:

  Mean: 6.9×10^{-3}

  Variance: 7.4×10^{-6}

- Total Random Failures. For the state condition of neither containment spray train A or B out for test or maintenance, the unavailability of the complete system because of random hardware failures using DPD arithmetic is:

  Mean CS_R: $(\text{pump train})^2 = 5.1 \times 10^{-5}$

- One Train Out For Maintenance. For the state conditions of train A or B out for maintenance (state availability) and random failure of the other train:

  Mean CS_M: $2(6.9 \times 10^{-3})(8.1 \times 10^{-4}) = 1.1 \times 10^{-5}$

- One Train Out For Test. For the state conditions of train A or B out for test (state availability) and the failure to reopen valve 869A or 869B, the unavailability is:

  Mean CS_T: $2(6.9 \times 10^{-3})(1.0 \times 10^{-3})(9.0 \times 10^{-3})^* = 1.2 \times 10^{-7}$

- Human Error. Each train is tested monthly. This test requires that the manual containment isolation valve 869A or 869B for the pump train under test be closed. The human error for this event includes the error of omission, failing to reopen the valve, and the probability of not discovering the error of omission. From the chapter on human error rates, the human error rates (presented in the following) for these two errors are used.

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*The value (9.0×10^{-3}) is used for event CXV869AQ(or CXV869BS) because it is judged that, following a LOCA which occurs when a train flow test is being performed, the operator may not think of opening the containment isolation valve.

Error	Mean	Variance
1. Failure to restore valve to proper position	9.0×10^{-3}	1.8×10^{-4}
2. Failure to discover error	2.2×10^{-2}	1.9×10^{-3}

The following expression defines the contribution of this human error to system failure:

$$Q_{\text{Human Error}} = P_{(\text{both})} P_{(\text{nondiscovery})} + 2P_{(\text{one})} P_{(\text{nondiscovery})} P_{(\text{pump train})}$$

$P_{(\text{both})}$ is the frequency of both valves being closed due to operator error. With low dependencies between the actions, $P_{(\text{both})}$:

$$P_{(\text{both})} = P_{(\text{one})}\left[\frac{1 + 19\ P_{(\text{one})}}{20}\right]$$

$P_{(\text{nondiscovery})}$ = the probability of not discovering the error of omission.

$P_{(\text{one})}$ = the frequency for a single valve being closed due to operator error.

$P_{(\text{pump train})}$ = the frequency of failure of a single pump train due to random failures.

The human error contribution is:

Mean, CS_H: 1.4×10^{-5}

Variance: 1.3×10^{-9}

- Common Cause. Common cause failures of the same type of component in different trains could occur, but the probability in a standby system that is tested monthly and can be maintained during reactor operation is judged to be very small. Additionally, common external causes such as fire or flooding are evaluated elsewhere in this study and are incorporated in the event mitigating sequences. Therefore, no common cause contribution has been assigned to this system.

- Total Unavailability--Electric Power Available. Total containment spray system unavailability when electric power is available (normal and emergency) is:

  Mean CS_{sys}: $CS_R + CS_M + CS_T + CS_H = 7.5 \times 10^{-5}$

  Variance: 2.9×10^{-9}

  Table 1.5.2.3.5-8 lists the dominant causes and effects.

1.5.2.3.5.4.1.4 Bus 5A (or 6A) failed. Failure of one main bus 5A or 6A will disable one train. The other train will be unaffected. The following expression defines the frequency of system failure given loss of power to a single 480VAC bus:

$$Q_{system} = P_{(pump\ train)} + P_{(maintenance)} + P_{(test)}$$

$$+ P_{(both)}\ P_{(nondiscovery)} + P_{(one)}\ P_{(nondiscovery)}$$

Loss of one 480V bus also results in loss of one of the two parallel motor-operated valves in each pump train. This results in the following frequency of failure of a single pump train with a loss of one 480V bus:

$Mean_{pump\ train}$: 8.9×10^{-3}

Variance: 8.5×10^{-6}

The frequency of system failure, given a loss of a single 480V bus is now:

Mean CS_{system}: 1.0×10^{-2}

Variance: 7.1×10^{-6}

Table 1.5.2.3.5-9 lists the major causes of system failure and system unavailability given that bus 5A or 6A is unavailable.

1.5.2.3.5.4.1.5 Pipe failures. Pipe failures in the containment spray system have been evaluated quantitatively in Table 1.5.2.3.5-10. Plugging of the lines would be detected monthly. Rupture would be readily detected because of the large amount of water that would be released, even if the system were not operating. Plugging of these large diameter pipes is considered very improbable.

There is a slight possibility of line rupture during system operation. Using the value of 8.6×10^{-10} occurrences/hour per section for rupture, the four sections in this system result in an overall failure of 3.4×10^{-9}/hour. Allowing for a 2-hour system run time, the unavailability would be 6.8×10^{-9} and would not change the system unavailability values calculated.

1.5.2.3.5.4.2 NaOH Addition.

1.5.2.3.5.4.2.1 System states. This system has two states:

1. Both containment spray trains operative.
2. One or the other containment spray train inoperative.

1.5.2.3.5.4.2.2 Random hardware failures. There are three single failures which will cause system failure:

1. No NaOH from tank.
2. Valve 1841 not open.
3. Valve 873B not closed.

In addition, if neither AOV 876A nor AOV 876B open, system failure will occur.

Failure to obtain NaOH solution from the spray additive tank is expected with a frequency of: mean = 2.0×10^{-6}/hr. The causes of failure include vacuum breaker not open, no solution in tank, plugging of the outlet, tank rupture, etc. The tank is inspected monthly so the mean out of service time is 365 hours. The unavailability is:

Mean α_{TK}: $(2.0 \times 10^{-6})(365) = 7.3 \times 10^{-4}$

Variance: 7.9×10^{-8}

Manual valve 1841 at the tank outlet can fail mechanically to the closed position which is expected to occur with a frequency of:

Mean α_{V_1}: 2.7×10^{-5}

Variance: 7.4×10^{-10}

Manual valve 873B from the RWST for eductor flushing will cause system failure if it is not closed following the monthly system test. This is a human error which will be considered later.

Failure of both air-operated valves from the spray additive tank to open will cause system failure. These are fail open valves but could mechanically fail to open with a frequency of: mean = 7.5×10^{-4}, variance = 4.0×10^{-7}. Failure of both valves is:

Mean α_{V_2}: 9.4×10^{-7}

Variance: 6.5×10^{-12}

The sum of the single random failure contribution to NaOH system failure is:

Mean: 7.6×10^{-4}

Variance: 7.8×10^{-8}

An eductor train consists of a manual valve, check valve, and eductor. These serial components are summed as follows:

Component Failure	Mean	Variance
Manual valve 1839, not open	2.7×10^{-5}	7.4×10^{-10}
Check valve 1838, stuck shut	7.0×10^{-5}	1.1×10^{-8}
Eductor, plugged	2.4×10^{-4}	3.3×10^{-7}
Total eductor train 21 or 22	3.4×10^{-4}	2.7×10^{-7}

When both containment spray trains are operating, the unavailability of both eductor trains is:

Mean α_E: 3.8×10^{-7}

Variance: 1.0×10^{-11}

When only one containment spray train is operating:

Mean α_{E_1}: 3.4×10^{-4}

Variance: 2.7×10^{-7}

- Test. When the containment spray system is tested, the eductors are also tested; therefore, the unavailability for test of this system has been accounted for in the containment spray unavailability.

- Maintenance. Any maintenance that is performed on the spray additive tank requires that the plant be shut down.

- Human Error. Failure to reclose valve 873B from the RWST following an eductor test will render the NaOH system ineffective. This type of failure is composed of two types of human errors: (1) failure to reposition a valve after completing a test (due perhaps to a change in shift), and (2) failure of a second operator to discover the mistake. Using the error rates shown in Section 1.5.2.3.5.4.1, the human error contribution to the system unavailability is:

  Mean NA_H: 2.0×10^{-4}

  Variance: 2.4×10^{-7}

- Common Cause. Both eductor trains could fail due to plugging of the eductors by sediment from the spray additive tank. Using a beta factor of 1.0×10^{-2} (or once in 100 years) and the value for NaOH eductor train unavailability given that containment spray is available, common cause failures of system will occur with the following frequency assuming the probability of sediment is 1.0×10^{-4}:

  Mean NA_C: $(3.1 \times 10^{-4})(1.0 \times 10^{-2})(1 - 6.5 \times 10^{-3})(1.0 \times 10^{-4})$

  $= 3.1 \times 10^{-10}$

- Pipe Failures. Pipe failures in the NaOH system have been evaluated qualititively in Table 1.5.2.3.5-11. There are three pipe section failures which will fail that train (one pipe failure from the spray additive tank causes system failure). As discussed in Section 1.5.2.3.5.4.1.6, the resulting unavailabilities do not alter significantly after the system values calculated previously.

- Total Unavailability. The total NaOH unavailability for the case "Both 480V Buses Available" is:

  Mean NA_{sys}: 9.6×10^{-4}

  Variance: 2.8×10^{-7}

  This result is dominated by the random hardware failures of the system.

  With power available at only one 480V bus, only one spray pump train is available. Under this condition, the unavailability of the NaOH system is:

  Mean NA_{sys}: 1.3×10^{-3}

  Variance: 1.4×10^{-5}

  The result is dominated by random failure in the spray additive tank, the tank outlet valves, and the eductor train.

Tables 1.5.2.3.5-12 and 1.5.2.3.5-13 summarize the causes of NaOH addition system failure.

1.5.2.3.5.4.3 Statistical Summary. The results of the systems' quantification have been summarized in Table 1.5.2.3.5-1. Median and percentile values were calculated by the computer program DPD using component means and variances and system reliability equations.

TABLE 1.5.2.3.5-1

INDIAN POINT 2 SUMMARY OF RESULTS

CONTAINMENT SPRAY

Condition	Mean	Variance	5th Percentile	Median	95th Percentile
Electric power to buses 5A and 6A	7.5×10^{-5}	2.9×10^{-9}	2.0×10^{-5}	5.0×10^{-5}	1.5×10^{-4}
No electric power to one bus (5A or 6A)	1.0×10^{-2}	7.1×10^{-6}	6.1×10^{-3}	9.1×10^{-3}	1.4×10^{-2}
WASH-1400	-	-	1.0×10^{-3}	2.4×10^{-3}	7.8×10^{-3}

SODIUM HYDROXIDE ADDITION

Condition	Mean	Variance	5th Percentile	Median	95th Percentile
Electric power to buses 5A and 6A	9.6×10^{-4}	2.8×10^{-7}	4.5×10^{-4}	8.3×10^{-4}	1.5×10^{-3}
No electric power to one bus (5A or 6A)	1.3×10^{-3}	1.4×10^{-5}	1.5×10^{-4}	9.9×10^{-4}	6.4×10^{-3}
WASH-1400	-	-	3.6×10^{-3}	5.9×10^{-3}	1.1×10^{-2}

TABLE 1.5.2.3.5-2

INDIAN POINT 2 ELECTRICAL INTERFACES

Component	Power Supply
Containment Spray Pump 21	480 VAC Bus 5A and Breaker 52/CS1
Containment Spray Pump 22	480 VAC Bus 6A and Breaker 52/CS2
Discharge Stop Valves:	
MOVs 866A and 866C	MCC 26A (Bus 5A)
MOVs 866B and 866D	MCC 26B (Bus 6A)

TABLE 1.5.2.3.5-3

INDIAN POINT 2 TESTING AND INSPECTION

Component	Test/Inspection	Frequency	Reference
Spray Pumps 21 and 22	Start and run for 20 minutes minimum	Monthly	ASME, Section XI, Inservice Testing Requirement
Discharge Stop Valves MOV866A-D	Verify opened and closed	Monthly (as part of pump test) and quarterly	ASME, Section XI, Inservice Testing Requirement
Containment Isolation Valves	Verify closed and opened	Monthly	Plant Procedures
Eductors	Verify not plugged	Monthly and quarterly	Plant Procedures
Locked Valves (all)	Verify locked in proper position	Monthly	Plant Procedures
Spray Additive Tank Level	Verify 72% full	Quarterly	Plant Procedures
NaOH Concentration in Spray Additive Tank	Verify 30% minimum by weight	Monthly	Appendix A to License DPR-26 Technical Specification and Basis
Spray Nozzles	Flow check	Every 5 years	Appendix A to License DPR-26 Technical Specification and Basis

TABLE 1.5.2.3.5-4

INDIAN POINT 2 CONTAINMENT SPRAY SYSTEM COMPONENT DATA

Component and Fault Tree Code	Failure Mode	Normal State	Failure Rate Mean/Variance [Demand (D) or Hourly (H)]	Data Source Table 1.5.1.4 (item number)
Motor Operated Valve				
CMV 866AQ	Failure to open	Closed	2.3×10^{-3}/ 1.2×10^{-6} [D]	6
CMV 866BQ	Failure to open	Closed		
CMV 866CQ	Failure to open	Closed		
CMV 866DQ	Failure to open	Closed		
Manually Operated Valve				
CXV 865AQ	Fails closed	Locked open	7.4×10^{-8}/ 5.9×10^{-15} [H]	1
CXV 865BQ	Fails closed	Locked open		
CXV 869AQ	Fails closed	Locked open		
CXV 869BQ	Fails closed	Locked open		
CXV 869AC	Left closed	Locked open	Human Error	See text
CXV 869BC	Left closed	Locked open		
Check Valve				
CCV 867AQ	Failure to open	Closed	7.0×10^{-5}/ 1.1×10^{-8} [D]	3
CCV 867BQ	Failure to open	Closed		

TABLE 1.5.2.3.5-4 (continued)

INDIAN POINT 2 CONTAINMENT SPRAY SYSTEM COMPONENT DATA

Component and Fault Tree Code	Failure Mode	Normal State	Failure Rate Mean/Variance [Demand (D) or Hourly (H)]	Data Source Table 1.5.1.4 (item number)
Containment Spray Pump and Motor				
CPMCS21N	Does not start or stops before 2 hours	Not running	6.41×10^{-3}/ 7.78×10^{-6} [D]	11 and 19
CPMCS22N	Does not start or stops before 2 hours	Not running	1.65×10^{-5} 2.18×10^{-8} [H]	
Spray Nozzle Sets				
CNZ221AG	Plugging 50%	Passive	ε	(Estimated on the basis of engineering judgment)
CNZ221BG	Plugging 50%	Passive		

ε = insignificant contribution to failure.

TABLE 1.5.2.3.5-5

INDIAN POINT 2 SODIUM HYDROXIDE ADDITION SYSTEM COMPONENT DATA

Component and Fault Tree Code	Failure Mode	Normal State	Failure Rate Mean/Variance [Demand (D) or Hourly (H)]	Data Source Table 1.5.1.4 (item number)
Air-Operated Valves				
CAV 876AQ	Failure to open	Closed	7.5×10^{-4}/	8
CAV 876BQ	Failure to open	Closed	4.0×10^{-7} [D]	
Manual Valves				
CXV 873BX	Left open	Locked closed	Human Error	See text
CXV 1841Q	Fails closed	Locked open	7.4×10^{-8}/	1
CXV 839AQ	Fails closed	Locked open	5.9×10^{-15} [H]	
CXV 839BQ	Fails closed	Locked open		
Check Valves				
CCV 838AQ	Failure to open	Open	7.0×10^{-5}/	3
CCV 838BQ	Failure to open	Open	1.1×10^{-8} [D]	
Eductor				
CET0021G	Plugged	Passive	2.4×10^{-4}/	(Estimated on the basis of engineering judgment.)
CET0022G	Plugged	Passive	3.3×10^{-7} [D]	
Spray Additive Tank				
CTKNAOHG	Failure to supply NaOH solution to system	Full	2.0×10^{-6}/ 6.1×10^{-13} [H]	(Estimated on the basis of engineering judgment)

TABLE 1.5.2.3.5-6

INDIAN POINT 2 CONTAINMENT SPRAY (CS) SYSTEM--INJECTION PHASE

Cutsets with One Basic Event

3)	1)	CCS0000X	2)	CPP151RG	3)	CPS000X

Cutsets with Two Basic Events

7)	1)	CMV866BQ	CMV866AQ	2)	CMV866BQ	CCB15BX	3)	CMV866BQ	CMOCS31T	4)	CMV866BQ	CPMCS31P
11)	5)	CMV866BQ	CXV865AQ	6)	CMV866BQ	CCV867AQ	7)	CMV866BQ	CXV869AQ	8)	CMV866BQ	CSN221AG
15)	9)	CSN221AG	CCB12AX	10)	CSN221AG	CMOCS32T	11)	CSN221AG	CPMCS32P	12)	CSN221AG	CXV865BQ
19)	10)	CSN221AG	CCV867BQ	14)	CSN221AG	CXV869BQ	15)	CSN221AG	CSN221BG	16)	CXV869AQ	CCB12AX
23)	17)	CXV869AQ	CMOCS32T	18)	CXV869AQ	CPMCS32P	19)	CXV869AQ	CXV865BQ	20)	CXV869AQ	CCV867BQ
27)	21)	CXV869AQ	CXV869BQ	22)	CXV869AQ	CSN221BG	23)	CCV867AQ	CCB12AX	24)	CCV867AQ	CMOCS32T
31)	25)	CCV867AQ	CPMCS32P	26)	CCV867AQ	CXV865BQ	27)	CCV867AQ	CCV867BQ	28)	CCV867AQ	CXV869BQ
35)	29)	CCV867AQ	CSN221BG	30)	CXV865AQ	CCB12AX	31)	CXV865AQ	CMOCS32T	32)	CXV865AQ	CPMCS32P
39)	33)	CXV865AQ	CXV865BQ	34)	CXV865AQ	CCV867BQ	35)	CXV865AQ	CXV869BQ	36)	CXV865AQ	CSN221BG
43)	37)	CCB15BX	CCB12AX	38)	CMOCS31T	CCB12AX	39)	CPMCS31P	CCB12AX	40)	CCB15BX	CMOCS32T
47)	41)	CMOCS31T	CMOCS32T	42)	CPMCS31P	CMOCS32T	43)	CCB15BX	CPMCS32P	44)	CMOCS31T	CPMCS32P
51)	45)	CPMCS31P	CPMCS32P	46)	CCB15BX	CXV865BQ	47)	CMOCS31T	CXV865BQ	48)	CPMCS31P	CXV865BQ
55)	49)	CCB15BX	CCV867BQ	50)	CMOCS31T	CCV867BQ	51)	CPMCS31P	CCV867BQ	52)	CCB15BX	CXV869BQ
59)	53)	CMOCS31T	CXV869BQ	54)	CPMCS31P	CXV869BQ	55)	CCB15BX	CSN221BG	56)	CMOCS31T	CSN221BG
63)	57)	CPMCS31P	CSN221BG	58)	CMV866AQ	CCB12AX	59)	CMV866AQ	CMOCS32T	60)	CMV866AQ	CPMCS32P
67)	61)	CMV866AQ	CXV865BQ	62)	CMV866AQ	CCV867BQ	63)	CMV866AQ	CXV869BQ	64)	CMV866AQ	CSN221BG
71)	65)	CSN221AG	JBS36BK	66)	CXV869AQ	JBS36BK	67)	CCV867AQ	JBS36BK	68)	CXV865AQ	JBS36BK
75)	69)	CCB15BX	JBS36BK	70)	CMOCS31T	JBS36BK	71)	CPMCS31P	JBS36BK	72)	CMV866AQ	JBS36BK
79)	73)	CMV866BQ	JBS36AK	74)	JBS36AK	CCB12AX	75)	JBS36AK	CMOCS32T	76)	JBS36AK	CPMCS32P
83)	77)	JBS36AK	CXV865BQ	78)	JBS36AK	CCV867BQ	79)	JBS36AK	CXV869BQ	80)	JBS36AK	CSN221BG
84)	81)	JBS36AK	JBS36BK									

TABLE 1.5.2.3.5-7

INDIAN POINT 2 SODIUM HYDROXIDE ADDITION (NA) WITHOUT TEST AND MAINTENANCE

Cutsets with One Basic Event

4)	1)	CTKNADHG	2)	CXV1841Q	3)	CXV873BX	4)	SASCAOVK			

Cutsets with Two Basic Events

8)	1)	CAV876AQ	CAV876BQ	2)	CET0022G	CET0021G	3)	CXV839BQ	CET0021G	4)	CCV838BQ	CET0021G
12)	5)	CPPLINBL	CET0021G	6)	CET0022G	CXV839AQ	7)	CXV839BQ	CXV839AQ	8)	CCV838BQ	CXV839AQ
16)	9)	CPPLINBL	CXV839AQ	10)	CET0022G	CCV838AQ	11)	CXV839BQ	CCV838AQ	12)	CCV838BQ	CCV838AQ
20)	13)	CPPLINBL	CCV838AQ	14)	CET0022G	CPPLINAL	15)	CXV839BQ	CPPLINAL	16)	CCV838BQ	CPPLINAL
21)	17)	CPPLINBL	CPPLINAL									

TABLE 1.5.2.3.5-8

INDIAN POINT 2 CONTAINMENT SPRAY SYSTEM UNAVAILABILITY [(5A) ∧ (6A)]

Cause	Mean Unavailability	Effects		
		Components	System	Other Systems
Total Random Failures	5.1×10^{-5}	Pumps or Valves	Fails	
Maintenance	1.1×10^{-5}	Pumps or Valves	Fails	
Testing	1.2×10^{-7}	Each Train	Fails	
Human Error	1.4×10^{-5}	Manual Valves	Fails	
Common Cause	Small	Combinations of Same Type	Fails	
TOTAL	7.5×10^{-5}			

TABLE 1.5.2.3.5-9

INDIAN POINT 2 CONTAINMENT SPRAY SYSTEM UNAVAILABILITY $[(\overline{5A}) \wedge (6A)]$ or $[(5A) \wedge (\overline{6A})]$

Cause	Mean Unavailability	Effects		
		Components	System	Other Systems
Total Random Failures	8.9×10^{-3}	Pumps or Valves	Fails	
Maintenance	8.1×10^{-4}	Pumps or Valves	Fails	
Testing	9.0×10^{-6}	Each Train	Fails	
Human Error	2.0×10^{-4}	Manual Valves	Fails	
Common Cause	N/A			
TOTAL	1.0×10^{-2}			

TABLE 1.5.2.3.5-10

INDIAN POINT 2 EFFECTS OF CONTAINMENT SPRAY PIPE FAILURE

Pipe Section	Diameter (inches)	Failure Mode	Failure Effect
Line 181 from RWST to pump suction header and header to pumps	12 10	Rupture	Loss of RWST water--would be detected and unit shut down.
		Plugging	Water unavailable to system causes system failure--detected at monthly pump test.
Lines 15 and 51 from pumps discharge to spray headers	8	Rupture	No water to spray header--loss of train readily detected and isolatable.
		Plugging	No water to spray header--loss of train.

TABLE 1.5.2.3.5-11

INDIAN POINT 2 EFFECTS OF SODIUM HYDROXIDE ADDITION SYSTEM PIPE FAILURES

Pipe Section	Diameter (inches)	Failure Mode	Failure Effect
Line 187 from Spray Additive Tank	3	Rupture or Plugging	Loss of system
Lines 188 and 578 spray pump flow through eductors	3	Rupture or Plugging	Loss of eductor

TABLE 1.5.2.3.5-12

INDIAN POINT 2 SODIUM HYDROXIDE ADDITION SYSTEM UNAVAILABILITY [(5A) ∧ (6A)]

Cause	Mean Unavailability	Effects		
		Components	System	Other Systems
Total Random Hardware Failures	7.6×10^{-4}	Eductor or Valve	Fails	None
Testing	Covered by Containment Spray	-	-	-
Maintenance	None	-	-	-
Human Error	2.0×10^{-4}	Manual Valve	Fails	None
Common Cause	3.1×10^{-10}	Eductors Plug	Fails	None
Other	-			
TOTAL	9.6×10^{-4}			

TABLE 1.5.2.3.5-13

INDIAN POINT 2 SODIUM HYDROXIDE ADDITION SYSTEM UNAVAILABILITY $[(\overline{5A}) \wedge (6A)]$ or $[(5A) \wedge (\overline{6A})]$

Cause	Mean Unavailability	Effects		
		Components	System	Other Systems
Total Random Hardware Failures	1.1×10^{-3}	Eductor or Valve	Fails	None
Testing	Covered by Containment Spray	-	-	-
Maintenance	None	-	-	-
Human Error	2.0×10^{-4}	Manual Valve	Fails	None
Common Cause	3.1×10^{-10}	Eductors Plug	Fails	None
Other	-			
TOTAL	1.3×10^{-3}			

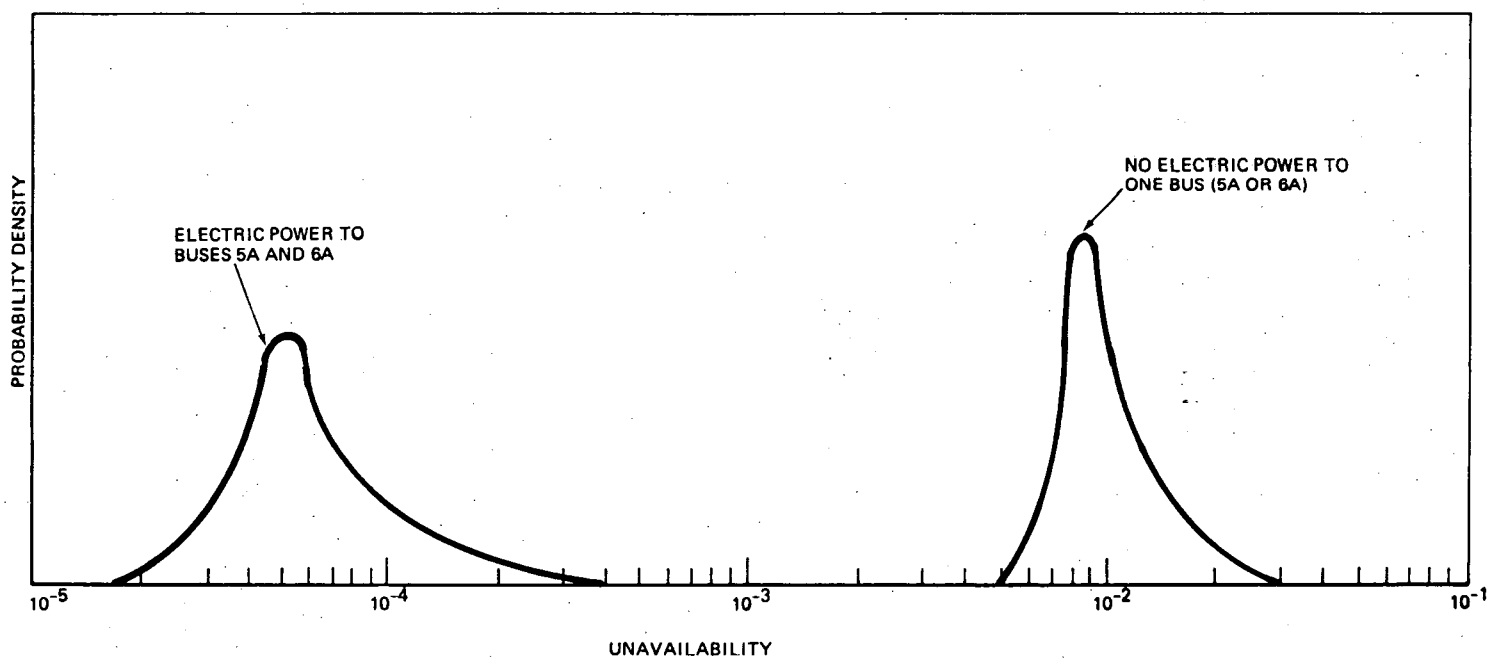


Figure 1.5.2.3.5-1. Probability Distribution of Indian Point 2 Containment Spray System Unavailability

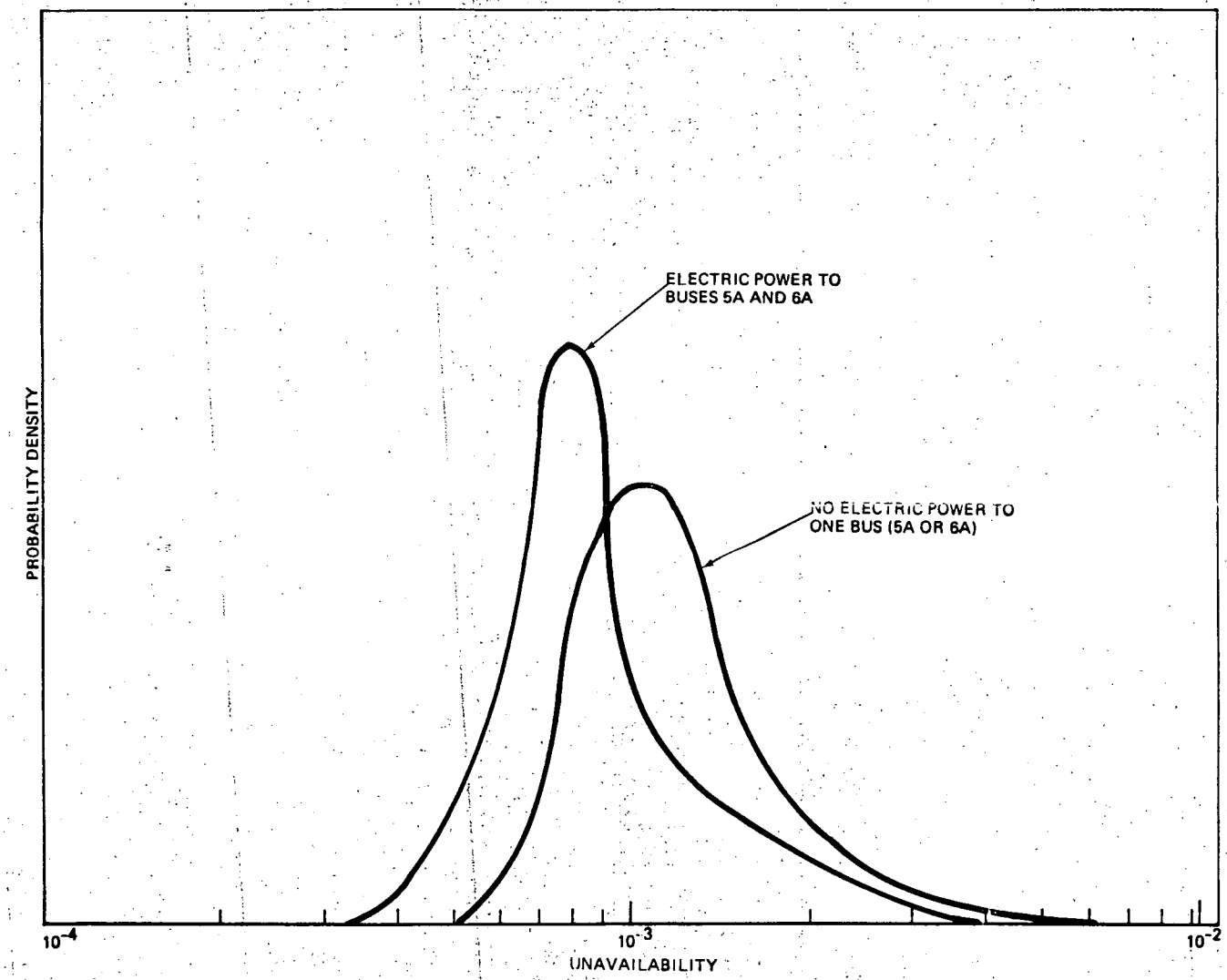


Figure 1.5.2.3.5-2. Probability Distribution of Indian Point 2 NaOH Addition System Unavailability

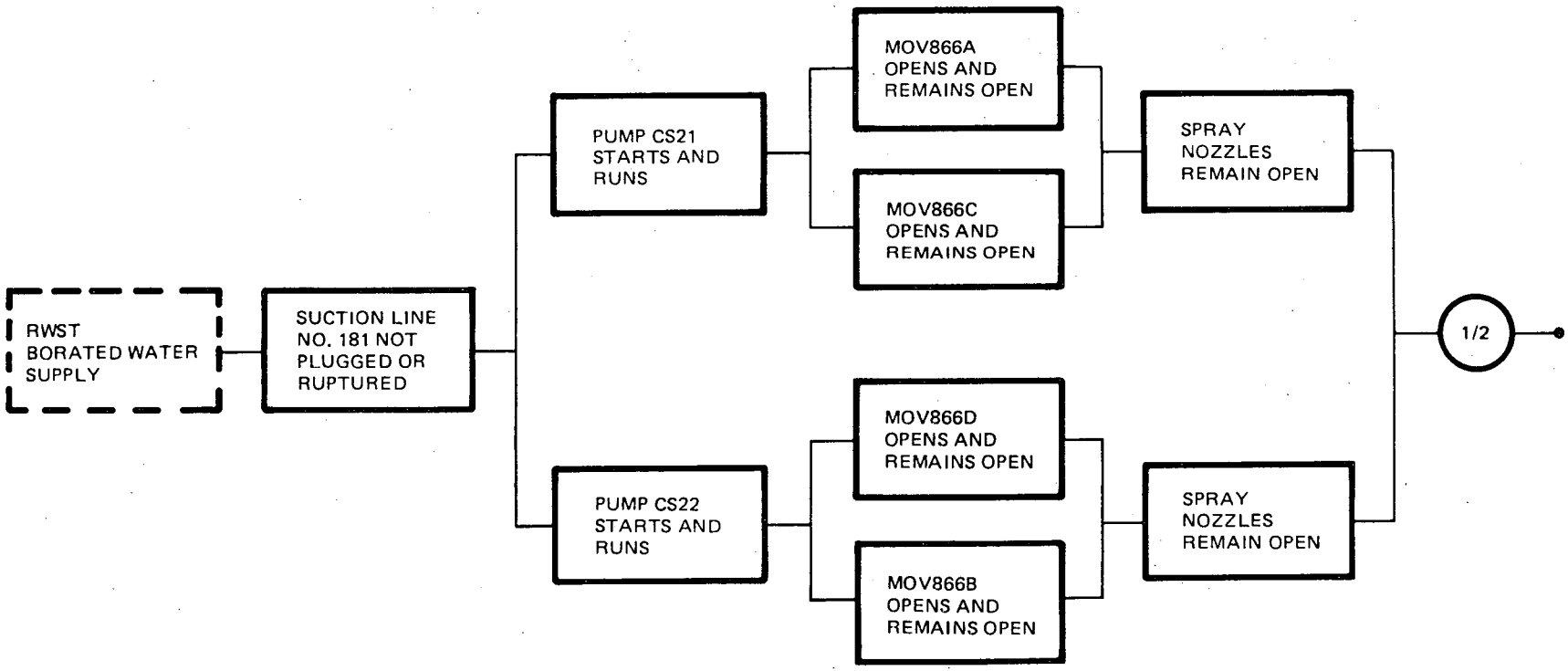


Figure 1.5.2.3.5-3. Indian Point 2 Block Diagram
Containment Spray System

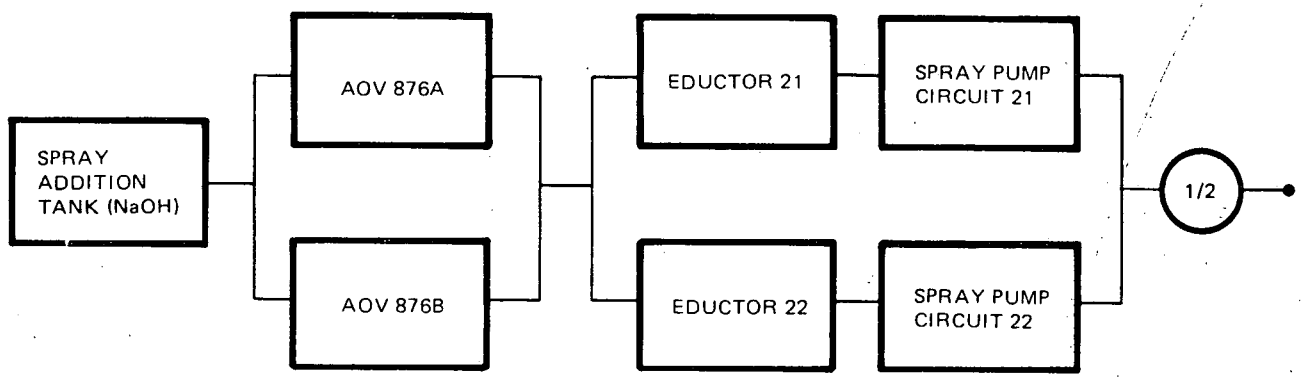


Figure 1.5.2.3.5-4. Indian Point 2 NaOH Addition System Block Diagram

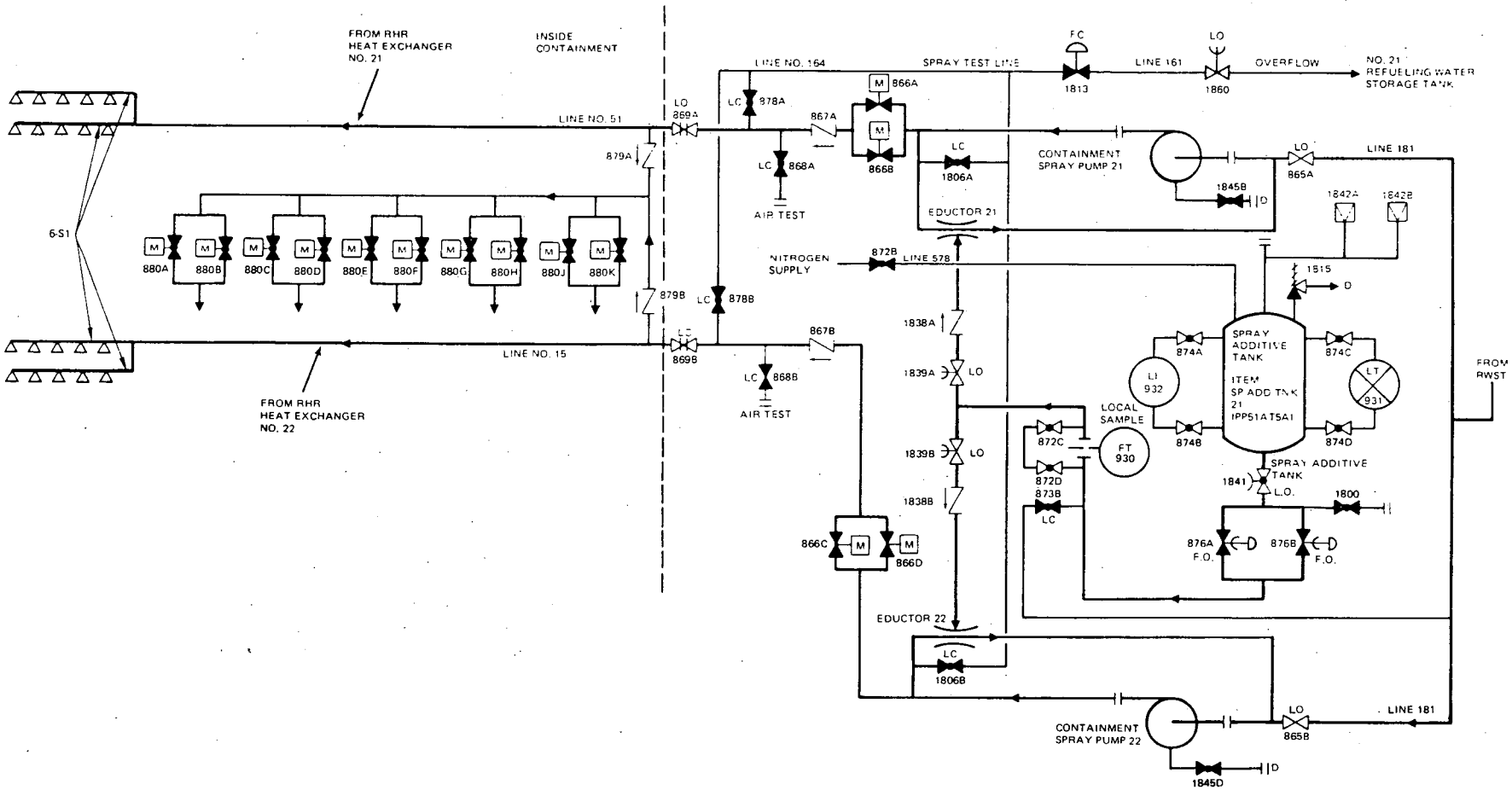


Figure 1.5.2.3.5-5. Indian Point 2 Containment Spray System Simplified P&ID

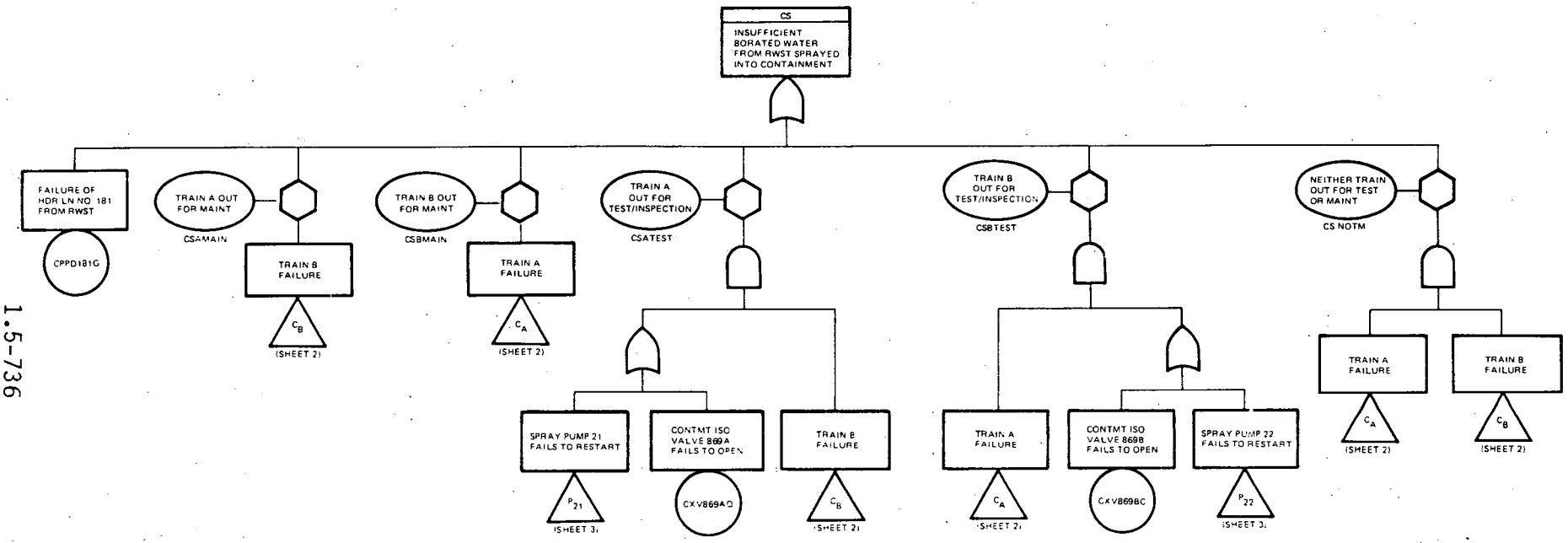
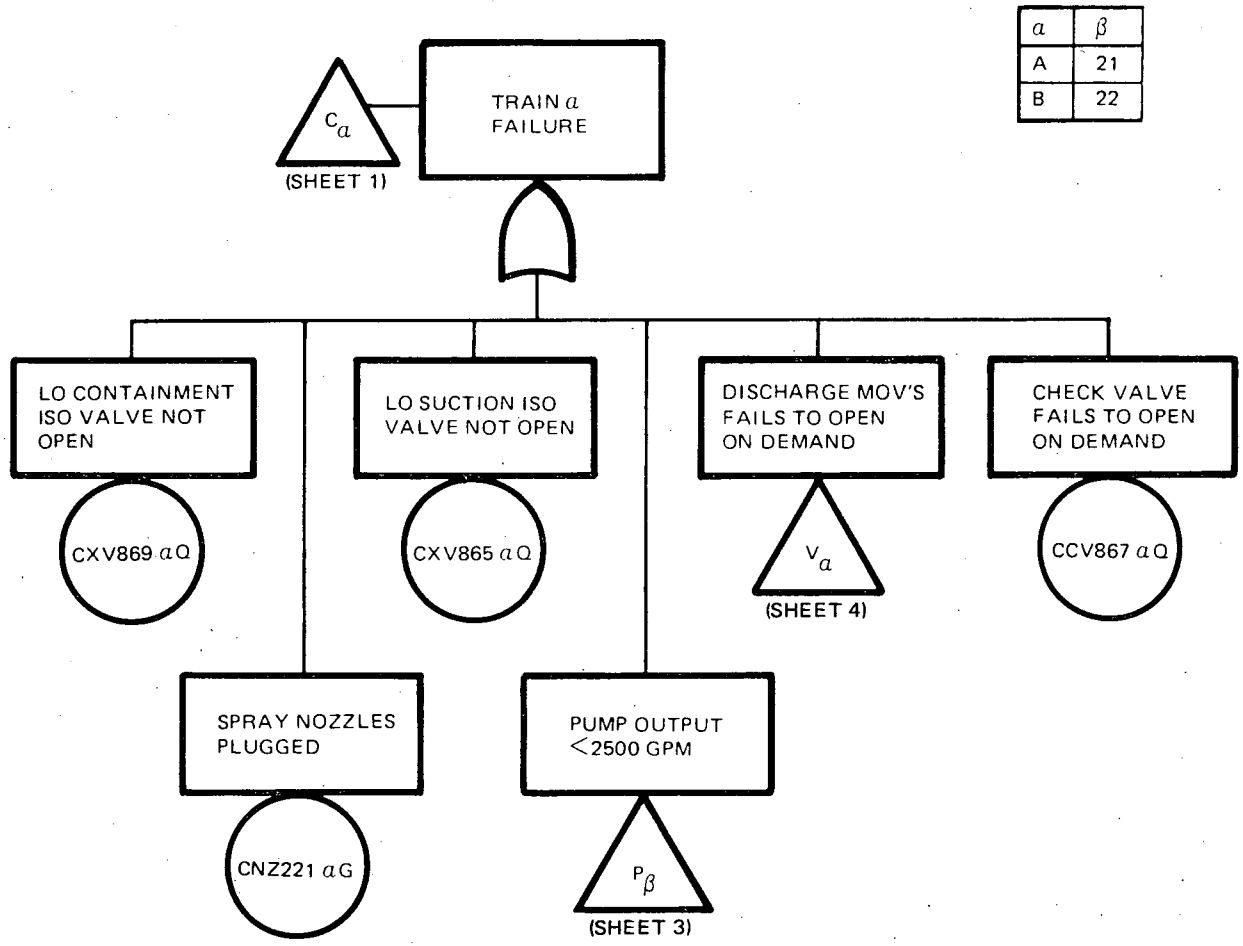
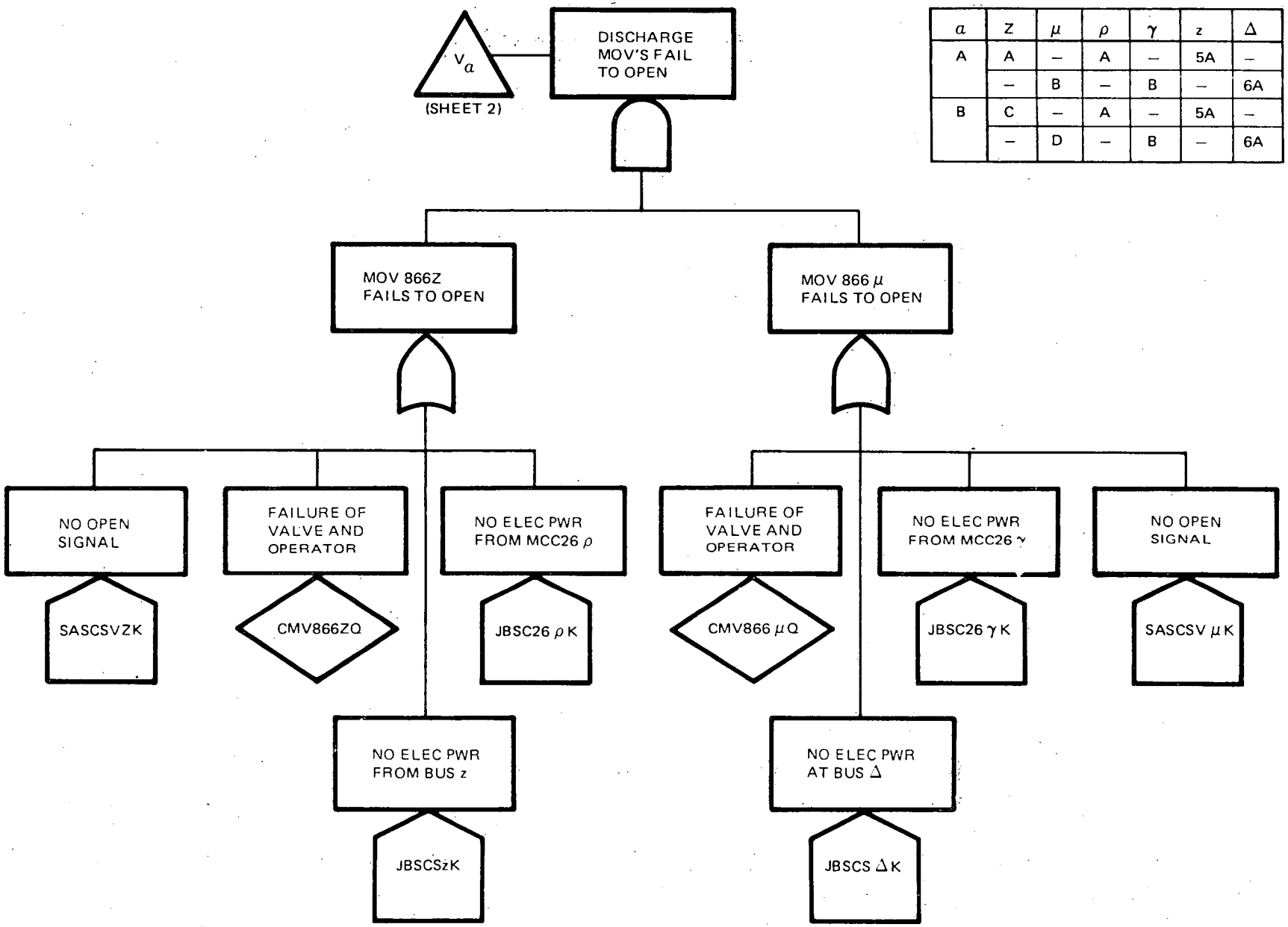


Figure 1.5.2.3.5-6. Indian Point 2 Fault Tree Diagram of Containment Spray System (Sheet 1 of 4)



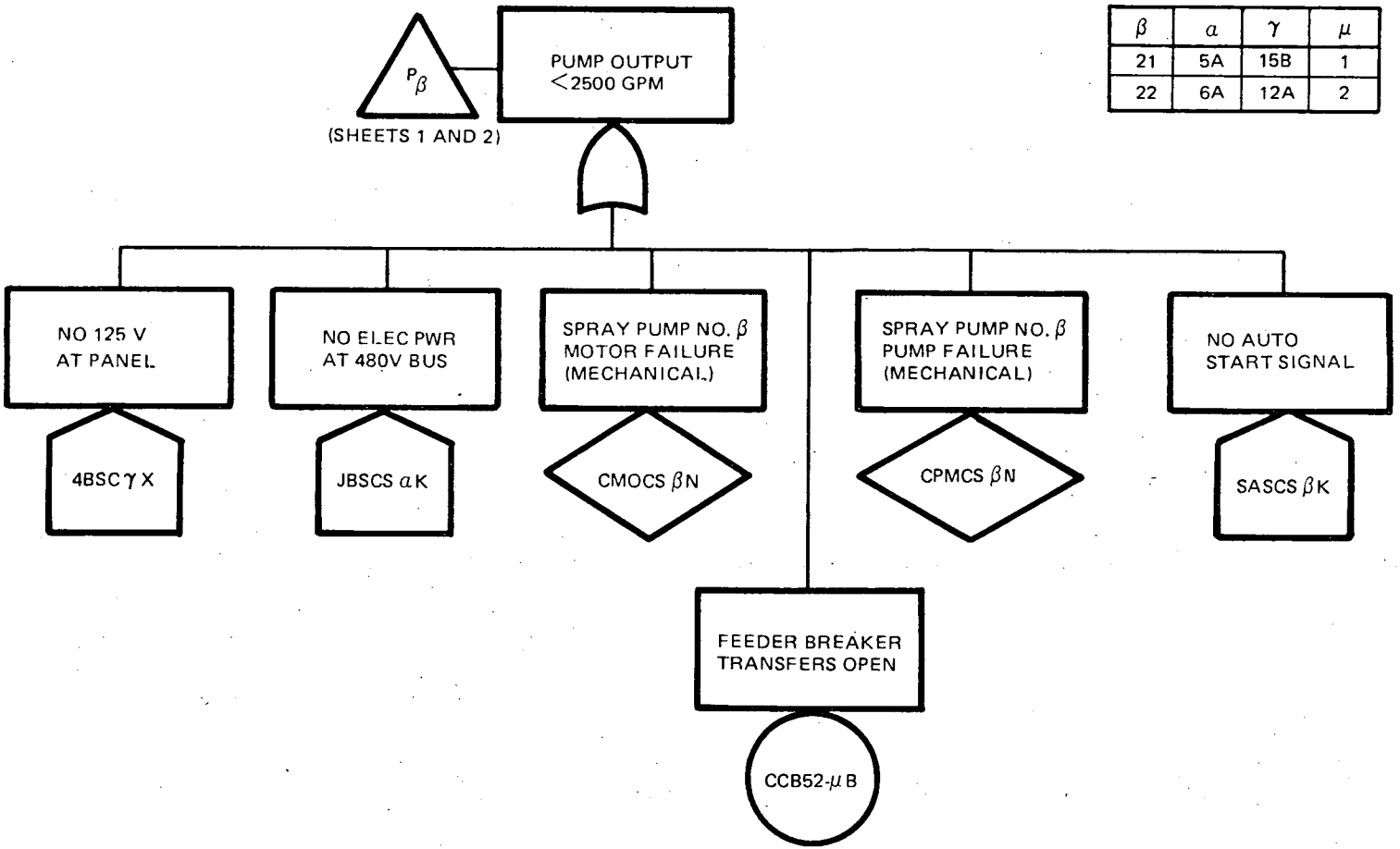
α	β
A	21
B	22

Figure 1.5.2.3.5-6. (Sheet 2 of 4)



a	Z	μ	ρ	γ	z	Δ
A	A	–	A	–	5A	–
	–	B	–	B	–	6A
B	C	–	A	–	5A	–
	–	D	–	B	–	6A

Figure 1.5.2.3.5-6. (Sheet 3 or 4)



β	α	γ	μ
21	5A	15B	1
22	6A	12A	2

Figure 1.5.2.3.5-6. (Sheet 4 of 4)

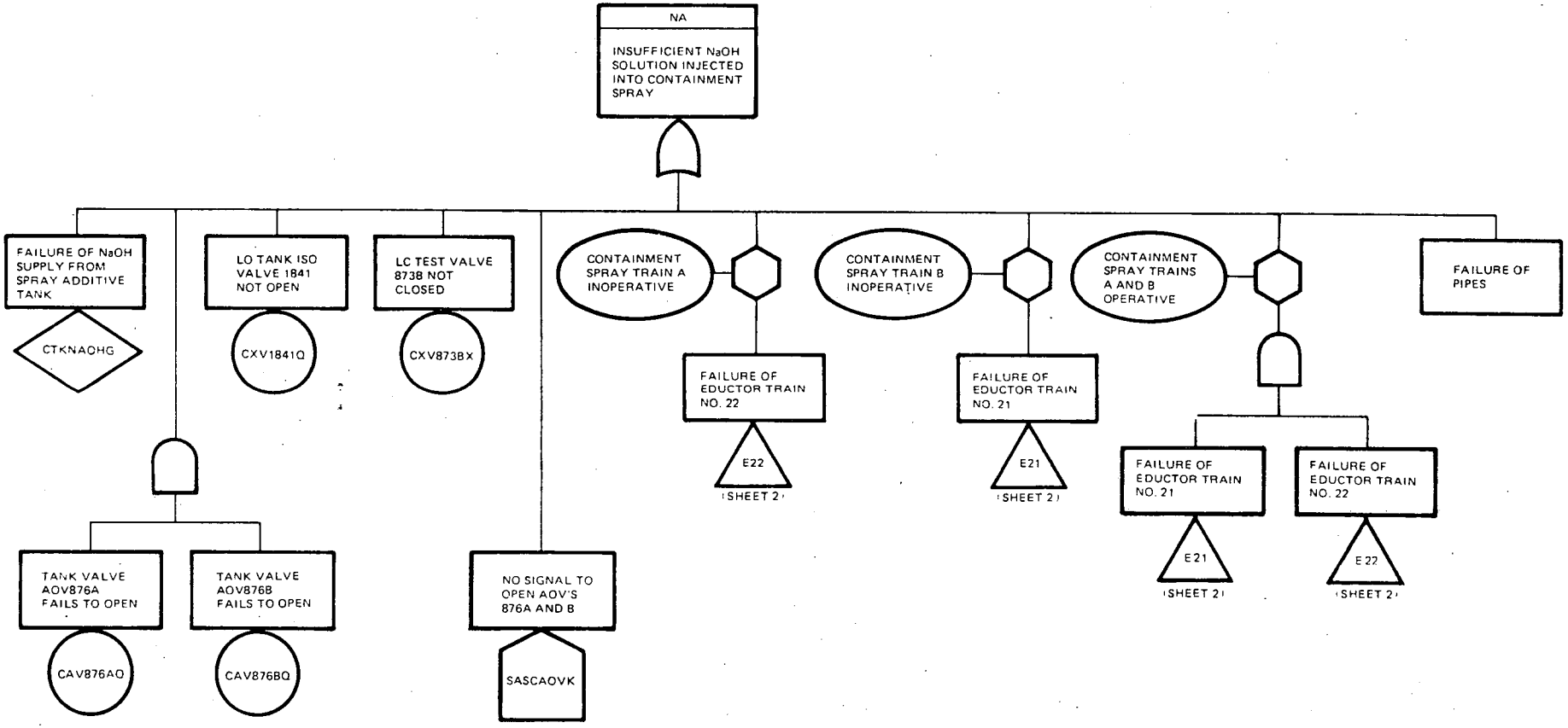
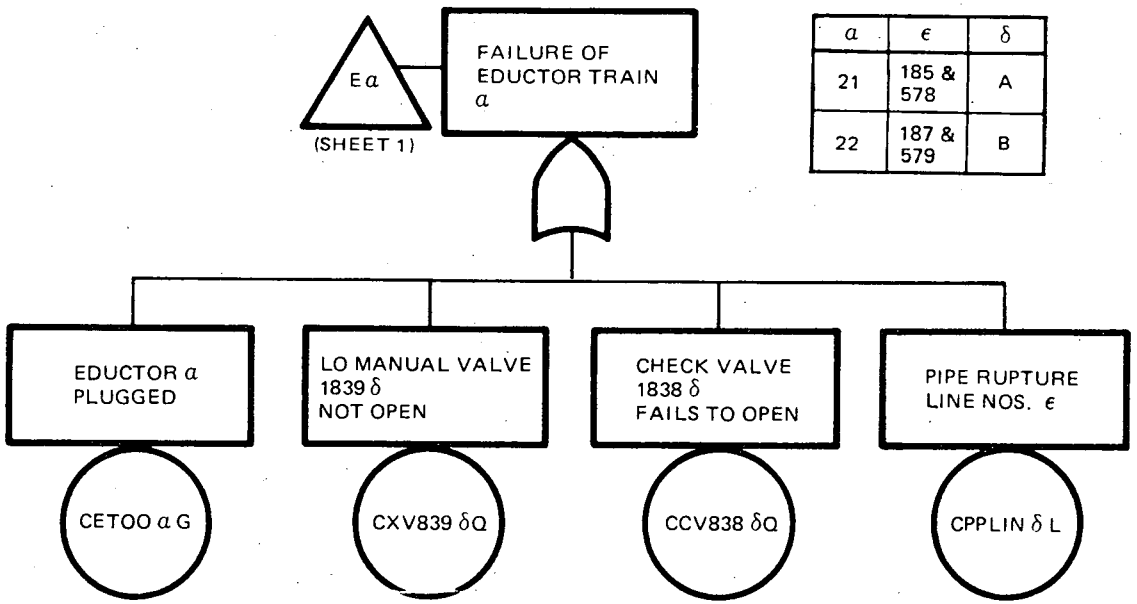


Figure 1.5.2.3.5-7. Indian Point 2 Fault Tree Diagram of NaOH Addition System (Sheet 1 of 2)



α	ε	δ
21	185 & 578	A
22	187 & 579	B

Figure 1.5.2.3.5-7. (Sheet 2 of 2)

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1.5.2.3.6 Indian Point Unit 2 Containment Fan Cooling System.

1.5.2.3.6.1 Summary.

1.5.2.3.6.1.1 Introduction. Following a loss of coolant accident (LOCA), five containment building ventilation fan cooler units are automatically transferred to their accident mode of operation. This reduces and maintains containment pressure to ensure containment integrity. Three of the five units can perform this function and can be used instead of the containment spray system.

If radioactive iodine is released to the containment as a result of the LOCA, the charcoal filter beds in each of the fan cooler units will absorb the radioactive material.

The analysis is carried out under the following conditions:

- The safeguards actuation signal is present.
- Service water is available at the isolation valves for each fan cooler unit.

1.5.2.3.6.1.2 Results. Failure of the containment fan cooling system to operate in the accident mode following activation during a safety injection (SI) sequence has been determined using generic data. These data have been updated, as applicable, with specific data from Indian Point Unit 2.

The expected unavailability of the fan cooler unit system (including iodine removal) has been calculated for those states of electric power which caused failure of less than three fan cooler units. The remaining electric power states, where power was unavailable to three or more fan cooler units, caused system failure and were not analyzed further.

The results of these calculations are summarized in Table 1.5.2.3.6-1.

The analysis showed the following dominant contributions to system unavailability:

	Mean
• With Power On All Buses	1.40×10^{-6}
- TCV 1104 and TCV 1105 fail to open	9.45×10^{-7} (68%)
- Fan cooler unit (supercomponent A) hardware failures	2.70×10^{-7} (19%)
• Bus 6A Unavailable	
- Maintenance	2.90×10^{-5} (49%)
- Three of five fan cooler units fail to start and operate	2.90×10^{-5} (49%)

- Bus (2A, 3A) or 5A Unavailable — Mean
  - Maintenance — 1.50×10^{-2} (74%)
  - Three of five fan cooler units fail to start and operate — 5.30×10^{-3} (26%)

1.5.2.3.6.1.3 Conclusions. The following cause each fan cooler unit to transfer to the accident mode of operation: the safety injection signal, which initiates internal damper shifting; the stopping and restarting of the fan motor because of automatic safeguards sequencing; and opening of the fan cooler service water discharge valves. System unavailability is increased because normally operating fan cooler units are secured and then restarted when the system is shifted to the accident mode.

The effects of maintenance on system unavailability increase significantly under less than optimum electric power states. Maintenance becomes the dominant effect when there is a failure of two fan cooler units because of electric power unavailability.

System unavailability is summarized below:

Electric Power State	Mean Unavailability
All power	1.4×10^{-6}
6A unavailable	5.9×10^{-5}
(2A, 3A) or 5A unavailable	2.0×10^{-2}

The probability distributions associated with each of the mean unavailabilities are displayed in Figure 1.5.2.3.6-1. A comparison of system unavailability was not made because of the absence of fan cooler units in the plant analyzed in the Reactor Safety Study (RSS).

1.5.2.3.6.2 System Description.

1.5.2.3.6.2.1 System Function. The primary functions of the containment cooling and iodine removal system are:

- To reduce the pressure in containment following a LOCA, or a steam line break inside containment accident.
- To remove fission products from the containment if they are released during a LOCA.

The five containment fan cooling units are used to cool the containment building atmosphere following a LOCA. The units must be transferred to their accident mode, and at least three of the five are required for a large LOCA if the containment spray system is inoperative (less than three units may be adequate in small LOCAs). Heat removed by the units is transferred to the ultimate heat sink by the service water system.

1.5.2.3.6.2.2 System Success Criteria. Any three of the five fan cooler units with their charcoal filter beds operating in the accident mode can remove heat, iodine particles, and water vapor from containment. They are also able to maintain and reduce containment pressure sufficiently to ensure containment integrity following a LOCA even without containment sprays operating.

1.5.2.3.6.2.3 Basic Description. The system has five fan cooler units, each consisting of a motor fan, cooling coils, demister, HEPA and charcoal filters, butterfly valves, and an air discharge duct. The charcoal filter assembly is normally isolated from the main air recirculation stream. In case of an accident, part of the air flow is directed through the filtration section of the unit (charcoal filter assembly) to remove volatile iodine. Duct work distributes the exhaust air to a discharge header that is common to all fan cooler units during all modes of operation. Figure 1.5.2.3.6-2 shows a simplified drawing of a fan cooler unit. The cooling water for all five fan cooling units, during both normal and accident conditions, is supplied by the service water system, as illustrated in Figure 1.5.2.3.6-3. (This configuration is based on Consolidated Edison modification commitments for the service water system.)

Each fan cooling unit has three butterfly valves. During normal operation, air flow enters through the cooling coils and exits through valve C (see Figure 1.5.2.3.6-2). The two valves (A and B) isolating the charcoal filters are shut. Four fan cooler units are normally operated in this mode to control containment humidity and temperature.

When the safeguards signal is initiated, the isolation valves (A and B) on each charcoal filtration unit are signaled to open, and the valve (C) on each normal ventilation path is signaled to close. All of these butterfly valves (3 per cooler for a total of 15) are air-operated. Electrically operated, three-way solenoid valves are used with each valve to control the instrument air supply. The butterfly valves are spring loaded and will fail to their required safeguards positions if there is a loss of instrument air and/or electric power. The safeguards

positions are the opposite of their normal operating configuration. Although valve positioning during an accident is automatic, each valve is provided with a close-open control switch and an indicating light on the SB-2 safeguards panel. Each valve also has associated amber/red indicating lights on the SB-2 safeguards panel. The amber light indicates that power is available for valve operation and the red light indicates that the valve is in the correct SI position. When any of the 15 valves changes from the normal operating position (normal path open/charcoal path closed), an alarm, "Common Control Recirculation Air Unit Valve Tripped," on the SB-1 safeguards panel annunciates.

The charcoal filters are located downstream of all the other components in the fan cooler units. They are isolated during normal operation because any air flow over the charcoal will cause deterioration. The filters are used only during an accident to remove radioactive iodine contained in the air steam mixture.

The charcoal is designed to remove both elemental (I-131) and organic iodine (CH_3I) and is 90% and 30% efficient, respectively, in this removal. The elemental iodine is removed as the mixture flows into the multitude of submicroscopic pores and is absorbed on the internal surfaces. To remove organic iodine (methyl iodine), the charcoal is impregnated with a stable form of Iodine-127. By simple mechanical interchange, methyl iodine molecules substitute for the stable I-127 contained in the charcoal and the filtered gas emerges less radioactive.

When flow is initiated through a fan cooler unit's charcoal bed, only 8,000 cfm actually flows through the charcoal. The remaining flow (57,000 cfm) passes through baffling around the filter elements.

Charcoal efficiency can be reduced by water logging or exposure to temperatures that are high enough to cause accelerated oxidation of the charcoal grain surface. To protect against this reduction, individual charcoal cells and sample pieces of charcoal are removed periodically and tested for their efficiency in iodine removal. The banks are also fitted with temperature sensing elements to warn of abnormal temperature conditions.

A system of temperature switches uniformly distributed within the charcoal beds detects and alarms the presence of fires and localized hot spots in the carbon filters. The temperature switches are set close at 400°F (this is significantly below the carbon ignition temperature of 680°F) and are wired in parallel to a common alarm for each fan cooler unit on the SI supervisory panel in the control room. Closing a single switch will actuate the alarm to indicate a high temperature in the filter plenum. On this alarm, the control room operator initiates the water dousing system that exists for each charcoal filter plenum. This system is designed to drench the absorbers thoroughly in the unlikely event of a carbon fire during the postaccident recovery. Water is obtained from the main headers of the containment spray system.

The charcoal filter compartment has a rupture disk. This disk functions independently of the mechanical equipment (isolation butterflies and their air operators) and will relieve the pressure in the compartment at a differential of 16.8 psig at 90°F.

The fans are of the centrifugal type and deliver 65,000 cfm in accident conditions and 70,000 cfm in normal conditions. The motors have "Stop-Auto-Start" switches with indicating lights on the SB-2 safeguards panel in the central control room (CCR). Pump control is also possible from a local control panel in the 480 VAC switchgear room on the 15-foot elevation of the control building. Should control be placed in "Local," the "Control Transferred to Local" alarm on the SB-1 safeguards panel would annunciate.

The motors are 350 hp, 1,200 rpm direct drive, and are fitted with heat exchangers that are cooled by service water. The supply service water is common with the service water supply to each unit's main cooling coils. The discharge from each motor heat exchanger is independent of the discharge from the main cooling coils and contains two series of motor-operated valves (MOVs) outside of containment. These can be operated remotely or locally.

Both the fan and motor are fitted with vibration detectors. Each detector can be reset (to rearm the alarm) by a common button on the SB-2 safeguards panel in the CCR. Should vibration levels reach the alarm level (initially this set point will be 0.4g above the normal zero setting for the vibraswitch with the motor operating at normal conditions), an alarm on the SB-1 safeguards panel ("Control Recirculation Fan Motor Bearing Vibration") is annunciated. At the same time, one of the five individual alarm lights next to the reset button will illuminate on the SB-2 safeguards panel.

Fan bearing temperature is also monitored. Both the inner and outer bearing temperatures for all five fans are displayed on the bearing monitor safeguards panel SK. Should either reach a temperature of 190°F, an alarm, "Bearing Monitor," on the SE safeguards panel would annunciate. The readout of the bearing monitor would indicate which bearing is hot. Overload protection for the fan motors is provided at the switchgear by overcurrent trip devices in the motor feeder breakers. The breakers can be operated from the CCR or from the local panel on the 15-foot elevation of the control building.

Each unit has two bistable flow switches for actuating low air flow alarms. One switch is installed just downstream of the absolute filter (and upstream of the fan), and the second is downstream of the charcoal filters. Two alarms on the SL safeguards panel in the CCR are associated with these switches, "Common Containment Recirculation Fan Normal Flow Path Low Flow," and "Common Containment Recirculation Fan Filter Flow Path Low Flow." The alarms are common to all five units and are normally out of service until a safeguards actuation signal arms them. Also, the safeguards panel SL has five individual lights labeled "CRF-21" through "CRF-25 Low Flow." These lamps show which unit is experiencing the trouble indicated by the two common alarms.

The air flow cooling coil assembly consists of 10 coil units mounted in two banks; each bank is five coils high. These banks are located one behind the other for horizontal series air flow, and the tubes of the coil are horizontal with vertical fins.

An air-to-water heat exchanger is connected to the fan motor to form an entirely enclosed cooling system. Air moves through the heat exchanger and is returned to the motor.

Both heat exchangers are supplied by the service water system. When the safeguards signal is actuated, two normally closed valves (TCV-1104 and TCV-1105) fully open and bypass service water flow around the normal temperature control valve (TCV-1103) on the common discharge line from the five units. Both of these valves fail open on loss of power and/or air, and either valve is capable of passing full flow. An open-close switch on the SB-1 safeguards panel in the CCR provides manual control of the two valves. Position indication lights from the limit switches on the valves are located above the controls. If flow is not sufficient for accident conditions, the alarm "CB Vent Fan Cooling Water Low Flow, 2,000" on safeguards panel SB-2 would annunciate. (This alarm is normally out of service until the safeguards actuation signal arms it.)

The condensate drainage from the moisture separators and cooling coils of both exchangers is collected from each unit, and directed to a vertical, 6-inch diameter, standpipe which is fitted with a notched weir. Using this instrument, the condensate flow rate of the water can be determined. After passing over the weir, the drains empty onto the containment floor directing the water to the containment sump, which has a small surface area and thus minimizes the amount of revaporization.

If the condensate drainage rate for all five units is nearly the same, it may be concluded that this water is condensate from the containment atmosphere. A particular unit with a high condensate drainage rate compared to the other units may be indicative of a leak in one of the cooling coils. The condensate drainage rate for each of the fan cooler units is indicated and alarmed in the control room.

Temperature and humidity detectors are located just upstream of each fan cooler unit. These elements provide information that is used to determine the dew point in containment. This information provides another indication of leakage from either the primary or secondary system into the containment.

1.5.2.3.6.2.4 Interfacing Systems. Under accident conditions, the fan cooler units interface with the following systems:

- Electric Power
- Service Water
- Safeguards Actuation System

Electric power is supplied from the following buses:

- Motor 21 Bus 5A
- Motor 22 Bus 5A
- Motor 23 Bus 2A
- Motor 24 Bus 3A
- Motor 25 Bus 6A

1.5.2.3.6.2.5 Technical Specifications. The reactor is not made critical unless all five fan cooler and charcoal filter units are entirely operable. During normal operation, fan cooler 21 or 22 may be out of service for a period not exceeding 7 days, or fan cooler 23, 24, or 25 may be out of service for a period not exceeding 24 hours, provided that both containment spray pumps are operable. This must be demonstrated daily. Fan cooler unit failures must be corrected within the specified periods or the reactor is placed in the hot shutdown condition using normal operating procedures. If the requirements are not satisfied within an additional 48 hours, the reactor is placed in the cold shutdown condition.

1.5.2.3.6.2.6 Test and Maintenance. Corrective maintenance is only performed on the units when a failure occurs. Periodic maintenance is performed on a fixed schedule. Surveillance tests are performed on the butterfly valves once during every refueling to verify their operability. These tests have no adverse effect on system availability.

Visual inspection of the filter installation is performed during every refueling, or any time when work on the filters could alter their integrity. The pressure drop across the moisture separators and HEPA filters is measured during each refueling. The HEPA filter banks are tested with locally generated dioctylphthalate particles test (DOP) during each refueling.

The iodine removal efficiency of at least one charcoal filter charcoal coupon (samples) from each unit is tested during every refueling. If the filter test fails, the charcoal in that unit is replaced.

1.5.2.3.6.2.7 Operator Interaction. Because the fan cooler units operate almost continuously in the normal mode and there is no testing except during the refueling outages, there is little chance for human error. During accident conditions, the fan coolers are automatically transferred to the accident mode. Operator action can compensate for failure of the automatic start system. There are enough indicators and alarms to immediately alert the operator that the units had not transferred to the accident mode and, therefore, would start the units manually. Consequently, a human error of this kind should be low.

1.5.2.3.6.2.8 Common Cause Effects. The operation of all five fan cooler units could conceivably be affected by an occurrence which simultaneously results in plugging the charcoal filter beds with airborne debris or plugging the cooling coil tubes with material entrained in the service water supply. These modes of failure are judged to be of little

significance and can be discounted when compared with system unavailability due to hardware and maintenance because of the rigid cleanliness requirements in containment and the straining of the service water source.

1.5.2.3.6.3 Logic Model.

1.5.2.3.6.3.1 Top Event. The following are the top undesired events for cooling and iodine removal and are derived from the primary functions of the system:

- Failure to circulate containment atmosphere and maintain containment pressure.

- Insufficient iodine removal by charcoal filters.

1.5.2.3.6.3.2 System Fault Tree. The fault trees used to analyze the accident operation of the containment fan cooling units are shown in Figure 1.5.2.3.6-4. Only hardware failure events are modeled; other causes are accounted for in the quantitative analysis Section 1.5.2.3.6.4. Electrical power is shown as a "house" event. System operation is assumed to be initiated by a safety injection signal. No manual actuation is accounted for in this analysis. The removal of iodine by the charcoal filters is not modeled in the fault tree or quantified. Section 1.3 discusses the reasons for not including these actions in the analysis. In this scenario, any previously operating fan cooler units are stopped and then all five coolers are restarted in a programmed time sequence. Table 1.5.2.3.6-1 outlines the coding used in the system fault tree.

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1.5.2.3.6.4 Quantification.

1.5.2.3.6.4.1 Random Hardware Failures. Hardware failures in the fan cooling system can be attributed to either a failure in the fan cooling unit or an interruption of the service water supply to one of the heat exchangers in the cooling unit. Figure 1.5.2.3.6-5 outlines the components that must function to yield system success. For supercomponent A to function, three of the five cooling units must operate. For successful operation, the cooling unit must start, shift to the accident mode, and operate with service water flow maintained to both of the integral coolers for a period of 24 hours. For supercomponent B to function, one of the two temperature control valve bypass valves in the common service water discharge from the five cooling units must open and remain open for 24 hours. The SI actuation signal is needed to initiate fan cooler operation and shift the air flow butterfly valves and service water valves. Electric power is needed for fan operation. Both are modeled as house events.

The train unavailability of a cooler (Q_{HC}) because of hardware is identical for each fan cooling unit.

Component	Failure Mode	Quantity	Mean Failure (Q)/d from Table 1.5.2.3.6-1
Fan Cooler	Fails to start on demand	1	7.26×10^{-4}/demand
Fan Cooler	Fails to run	1	4.08×10^{-5}/hour
Iso MOVs	Transfers closed	6	7.40×10^{-8}/hour
Manual Valve	Transfers closed	1	7.40×10^{-8}/hour
Heat Exchangers	Rupture	2	8.42×10^{-7}/hour

$$Q_{HC} = Q_{C_{start}} + \left(1 - Q_{C_{start}}\right)\left(24 \text{ hours}\right)\left(Q_{C_{run}} + 7Q_V + 2Q_{HE}\right)$$

This expression represents the hardware unavailability of a single fan cooling unit and results in an unavailability of:

Mean: 1.75×10^{-3}

Variance: 1.73×10^{-6}

The unavailability of supercomponent B because of hardware is the square of the failure rates for each of the air-operated bypass valves failing to open on demand:

$$Q_{HB} = (7.49 \times 10^{-4})^2$$

This yields:

Mean: 9.45×10^{-7}

Variance: 6.55×10^{-12}

The unavailability of supercomponent A because of hardware failure (three or more fan cooler units fail), with all electric power available, is the sum of the unavailabilities for the 16 possible combinations in which three or more fan coolers are inoperative:

$$Q_H(\text{supercomponent A}) = 10(Q_{HC})^3 + 5(Q_{HC})^4 + Q_{HC}^5$$

For the various states of electric power considered, the calculation is altered in that a reduced number of hardware failures are required to fail supercomponent A.

With power unavailable at bus 6A, the expression for the hardware unavailability of supercomponent A becomes:

$$Q_{HA} = 6(Q_{HC})^2 + 4(Q_{HC})^3 + 1(Q_{HC})^4$$

With power unavailable to either 2A and 3A or 5A, supercomponent A is reduced to three cooler units and any single failure will cause failure of the system. In this case, the hardware unavailability of supercomponent A is:

$$Q_{HA} = 3(Q_{HC})$$

The unavailability of supercomponent B is not affected by the electric power state and total system unavailability from hardware failure (Q_H system) for each electric power state and is the sum of those determined for supercomponents A and B. The results are contained in Table 1.5.2.3.6-2.

1.5.2.3.6.4.2 Test. Whenever the plant is operating, the fan cooler units are in operation in their normal mode. Testing is done during refueling outages. Therefore, testing has no impact on system unavailability.

1.5.2.3.6.4.3 Maintenance. Indian Point 2 maintenance experience yields a fan cooler unit unavailability (Q_{CM}) of:

Mean: 1.37×10^{-3}

Variance: 1.35×10^{-7}

Maintenance can only be performed on one fan cooler at a time during normal operation without necessitating a unit shutdown. With electric power available to all buses and system unavailability because of maintenance (Q_{SM}) results when two additional fan cooling units become

inoperative as a result of hardware failures. This situation is represented by:

$$Q_{SM} = 5Q_{CM}\left(6(Q_{HC})^2 + 4(Q_{HC})^3 + (Q_{HC})^4\right)$$

With electric power unavailable to one cooling unit (failure of bus 6A), system unavailability because of maintenance becomes:

$$Q_{SM} = 4Q_{CM}\left(3Q_{HC} + 3(Q_{HC})^2 + (Q_{HC})^3\right)$$

Failure of electric power to two cooler units (failure of bus 5A or 2A 3A) results in a system unavailability because of maintenance of:

$$Q_{SM} = 3Q_{CM} + 6Q_{CM}(Q_{HC}) + 3Q_{CM}(Q_{HC})^2$$

A summary of the maintenance unavailabilities for each of the electric power states is contained in Table 1.5.2.3.6-2.

1.5.2.3.6.4.4 Human Factors. Because the fan cooler units operate almost continuously in the normal mode, and there is no testing except during refueling outages, there is little chance for human error. During accident conditions, the fan cooler motors are automatically sequenced onto their safeguards buses, and the fan cooler charcoal butterfly valves and service water discharge butterfly valves are automatically switched to their accident position. Failure of the automatic start system can be compensated for by operator action. There are sufficient indicators and alarms so that the operator would be immediately aware that the units had not started properly or the valves had not switched to their accident position, and he would start the units or open the valves manually. Because the operator interacts with the system only when there is no automatic actuation, operator actions decrease system unavailability. Therefore, the effects of human interaction may be conservatively excluded.

1.5.2.3.6.4.5 Common Cause. The operation of all five fan cooler units could conceivably be affected by an occurrence which simultaneously results in plugging of charcoal filter beds with airborne debris or plugging the cooling coil tubes with material entrained in the service water supply. These modes of failure are judged to be of little significance and can be discounted when compared with system unavailability due to hardware and maintenance because of the rigid cleanliness requirements in containment and the straining of the service water supply together with the fact that the system is always in service.

1.5.2.3.6.4.6 Statistical Summary. Overall system unavailability is the sum of the contributions from hardware (Q_{H}system), maintenance (Q_{SM}) and common cause (Q_{CC}) for each of the states of electric power analyzed. A summary of these calculations is contained in Table 1.5.2.3.6-2.

TABLE 1.5.2.3.6-1

INDIAN POINT 2 SYSTEMS COMPONENTS

Component and Fault Tree Code	Failure Mode	Normal Position	Failure Rate		Data Source Table 1.5.1-4 Item Number
			Mean	Variance	
Service Water Valves					
TSW1104Q	Failure to open	Closed	7.49×10^{-4}	4.01×10^{-7}	8
TSW1105Q	Failure to open	Closed	7.49×10^{-4}	4.01×10^{-7}	
TSW44βA	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	1
TSW44βB	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW44βC	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW41βA	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW41βB	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW71βA	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW71βB	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
Heat Exchangers					
KHECL	Rupture or gross leakage	Passive	8.42×10^{-7}	1.94×10^{-12}	24
KHEML	Rupture or gross leakage	Passive	8.42×10^{-7}	1.94×10^{-12}	
Fan Cooler Unit					
KBL3NN	Motor fails to start		7.26×10^{-4}	1.82×10^{-6}	22
KBL3NS	Unit fails to operate in accident mode		4.08×10^{-5}	3.60×10^{-10}	23

*MOVs are deenergized open during normal reactor operation.

inoperative as a result of hardware failures. This situation is represented by:

$$Q_{SM} = 5Q_{CM}\left(6(Q_{HC})^2 + 4(Q_{HC})^3 + (Q_{HC})^4\right)$$

With electric power unavailable to one cooling unit (failure of bus 6A), system unavailability because of maintenance becomes:

$$Q_{SM} = 4Q_{CM}\left(3Q_{HC} + 3(Q_{HC})^2 + (Q_{HC})^3\right)$$

Failure of electric power to two cooler units (failure of bus 5A or 2A 3A) results in a system unavailability because of maintenance of:

$$Q_{SM} = 3Q_{CM} + 6Q_{CM}\,(Q_{HC}) + 3Q_{CM}\,(Q_{HC})^2$$

A summary of the maintenance unavailabilities for each of the electric power states is contained in Table 1.5.2.3.6-2.

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TSW1105Q	Failure to open	Closed	7.49×10^{-4}	4.01×10^{-7}	
TSW44βA	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	1
TSW44βB	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW44βC	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW41βA	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW41βB	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW71βA	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
TSW71βB	Transfers closed	Open*	7.40×10^{-8}	5.89×10^{-15}	
Heat Exchangers					
KHECL	Rupture or gross leakage	Passive	8.42×10^{-7}	1.94×10^{-12}	24
KHEML	Rupture or gross leakage	Passive	8.42×10^{-7}	1.94×10^{-12}	
Fan Cooler Unit					
KBL3NN	Motor fails to start		7.26×10^{-4}	1.82×10^{-6}	22
KBL3NS	Unit fails to operate in accident mode		4.08×10^{-5}	3.60×10^{-10}	23

*MOVs are deenergized open during normal reactor operation.

TABLE 1.5.2.3.6-2

INDIAN POINT 2 STATISTICAL SUMMARY

Unavailability Contribution	Power State		
	All Power Available	6A Unavailable	(2A, 3A) or 5A Unavailable
Supercomponent A Hardware Failure (Q_{HA})			
Mean	2.70×10^{-7}	2.90×10^{-5}	5.30×10^{-3}
Variance	1.00×10^{-11}	1.10×10^{-8}	1.60×10^{-5}
Supercomponent B Hardware Failure (Q_{HB})			
Mean	9.45×10^{-7}	9.45×10^{-7}	9.45×10^{-7}
Variance	6.55×10^{-12}	6.55×10^{-12}	6.55×10^{-12}
System Hardware ($Q_{H\ system}$)			
Mean	1.20×10^{-6}	3.00×10^{-5}	5.30×10^{-3}
Variance	1.50×10^{-11}	1.10×10^{-8}	1.50×10^{-5}
System (Q_{SM})			
Mean	2.00×10^{-7}	2.90×10^{-5}	1.50×10^{-2}
Variance	5.20×10^{-13}	5.50×10^{-10}	6.30×10^{-5}
Total System (Q_{system})			
Mean	1.40×10^{-6}	5.90×10^{-5}	2.03×10^{-2}
Variance	1.60×10^{-11}	1.10×10^{-8}	7.70×10^{-5}
5th Percentile	1.10×10^{-7}	1.70×10^{-5}	1.10×10^{-2}
Median	5.30×10^{-7}	3.80×10^{-5}	1.70×10^{-2}
95th Percentile	3.60×10^{-6}	1.10×10^{-4}	3.10×10^{-2}

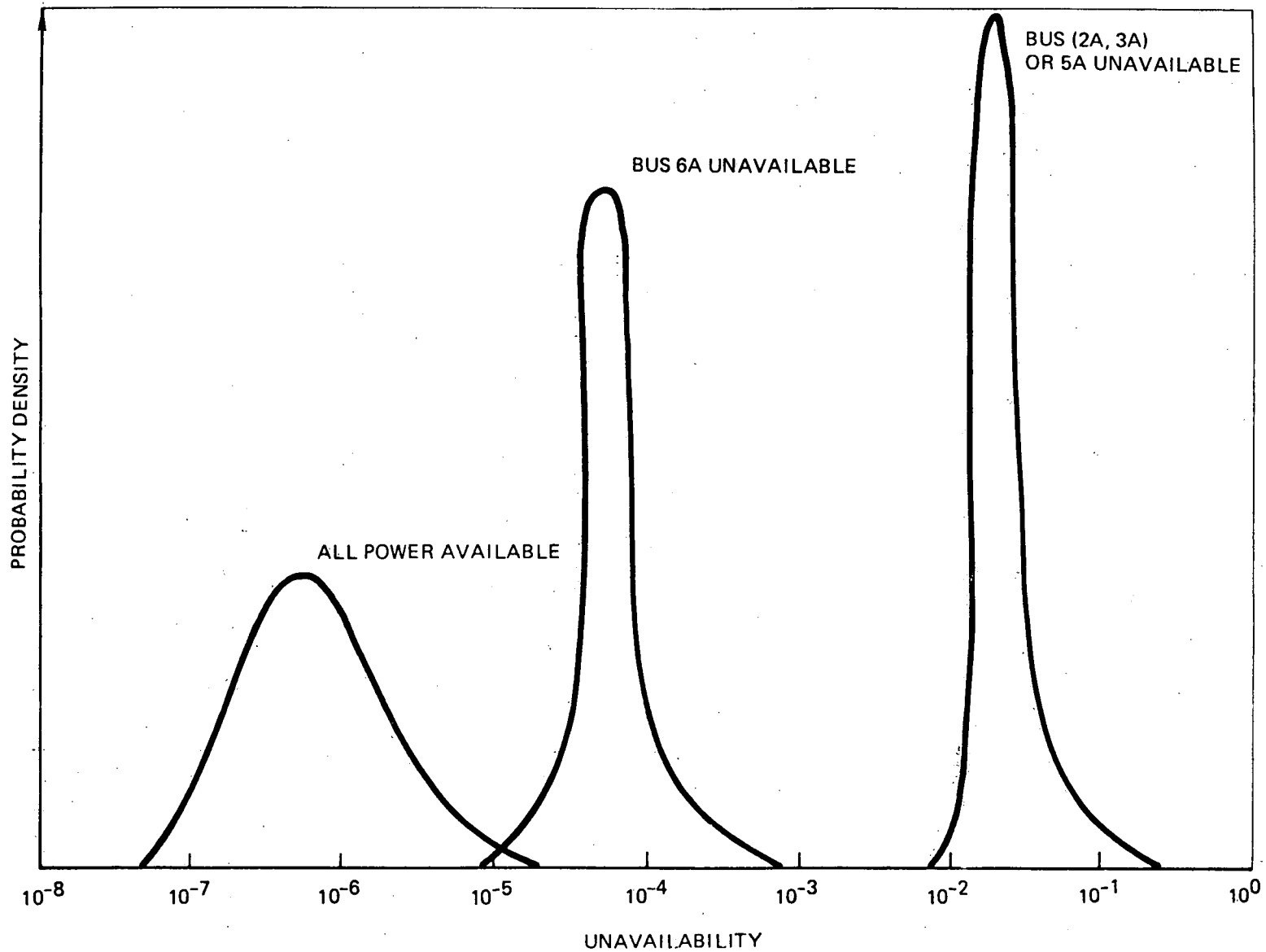

Figure 1.5.2.3.6-1. Indian Point 2 Probability Distribution of Containment Fan Cooling System Unavailability

TABLE 1.5.2.3.6-2

INDIAN POINT 2 STATISTICAL SUMMARY

Unavailability Contribution	Power State		
	All Power Available	6A Unavailable	(2A, 3A) or 5A Unavailable
Supercomponent A Hardware Failure (Q_{HA})			
Mean	2.70×10^{-7}	2.90×10^{-5}	5.30×10^{-3}
Variance	1.00×10^{-11}	1.10×10^{-8}	1.60×10^{-5}
Supercomponent B Hardware Failure (Q_{HB})			
Mean	9.45×10^{-7}	9.45×10^{-7}	9.45×10^{-7}
Variance	6.55×10^{-12}	6.55×10^{-12}	6.55×10^{-12}
System Hardware ($Q_{H\ system}$)			
Mean	1.20×10^{-6}	3.00×10^{-5}	5.30×10^{-3}
Variance	1.50×10^{-11}	1.10×10^{-8}	1.50×10^{-5}
System (Q_{SM})			
Mean	2.00×10^{-7}	2.90×10^{-5}	1.50×10^{-2}
Variance	5.20×10^{-13}	5.50×10^{-10}	6.30×10^{-5}
Total System (Q_{system})			
Mean	1.40×10^{-6}	5.90×10^{-5}	2.03×10^{-2}
Variance	1.60×10^{-11}	1.10×10^{-8}	7.70×10^{-5}
5th Percentile	1.10×10^{-7}	1.70×10^{-5}	1.10×10^{-2}
Median	5.30×10^{-7}	3.80×10^{-5}	1.70×10^{-2}
95th Percentile	3.60×10^{-6}	1.10×10^{-4}	3.10×10^{-2}

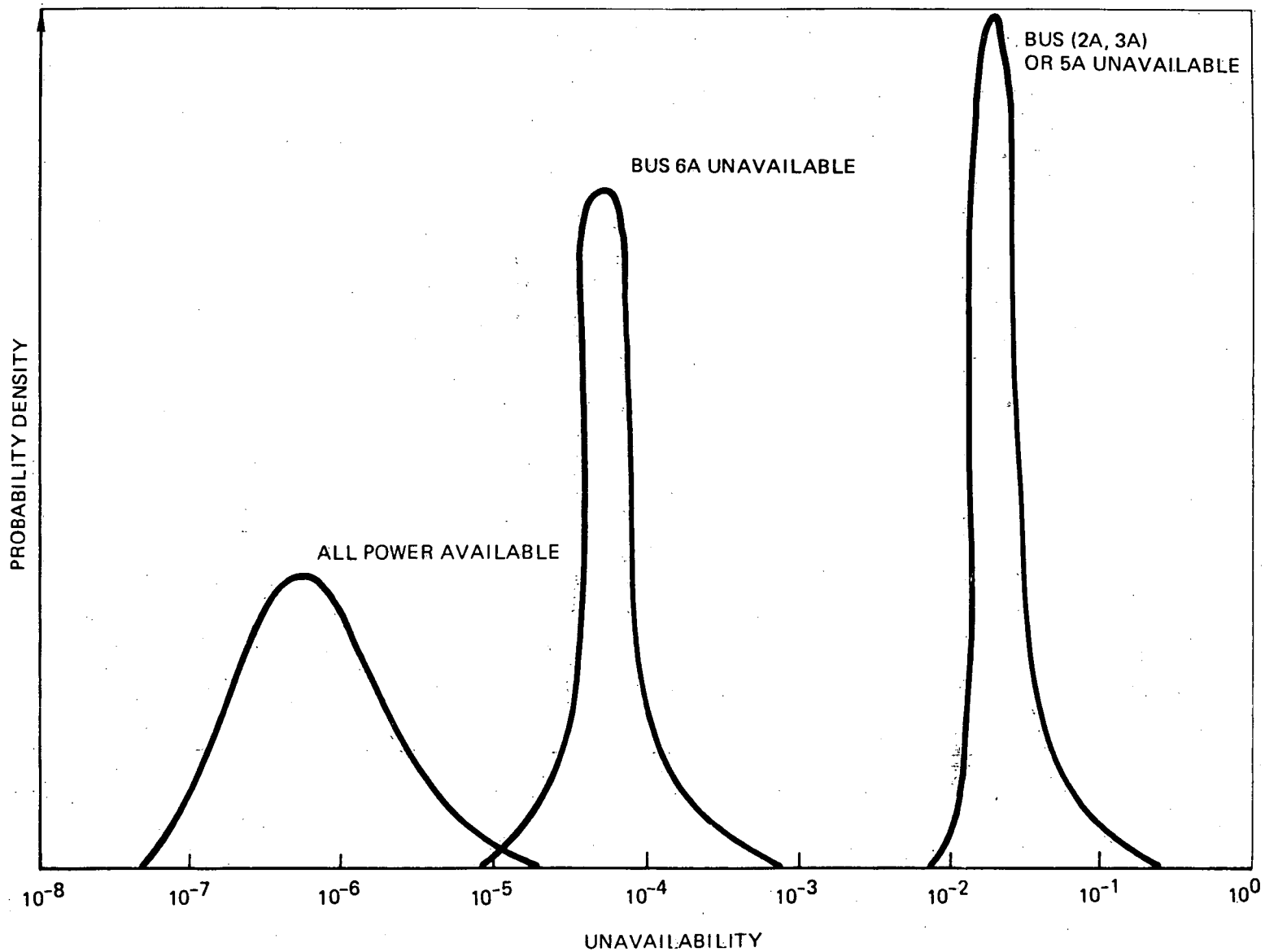

Figure 1.5.2.3.6-1. Indian Point 2 Probability Distribution of Containment Fan Cooling System Unavailability

UNIT	A	B	C
21	21-1	21-2	21-3
22	22-4	22-5	22-6
23	23-7	23-8	23-9
24	24-10	24-11	24-12
25	25-13	25-14	24-15

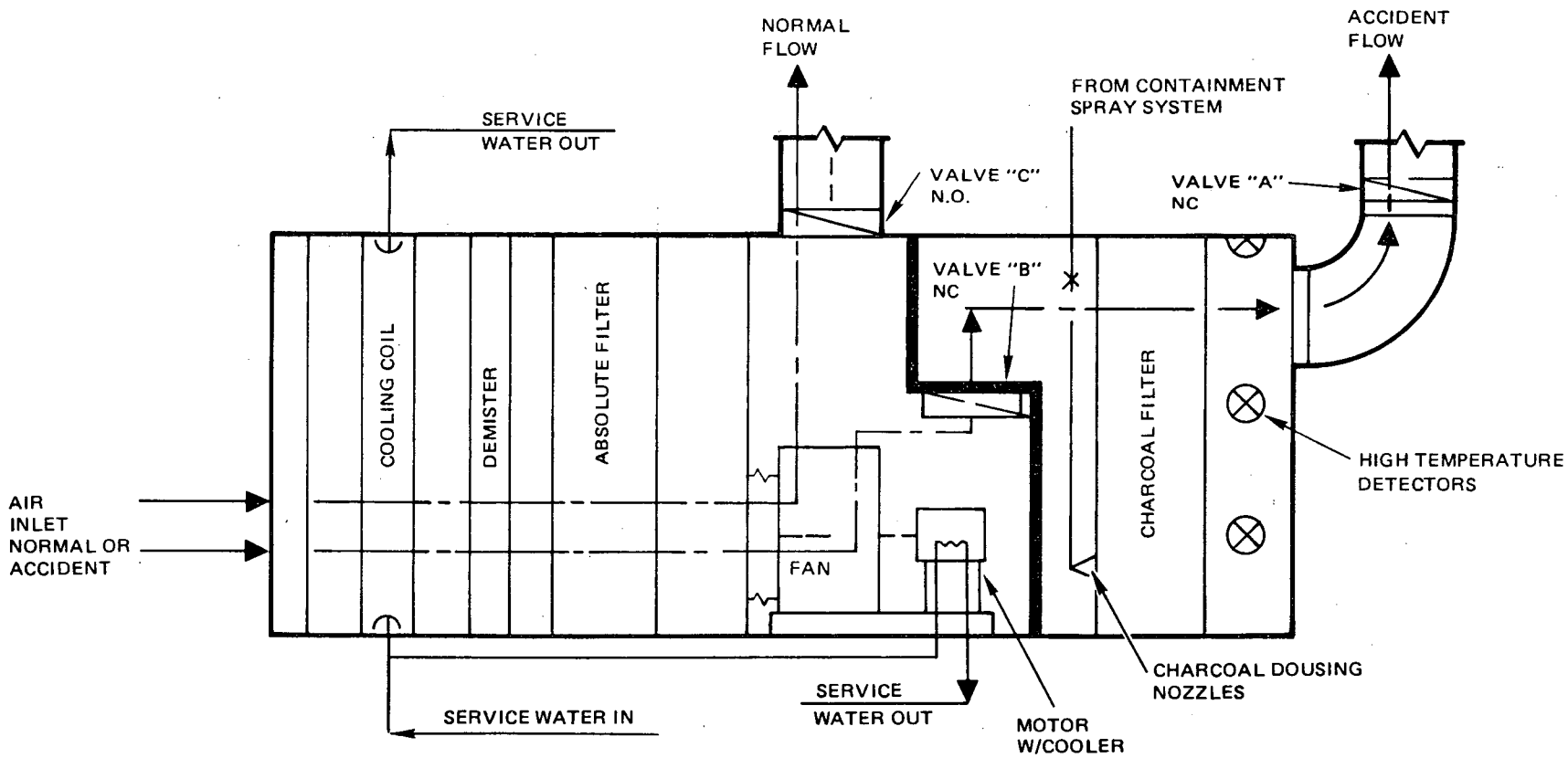

Figure 1.5.2.3.6-2. Indian Point 2 Fan Cooler Unit

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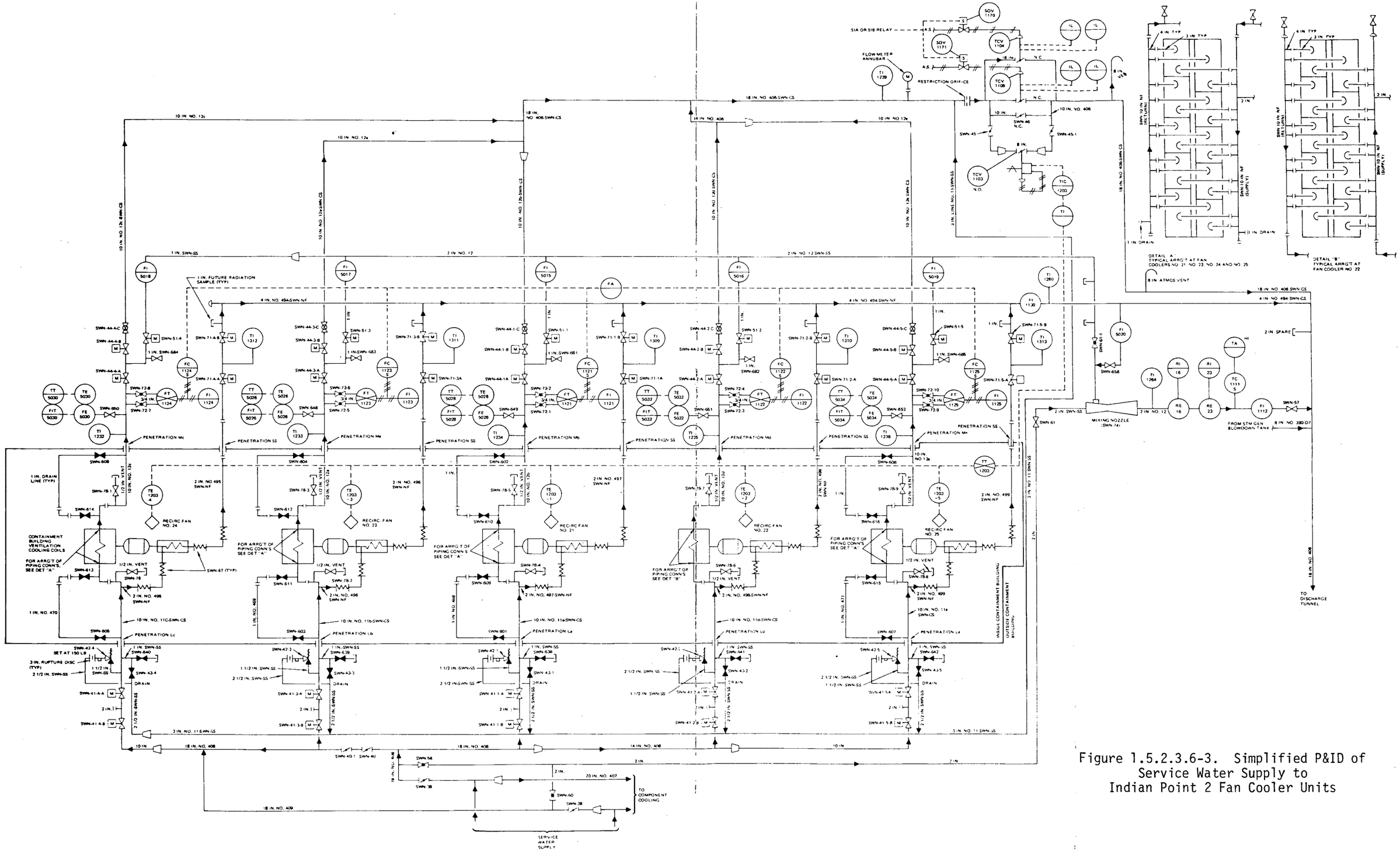


Figure 1.5.2.3.6-3. Simplified P&ID of Service Water Supply to Indian Point 2 Fan Cooler Units

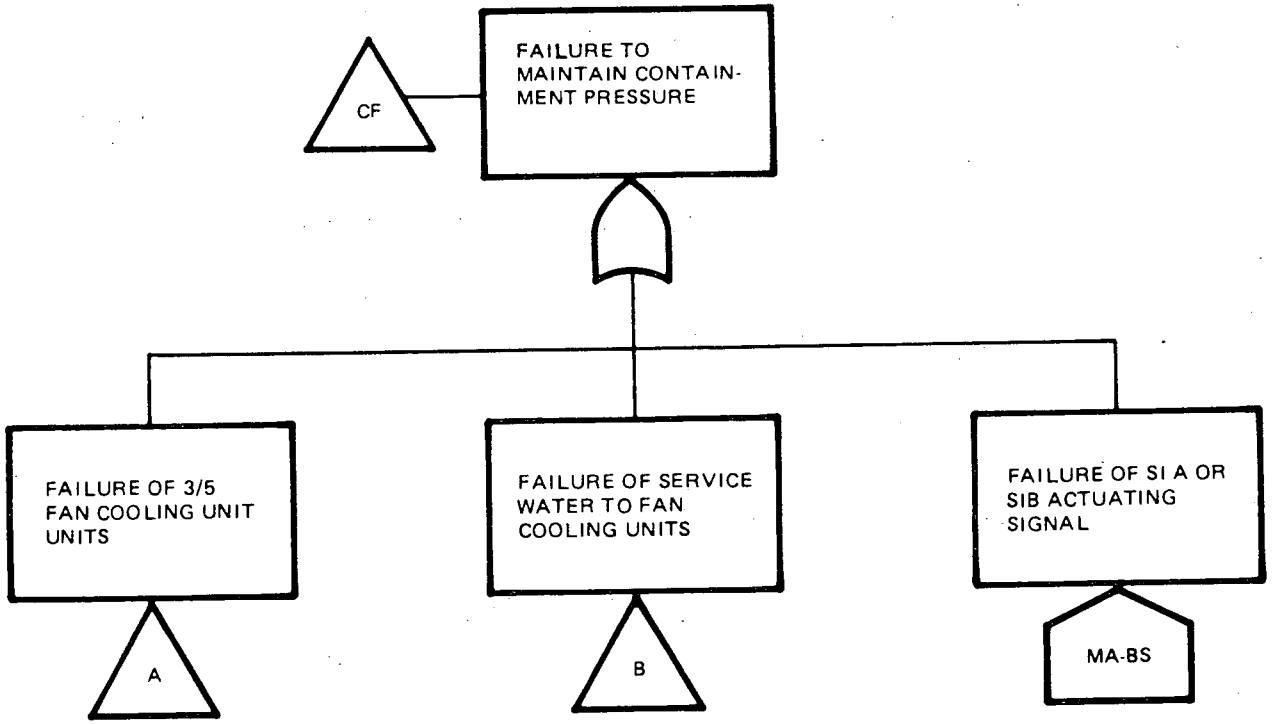


Figure 1.5.2.3.6-4. Indian Point 2 Fault Tree of Fan Cooler System (Sheet 1 of 4)

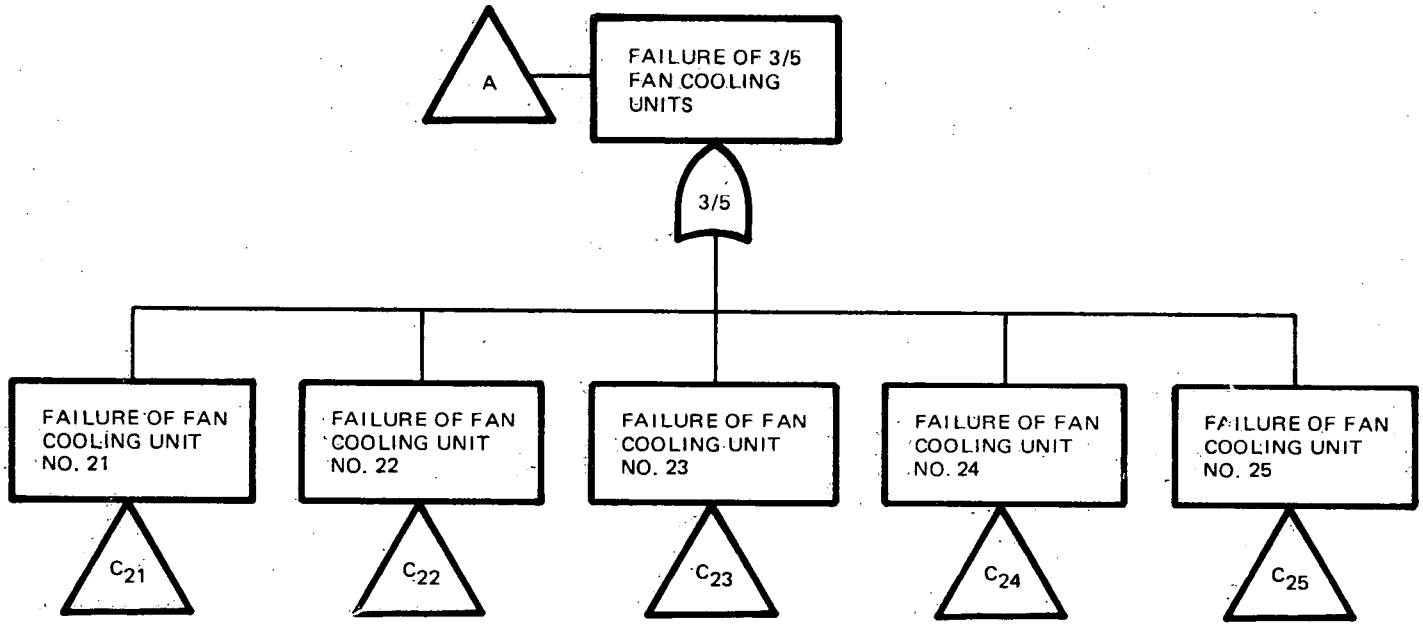


Figure 1.5.2.3.6-4. (Sheet 2 of 4)

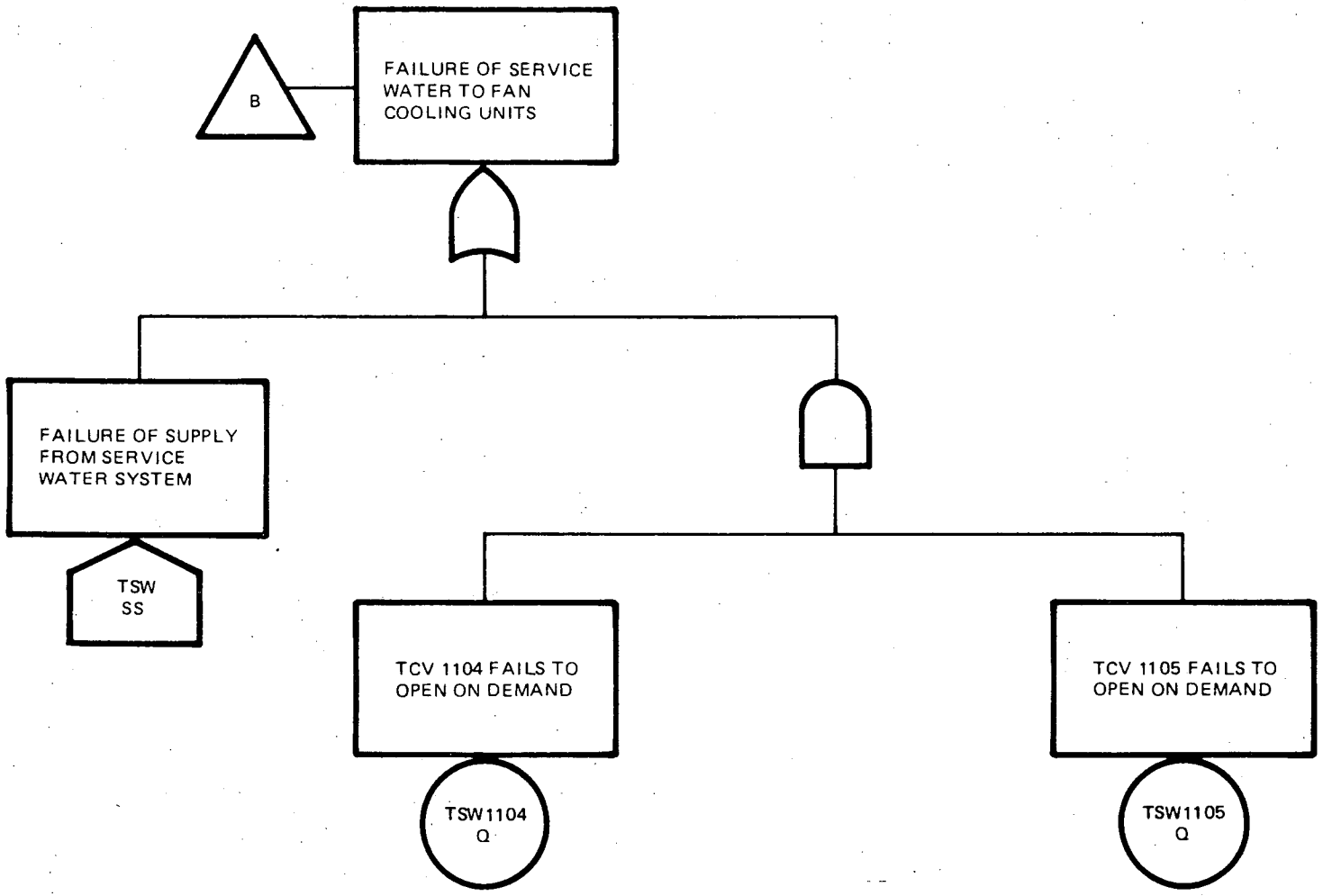
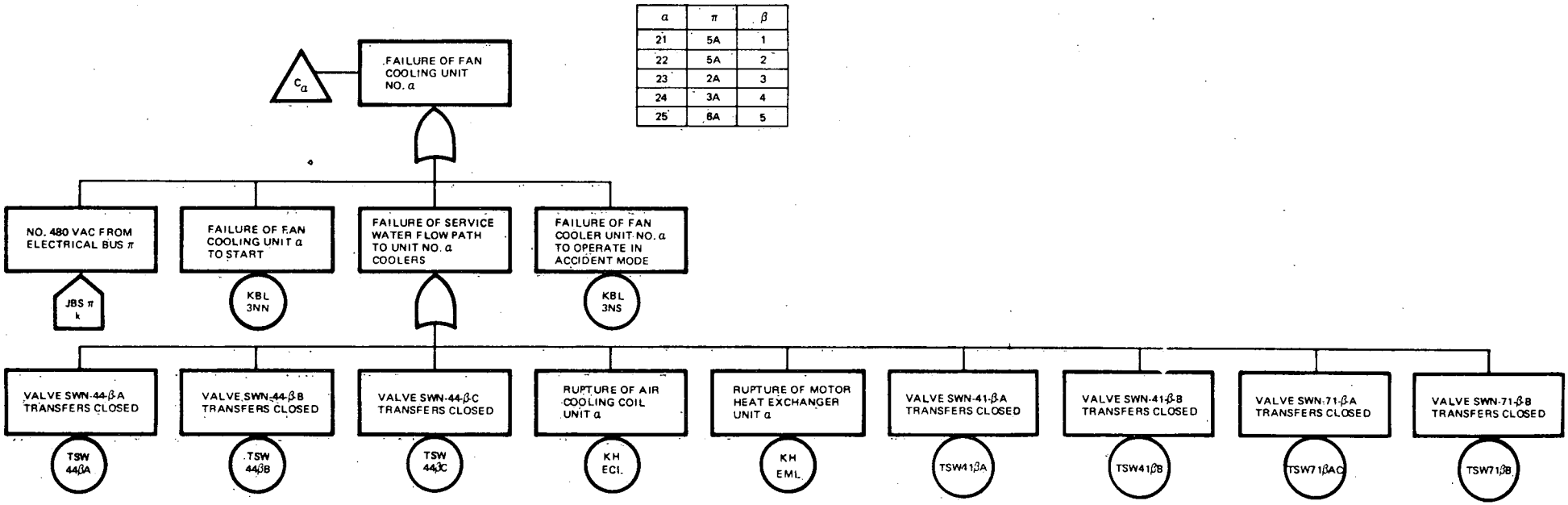


Figure 1.5.2.3.6-4. (Sheet 3 of 4)



α	π	β
21	5A	1
22	5A	2
23	2A	3
24	3A	4
25	8A	5

Figure 1.5.2.3.6-4. (Sheet 4 of 4)

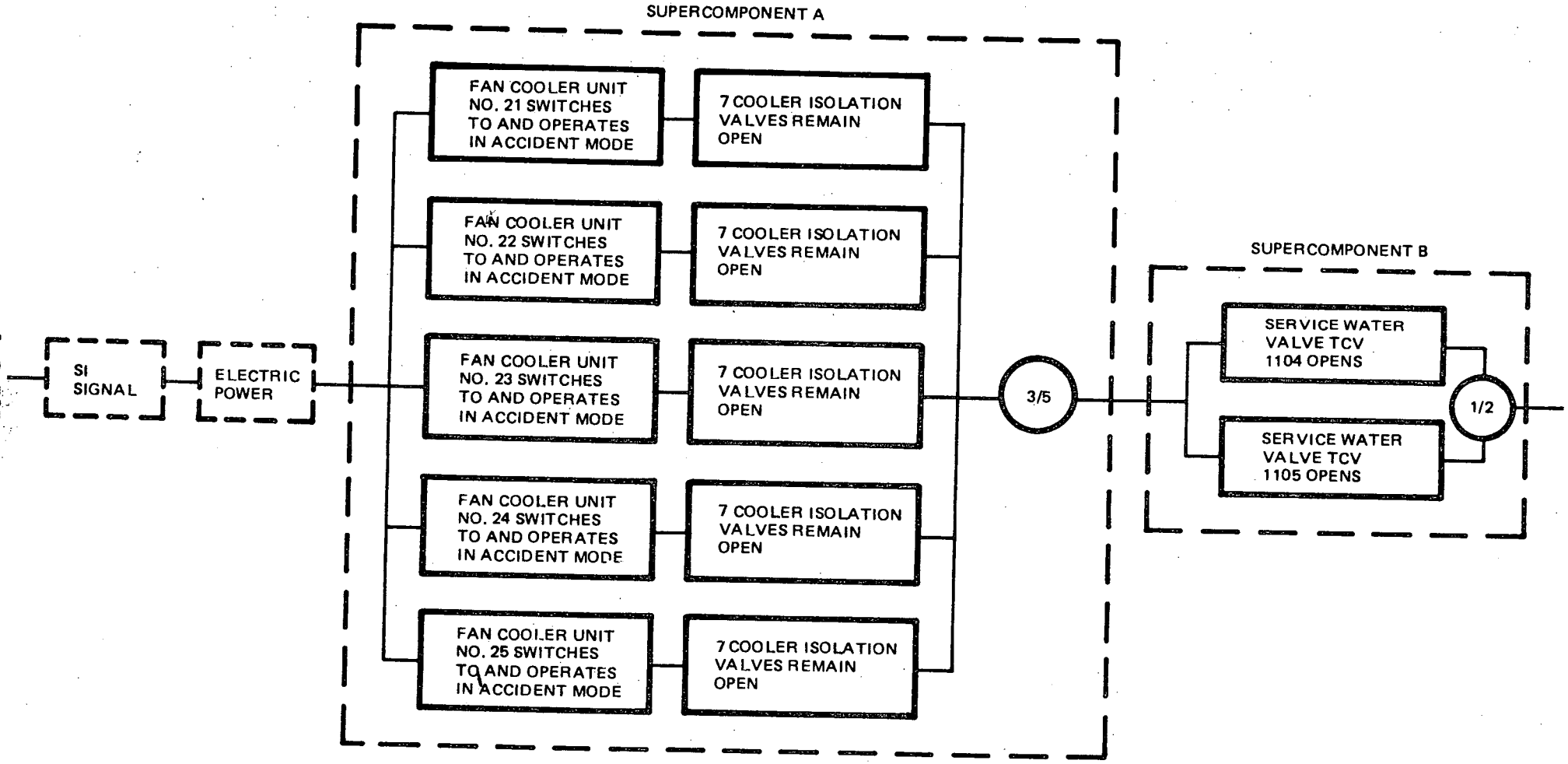


Figure 1.5.2.3.6-5. Indian Point 2 Fan Cooler System Block Diagram

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1.5.2.3.7 Indian Point 2 Component Cooling System

1.5.2.3.7.1 Summary.

1.5.2.3.7.1.1 Introduction. The component cooling system (CCS) is evaluated for its ability to supply water for heat removal during the recirculation phase of all LOCAs and all transient events. The primary functions of the system following an accident are to remove residual and sensible heat from residual heat removal (RHR) heat exchangers, RHR pumps, safety injection (SI) pumps, charging pumps, and to supply water to the auxiliary component cooling pumps for recirculation pump cooling.

The analysis is carried out under the following conditions:

- The system was operating in the normal mode of cooling prior to the LOCA or transient. This is further defined as two of three pumps and both heat exchangers operating prior to the initiating event.
- No operator actions to recover the system following failure or to correct deficiencies in the system are considered in this analysis.
- System success is defined as one of three pumps starting and operating for 24 hours, and one heat exchanger continuing to operate for 24 hours.

1.5.2.3.7.1.2 Results. Table 1.5.2.3.7-1 summarizes the results of the CCS analysis. Three boundary conditions for electric power are analyzed: power at all 480V buses; loss of power at a single bus; and loss of power at two 480V buses.

The analysis revealed the following dominant contributors to failure of the CCS to supply a sufficient amount of cooled water for 24 hours:

	Mean
• Power at all 480V buses	1.0×10^{-5}
- Passive valve failure (service water supply) (55%)	5.7×10^{-6}
- Pump train failure (44%)	4.6×10^{-6}
• Power at two 480V buses (loss of a single 480V bus)	6.1×10^{-4}
- Failure of the two operable pump trains (99%)	6.1×10^{-4}
• Power at one 480V bus	6.5×10^{-3}
- Failure of the operable pump train (99.9%)	6.5×10^{-3}

No comparison is made to Reactor Safety Study (RSS) results as there is no comparable system analysis in the RSS.

1.5.2.3.7.1.3 Conclusions. The component cooling system is required to support plant operations and will be operating at the time of the initiating event. For this reason, this system is unusual when compared to the plant standby emergency systems in that the dominant contributors to system failure with power available to all pumps are passive valve and pipe failures. Probability distributions of system unavailability for the states of electric power considered are shown in Figure 1.5.2.3.7-1.

1.5.2.3.7.2 System Description.

1.5.2.3.7.2.1 System Function. The CCS loop is one of three subsystems of the auxiliary coolant system (ACS) at Indian Point 2. It is a closed loop cooling system which is designed to remove residual and sensible heat from various primary plant components during power and shutdown operations, and under accident and transient conditions. The system also provides a barrier between the primary plant and the environment to prevent radioactive releases to the environment.

A block diagram and a simplified system piping arrangement are shown in Figures 1.5.2.3.7-2 and 1.5.2.3.7-3, respectively. Success of the system is defined as one of three CCS pumps operating initially, followed by a second pump as power is available and one of two CCS heat exchangers operating to supply postaccident cooling.

1.5.2.3.7.2.2 Basic Description. The CCS loop consists of three pumps, two heat exchangers which are cooled by service water, a single surge tank, and the necessary piping and valves to supply the various cooled equipment. Table 1.5.2.3.7-2 shows the normal and emergency flows required of the CCS and the number of pumps and heat exchangers required to develop this flow for various plant conditions.

The CCS pumps are horizontal, centrifugal pumps rated at 3,600 gpm at 150 psi. During normal plant operation, two of the three pumps are required to supply the necessary flow for plant cooling loads. During accident conditions, one of the three pumps is required at the start of the recirculation phase to supply the necessary flow for the plant emergency cooling loads. A second pump is started when power becomes available.

The three CCS pumps are always lined up to the common discharge header and the return header. During normal plant operation, low discharge pressure (which indicates insufficient capacity) is annunciated on the ACS panel and starts the third CCS pump.

Each CCS pump requires a minimum flow of 500 gpm for the removal of pump heat. Low flow in the CCS supply header of 1,500 gpm is alarmed in the control room at the ACS panel.

The CCS pumps are supplied from the following 480V switchgear buses:

- Pump 21 Bus 5A
- Pump 22 Bus 2A
- Pump 23 Bus 3A

Each of these 480V switchgear buses is supplied by the emergency diesel generators (EDGs).

The CCS surge tank is located in the primary auxiliary building and has a normal working volume of 1,000 gallons. The surge tank accommodates changes in operating volume of the CCS due to changes in operating

temperature. The free volume of this tank is sufficient to accommodate the in-leakage from a rupture of a reactor coolant pump thermal barrier cooling coil for 3 minutes. Tank makeup is provided by the flash evaporator through a manual valve to accommodate losses of system mass. The surge tank is normally vented to atmosphere; however, high radiation detected at the CCS return header causes automatic closing of the vent valve. The high radiation condition is alarmed in the control room. A relief valve on the surge tank discharges to the waste holdup tank to provide pressure relief when the normal vent is closed. Surge tank level is indicated and alarmed in the control room.

The two CCS heat exchangers are shell and tube type heat exchangers which are cooled by the service water system. The heat exchangers are designed to remove 3.14×10^7 Btu/hour at a shell side ΔT of 12^oF with 5,320 gpm CCS flow and a tube side ΔT of 7^oF with 9,100 gpm service water flow. During normal plant operation, both heat exchangers will be in operation. During accident conditions, the heat exchanger lineup is not required to be changed; however, only one heat exchanger is required for heat removal. The heat exchanger outlet temperature and header return temperature are monitored and alarmed in the control room.

The CCS is basically a single supply header to the residual heat removal (RHR) heat exchangers and a single return header to the CCS pumps and heat exchangers. The necessary cooling lines are branched off of these main supply and return headers. Most of the components cooled by the CCS receive flow during all plant conditions. The following are exceptions:

- Reactor Coolant Pump Cooling. Two series, motor-operated, isolation valves are provided for the reactor coolant pump supply line, the reactor coolant pump motor cooling return line, and the thermal barrier return line. These valves are automatically closed upon receipt of a containment isolation phase B signal. Each valve in a single line receives power from a separate 480V MCC (either 26A or 26B) which, in turn, receives power from a separate vital switchgear bus. FCV-625 in the return line from the reactor coolant pump thermal barriers also closes on a high flow condition in this return line. This high flow condition is indicative of a thermal barrier cooling coil failure. Closure of FCV-625 limits the amount of in-leakage from this failure.

- Excess Letdown Heat Exchanger Cooling. The supply line to this heat exchanger contains two series, air-operated, normally open valves. These valves are designed to fail closed on loss of power or loss of air. These valves receive a containment isolation phase A automatic close signal. The return line from this heat exchanger contains two series, air-operated valves. One of the valves is normally closed. In all other respects, the operation of these valves is the same as the supply valves.

- RHR Heat Exchanger Cooling. Each RHR heat exchanger has a normally closed motor-operated valve located in its CCS outlet line. These valves receive an automatic open signal from the safeguards actuation system.

The three safety injection pumps receive CCS flow during all plant conditions. Each pump drives an attached circulating pump which supplies the cooling requirements for the safety injection pump using the water contained in the CCS supply and return headers. The CCS outlets of the three safety injection pumps combine into a single return line. The flow through this line is monitored and alarmed in the control room. Emergency supplies to these pumps are available from the primary water system or through a 2-inch emergency city water connection.

The two RHR pumps also receive CCS during all plant conditions. Flow from these pumps is indicated locally and alarmed in the control room (low flow). Emergency supplies to these pumps are available from the primary water system or through a 2-inch emergency city water connection.

Two auxiliary component cooling pumps are used to supply component cooling water to the engineered safeguards system recirculation pumps. These pumps are included in the low pressure recirculation system analysis and, therefore, are excluded from this analysis.

1.5.2.3.7.2.3 System Operation During Emergency Conditions. As stated previously, two of three CCS pumps and both CCS heat exchangers will be in operation to support plant power operation. The following paragraphs discuss the response of this system to various emergency conditions.

- Unit Trip, No Blackout and No Safety Injection. When the unit trips and no blackout or safety injection occurs, the system will remain in operation as it was before the event since all power requirements will have transferred from the unit auxiliary transformer to the station auxiliary transformer.

- Unit Trip, With Blackout and No Safety Injection. When this condition occurs, all CCS pumps are tripped. Electrical power is reestablished using the EDGs. CCS pumps are automatically started by this event as a function of energized (live) 480V buses.

  The CCS pump is started to protect the reactor coolant pump's (RCP) lower radial bearing and seal package, since the charging pumps will have tripped and RCP seal and bearing water will be derived from hot reactor coolant system (RCS) water. The CCS will cool this hot RCS water as it passes by the thermal barrier heat exchanger.

- Unit Trip, With Blackout and With Safety Injection. When this condition occurs, all CCS pumps are tripped. Electrical power is reestablished using the EDGs. The following events will occur in the component cooling loop:

  - Valves 822A and 822B (residual heat exchangers) are opened.

  - The auxiliary component cooling pumps are started to protect the motors of the safety injection system recirculation pumps from the containment accident atmosphere.

  - The shaft-driven circulating pumps will be running when the safety injection pumps run and will supply cooling services for these pumps.

These events occur automatically as a result of the engineered safeguards sequence signal. When the injection phase is completed and the recirculation phase is entered into, two CCS pumps or one CCS pump are started by recirculation phase switches RS-2 and RS-5. RS-2 will start one pump; RS-5 will start the other pump if all four 480V buses are energized and a second service water pump is running. Positioning RS-2 to the "On" position will start pump 23; if it failed to start, pump 22 would be started; and if pump 22 failed to start, pump 21 would be started. This action is independent of the supporting service water system (SWS) pumps. Positioning switch RS-5 to "On" will (providing power is available and two of the selected recirculation phase service water pumps are running) start pump 22. If pump 22 fails to start or is running, pump 21 is started.

- Unit Trip, No Blackout With Safety Injection. If there is a safety injection signal and the unit trips with no blackout, the CCS pumps will be started as part of the safeguards sequence signal.

1.5.2.3.7.2.4 Support Systems. Successful operation of the CCS requires operation of the SWS and the electric power system. All three CCS pumps receive power from 480V switchgear buses supplied by the EDGs. Both CCS heat exchangers receive service water from the conventional service water header.

1.5.2.3.7.2.5 Instrumentation and Controls. The plant operator controls the CCS pumps from the ACS panel in the control room.

The control switch for each pump breaker is located at the ACS panel; status light indications are above each switch. As each pump breaker control circuit is identical, only the circuit for pump 21 will be discussed.

The control switch has four positions (spring-return to Auto).

1. Pull-Out. The pump is disabled from starting by any automatic start signal. With the switch in this position, the "Safeguards Equipment Locked Open" alarm will be annunciated on the safeguards panel in the control room.

2. Stop. The pump breaker is tripped open.

3. Auto. The pump will be started for any one of the following conditions:

   a. Low discharge header pressure during normal operation.

   b. Timed start on a "Unit Trip with Blackout or No SI" condition.

   c. Timed start on "SI and No Blackout" condition.

d. Automatic start during SI and blackout when shifting from the injection phase to the recirculation phase. The operator must make the switchover. Automatic starting is a result of recirculation phase switches RS-2 and RS-5 being turned to "On" by the operator.

4. Start. The pump will be started. While the pump is running, it can be tripped by:

   a. Placing the control switch to the stop or pull-out position.
   b. Undervoltage on the associated 480V switchgear bus.
   c. Blackout and SI conditions.
   d. Overload.

All motor-operated or air-operated valves used for containment isolation are operated from the containment isolation panel in the control room. The RHR heat exchanger outlet motor-operated valves are operated from the ACS panel in the control room.

Automatic operation of the CCS in response to emergency conditions has been discussed in the preceding paragraphs. The standby CCS pump will also start automatically in response to a low header pressure.

During system operation, header pressure, supply and return temperature, header flow, and individual component flows are monitored in the control room. Abnormal system conditions are alarmed in the control room on the ACS panel.

1.5.2.3.7.2.6 Technical Specifications. The plant technical specifications require that:

- Two component cooling water pumps on buses supplied by different EDGs together with their associated piping and valves be operable at all times when the reactor is critical. This condition may be modified to allow one CCS pump to be out of service provided it is restored to operation within 24 hours.

- Two component cooling heat exchangers and associated piping and valves be operable at all times when the reactor is critical. One CCS heat exchanger or other passive component may be out of service for a period not to exceed 48 hours provided the system still operates at design accident capability.

- Two auxiliary component cooling pumps together with their associated piping and valves are operable at all times when the reactor is critical. One auxiliary component cooling pump may be out of service provided it is restored to an operable status within 24 hours and the other pump is demonstrated to be operable.

1.5.2.3.7.2.7 Testing and Maintenance.

1.5.2.3.7.2.7.1 Periodic testing. Periodic testing to verify the operability of the CCS is not required by the plant technical specifications as the system is required to support normal plant operation. Automatic starting of the CCS pumps and the auxiliary CCS pumps in response to safeguards actuation or recirculation switchover is performed every refueling cycle.

ASME Section XI requires monthly testing of the auxiliary component cooling water pumps. Motor-operated valves that are required to change position during plant emergency conditions are cycled during plant cold shutdown conditions. Air-operated valves are cycled quarterly.

Routine monitoring of the CCS is performed by the plant operators to determine system status.

1.5.2.3.7.2.7.2 Periodic maintenance. Periodic maintenance is performed as required on the components of the CCS. This maintenance includes items such as lubrication, inspection, and adjustment. One of the two CCS pumps powered from emergency diesel generator 22 (pump 22 or 23) may be out of service indefinitely without placing the plant in a limiting condition for operation. A review of plant work permits revealed two out of four maintenance actions that required more than 24 hours for completion (pump 23, 1977, 872 hours; pump 23, 1978, 339 hours). Using this plant data, the frequency of pump maintenance is:

Mean: 8.37×10^{-5} hours^{-1}

Variance: 5.21×10^{-10}

The duration of this maintenance depends upon the pump being maintained. Pump 21 is limited to 24 hours out of service time because it is supplied from a single EDG. Pumps 22 and 23 receive power from a common EDG and the plant technical specifications do not limit the out of service time for any one of these two pumps as long as the other pump is operable. The duration of maintenance for pump 21 is:

Mean: 6.25 hours

Variance: 53.31

Combining with the frequency of maintenance the unavailability due to maintenance for pump 21 is:

Mean: 1.39×10^{-3}

Variance: 4.11×10^{-7}

For pump 22 or 23, plant data give the duration of maintenance as:

Mean: 305 hours

Variance: 410

Combining with the frequency of maintenance, the unavailability due to maintenance for pump 22 or 23 is:

Mean: 4.19×10^{-2}

Variance: 8.18×10^{-4}

Upon completion of pump maintenance, testing is required to determine pump operability and to ensure correct system lineup. At the completion of this testing, the pump is returned to its normal lineup (auto or running).

1.5.2.3.7.2.8 Operator Interaction With The Component Cooling System. As this system is required to support normal plant operation, most operator errors that affect system operation will be annunciated or indicated in the control room within a short period of time after their occurrence. These errors include placing the standby pump switch in the "Pull-Out" position or mispositioning manual or power-operated valves. These errors do not contribute to system unavailability on demand during accident conditions.

Operator error after maintenance is precluded by the testing that is performed at the completion of the maintenance.

Operator error during the shift from the injection phase to the recirculation phase of LOCAs is possible and is discussed in the recirculation system description.

1.5.2.3.7.2.9 Common Cause Analysis. Table 1.5.2.3.7-3 represents a listing of the components included in the CCS analysis, their failure mode, location, and susceptibility to various causes of common mode failure. The contribution of common mode failures to system failure is presented in Section 1.5.2.3.7.4.6 of this analysis.

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1.5.2.3.7.3 System Fault Tree Modeling and Results.

1.5.2.3.7.3.1. Event Trees. In the event trees, CCS appears with the recirculation phase events.

1.5.2.3.7.3.2 System Fault Trees. Figure 1.5.2.3.7-4 presents the fault tree developed for the Indian Point 2 CCS. The top event, "No or Insufficient Flow (NOIF) from the Component Cooling System" is defined as flow delivered to the supply header is less than the capacity of one CCS pump. Two basic cases are analyzed using this fault tree.

- Case 1. SI actuation has occurred, no offsite power. The CCS pumps are not started until the recirculation phase of the accident sequence, pump starting is operator-controlled.

- Case 2. SI actuation has occurred, offsite power is available. The CCS pumps are sequenced onto their respective 480V bus during the initial stages of the accident sequence, no operator action is required to start the CCS pumps.

1.5.2.3.7.3.3 Fault Tree Coding. Table 1.5.2.3.7-3 is a list of basic events, their failure modes, corresponding codes, and failure rates.

1.5.2.3.7.3.4 Minimal Cutsets. The minimal cutsets for the CCS are identified in Table 1.5.2.3.7-4.

The single event cutsets, block F of Figure 1.5.2.3.7-2, consist of the surge tank, the isolation valves to and from the safety injection and the residual heat removal pumps, and the failures of the service water supply to the CCS (no flow from the service water header and the service water isolation valve transfers closed). A sixth single event cutset is failure of the CCS piping. The piping failure effects table (Table 1.5.2.3.7-5) presents the results of the analysis of piping failures on the CCS system.

The two event cutsets, blocks D and E of Figure 1.5.2.3.7-2, consist of failures in the two heat exchanger trains. Block D consists of the following basic events:

- TXV34--C: Service water inlet valve SWN-34 transfers closed.
- TXV3S--C: Service water outlet valve SWN-35 transfers closed.
- UXV766AC: Heat exchanger 21 inlet valve 766A transfers closed.
- UXV765AC: Heat exchanger 21 outlet valve 765A transfers closed.
- UHE0021L: Heat exchanger 21 loss of cooling capability (rupture, plugging, etc.).

Block E consists of the following basic events:

- TXV34-1C: Service water inlet valve SWN-34-1 transfers closed.
- TXV35-1C: Service water outlet valve SWN-35-1 transfers closed.
- UXV766BC: Heat exchanger 22 inlet valve 766B transfers closed.
- UXV765BC: Heat exchanger 22 outlet valve 765B transfers closed.

- TXV33--C: Service water crossover valve SWN-33 transfers closed.
- TXV31-1C: Service water crossover valve SWN-31-1 transfers closed.
- UHE0022L: Heat exchanger 22 loss of cooling capability (rupture, plugging, etc.)

Blocks A, B, and C of Figure 1.5.2.3.7-2 identify the components that comprise the three-event cutsets. Block A consists of the following basic events:

- JBS-25AD: No power at switchgear bus 5A.
- 4BS-25AD: No control power at switchgear bus 5A.
- UXV760CC: Pump 21 suction valve 760C transfers closed.
- UXV762CC: Pump 21 discharge valve 762C transfers closed.
- UCV761CQ: Pump 21 discharge check valve 761C fails closed.
- UPM0021S: Pump 21 fails mechanically.
- UM00021S: Motor for pump 21 fails.
- UCC0021F: Control circuit for pump 21 fails.

Block B consists of the following basic events:

- JBS-22AD: No power at switchgear bus 2A.
- 4BS-22AD: No control power at switchgear bus 2A.
- UXV760BC: Pump 22 suction valve 760B transfers closed.
- UXV762BC: Pump 22 discharge valve 762B transfers closed.
- UCV761BQ: Pump 22 discharge check valve 761B fails closed.
- UPM0022S: Pump 22 fails mechanically.
- UM00022S: Motor for pump 22 fails.
- UCC0022F: Control circuit for pump 22 fails.

Block C consists of the following basic events:

- JBS-23AD: No power at switchgear bus 3A.
- 4BS-23AD: No control power at switchgear bus 3A.
- UXV760AC: Pump 23 suction valve 760A transfers closed.
- UXV762AC: Pump 23 discharge valve 762A transfers closed.
- UCV761AQ: Pump 23 discharge check valve 761A transfers closed.
- UPM0023S: Pump 23 fails mechanically.
- UM00023S: Motor for pump 23 fails.
- UCC0023F: Control circuit for pump 23 fails.

1.5.2.3.7.4 Quantification Boundary Condition, Offiste Power Available.

1.5.2.3.7.4.1 Quantification of Single Failures (Block F) (Hardware). Block F identifies the single event failures which result in system failure. These events are:

- Surge tank failure (leak/rupture)

  Mean: 8.60×10^{-10} probability of failure per hour

  Variance: 6.00×10^{-17}

- Valve 734A is closed. The valve is normally open and the failure of interest is the valve transfers closed. This failure causes low flow alarms in the control room (residual heat removal pump cooling low flow) and would be detected immediately upon occurrence. A plant shutdown would be required to repair this valve.

  Mean: 7.40×10^{-8} probability of failure per hour

  Variance: 5.89×10^{-15}

- Valve 734B is closed. This valve is also normally open and the failure of interest is the valve transfers closed. This failure results in the same alarms as 734A. A plant shutdown would be required to repair this valve.

  Mean: 7.40×10^{-8} probability of failure per hour

  Variance: 5.89×10^{-15}

  Note: Failure of either valve 734A or 734B results in failure of the safety injection pumps if operating. Under the definitions used for system success, this is failure of the CCS; however, the majority of the CSS is still intact and operable under this condition.

- Valve SWN-32 is closed. This valve is normally open and the failure of interest is the valve transfers closed. This failure results in high temperature alarms in the control room (CCS heat exchanger outlet). A plant shutdown may be required to repair this valve.

  Mean: 7.40×10^{-8} probability of failure per hour

  Variance: 5.89×10^{-15}

- No flow from the conventional service water header. This failure results in plant shutdown and is detected upon occurrence. This event is quantified at the event tree level and is shown here only for completeness.

- Pipe failures. Table 1.5.2.3.7-5 identifies the pipe sections whose failure results in CCS failure. The mean and variance for a failure in a single section of pipe are:

  Mean: 8.60×10^{-10} probability of failure per hour per section

  Variance: 6.00×10^{-17}

  There are 18 sections of CCS piping whose failure results in system failure. This results in the following piping contribution to failure:

  Mean: 1.55×10^{-8}

  Variance: 1.94×10^{-14}

The single event random failure rate (probability of failure per hour) is:

$Q_{Block\ F}$ = surge tank + valves + pipes = 2.38×10^{-7}

Variance: 5.68×10^{-14}

The failures previously described require immediate plant shutdown if they occur during plant operation. For this reason, single failures prior to the initiating event are not considered in this analysis.

The single failures which affect this analysis are those which occur after the initiating event. The time of interest is the first 24 hours after the initiating event. For this period the mean and variance for the probability of system failure due to single hardware failures are:

Mean: 5.72×10^{-6}

Variance: 3.27×10^{-11}

1.5.2.3.7.4.2. Quantification of Two Event Cutsets (Blocks D and E) (Hardware). As stated in Section 1.5.2.3.7.3.4., the two-event cutset contribution to system failure consists of failures in the heat exchanger trains, blocks D and E of Figure 1.5.2.3.7-2. Block D consists of:

- Manual valves (service water) (2):

  Mean: 7.40×10^{-8} probability of failure per hour

  Variance: 5.89×10^{-15}

- Manual valves (CCS) (2):

  Mean: 7.40×10^{-8} probability of failure per hour

  Variance: 5.89×10^{-15}

- Heat exchanger:

  Mean: 8.42×10^{-7} probability of failure per hour

  Variance: 1.94×10^{-12}

This results in the following contribution to system failure (per hour) for block D:

$Q_{Block\ D}$: 1.14×10^{-6}

Variance: 1.76×10^{-12}

For block E the contribution is the same as block D plus two additional service water valves.

$Q_{Block\ E}$: 1.29×10^{-6}

Variance: 1.87×10^{-12}

Those failures which occur in the heat exchanger trains during plant operation do not affect this analysis. The failures in the heat exchanger trains which affect this analysis are those which occur during the first 24 hours after the initiating event. For this time period the following distributions describe the probability of failure of blocks D and E:

$Mean_D$: 2.74×10^{-5}

$Variance_D$: 1.01×10^{-9}

$Mean_E$: 3.10×10^{-5}

$Variance_E$: 1.08×10^{-9}

System success requires that one of the two heat exchanger trains remain operable for the first 24 hours after the initiating event. This results in the following distribution for the probability of system failure due to random failures in both heat exchanger trains:

Mean: 1.96×10^{-9}

Variance: 1.09×10^{-16}

1.5.2.3.7.4.3 Quantification of Three-Event Cutsets (Blocks A, B, C) (Hardware Failures). As stated in Section 1.5.2.3.7.3.4, the three-event cutset contribution to system failure consists of random failures in the pump trains, blocks A, B, and C of Figure 1.5.2.3.7-1. For block A these are:

- Pump (includes motor and controls)
  - Fails to continue running:

    Mean: 2.76×10^{-6} probability of failure per hour

    Variance: 1.59×10^{-11}
  - Fails to start:

    Mean: 6.41×10^{-3} probability of failure on demand

    Variance: 7.78×10^{-6}
- Manual valve (2)
  - Transfers closed:

    Mean: 7.40×10^{-8} probability of failure per hour

    Variance: 5.89×10^{-15}
- Check valve
  - Fails to open:

    Mean: 7.02×10^{-5} probability of failure on demand

    Variance: 1.09×10^{-8}

Blocks B and C consist of similar components. For an operating pump, the probability of failure per hour is described by the following probability distribution (made up of pump failure to continue running and manual valves failing closed):

Mean: 2.31×10^{-6}

Variance: 1.34×10^{-11}

For a time t = 24 hours, we have the following distribution for failure of an operating pump train:

Mean: 5.54×10^{-5}

Variance: 7.69×10^{-9}

At Indian Point 2, all operating CCS pumps are electrically stripped from the 480V switchgear buses upon receipt of a safety injection signal. Depending upon the status of the electric power system, the CCS pumps will either be started as a result of the safeguards sequence signal (with offsite power available) or as a result of the operator action which occurs when entering the recirculation phase of the accident (with diesel generators available). The probability of failure to start on demand of a previously operating CCS pump train consists of pump failure to start on demand, check valve failure to open on demand, and the transferring closed of either the pump suction or discharge valves during the time the pump is idle. For time $\leq$ 1 hour, the probability of failure on demand of a single manual valve is:

Mean: 7.40×10^{-8}

Variance: 5.89×10^{-15}

For a single previously operating pump train, the probability of failure on demand is described by the following distribution:

Mean: 6.48×10^{-3}

Variance: 7.36×10^{-6}

Given a successful start, the CCS pump must operate for 24 hours. The total probability of failure for a single previously operating CCS pump train is now:

Mean: 6.54×10^{-3}

Variance: 6.95×10^{-6}

During plant operation, one CCS pump train is normally in standby (unless it is isolated for maintenance). Pump failure to start on demand and check valve failure to open on demand remain as previously defined. However, the manual valves' contribution to pump train failure on demand must be developed.

Plant procedures do not require routine shifting of the CCS pumps and the pumps are not routinely tested.* A standby CCS pump can conceivably remain idle for an entire plant cycle (refueling to refueling). This is nominally 18 months. Valve failure (transferring closed) could have occurred at any time during this 18-month cycle. The fault detection time for this event is taken as one-half of the test interval (9 months). This results in the following distribution for failure of a single manual valve in the standby pump train:

Mean: 4.55×10^{-4}

Variance: 2.47×10^{-7}

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*Since this analysis was performed, the testing requirements for the standby pump were changed to monthly and the quantification presented here is conservative.

The failure of the standby pump train to start on demand is now described by the following mean and variance:

Mean: 7.44×10^{-3}

Variance: 2.66×10^{-6}

Given a successful start, the pump must continue to run for 24 hours. This results in a total failure probability for the standby pump of:

Mean: 7.51×10^{-3}

Variance: 7.82×10^{-6}

The following expression defines the success criteria for the CCS pumps with differing probabilities for the status of the standby pump:

$$Q_{Pumps} = P(1S)\left[\binom{2}{2} P(OP)^2 \times P(STBY)\right] + P(OS)\left[\binom{2}{2} P(OP)^2\right]$$

where

P(1S) = Probability of having one pump in standby (which equals 1 - (probability of 21 in maintenance + 2 x probability of 22 or 23 in maintenance)) = 0.915

P(OS) = Probability of having zero pumps in standby (which equals the probability of 21 in maintenance + 2 x probability of 22 or 23 in maintenance) = 0.085

P(OP) = Probability of failure of a running (or previously running) pump (to t = 24 hours)

P(STBY) = Probability of failure of the standby pump (to t = 24 hours)

For the pump contribution to system failure with power available at all 480V switchgear buses, the distribution is:

Mean: 4.55×10^{-6}

Variance: 2.58×10^{-12}

1.5.2.3.7.4.4 Quantification of Test and Maintenance. There is no contribution to system failure due to testing that is performed on the CCS. The maintenance contribution to system failure is included with the quantification of the pump trains' effect on system failure.

1.5.2.3.7.4.5 Quantification of Human Interaction. The operator error of failing to switch from injection to recirculation is presented in the recirculation system analysis and is not quantified in this analysis. No other human interaction is identified for this system.

1.5.2.3.7.4.6 Quantification of Common Cause. Although there are many similar components sharing common locations in the CCS, a large portion of these components are not highly susceptible to common cause failure mechanisms because they perform a passive function. These items include manual valves, check valves, tanks, heat exchangers, and piping. The active components of the system, the CCS pumps and various motor-operated valves, are more likely candidates for common cause failure and are discussed below. External events such as earthquakes or flooding are discussed elsewhere in this study.

1. Fire. The three CCS pumps share a common room in the primary auxiliary building at Elevation 68'. The "Review of the Indian Point Station Fire Protection Program" described this area as having a low fire loading and postulated no fires which could affect all three CCS pumps.

2. Moisture. The CCS heat exchangers, the CCS surge tank, and the piping and valves for alignment and isolation of this equipment are located in the vicinity of the CCS pumps. Leakage (spray) from these components is detectable during plant operation and would be corrected before damage occurred. Therefore, this common cause failure is not quantified.

3. Grit. During plant operation, no grit-producing activities occur. During plant shutdown, these activities are protected against by plant procedures. This mechanism for common cause failure is not quantified for this analysis.

4. Other Causes. Other common cause susceptibilities such as manufacturer, and test and maintenance procedures, are possible contributors to common cause failure of the CCS pumps. However, the plant test program, maintenance program, and technical specifications combine to (1) aid in the discovery of pump problems, and (2) limit the effects of common cause failures. No quantification is performed for these causes of failure.

   Note: the CCS pump breakers are susceptible to the common cause failure mechanisms of fire, moisture, and grit due to their common location in the switchgear room. Quantification and discussion of these effects is presented elsewhere in this study because the entire plant could be affected.

1.5.2.3.7.4.7 System Failure Quantification. The failure frequency per demand for the CCS includes the following contributors: single, double, and triple random hardware failures; test and maintenance in conjunction with random hardware failures; human error; and common cause.

The probability of failure of the CCS to time t = 24 hours is characterized by the following mean and variance:

$$Q_{System} = \alpha singles + \alpha doubles + \alpha triples + \alpha T\&M + \alpha operator\ error + \alpha common\ cause = 1.03 \times 10^{-5}$$

Variance: 5.69×10^{-11}

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1.5.2.3.7.5 Quantification Boundary Condition Loss of Offsite Power, Loss of Onsite Power.

1.5.2.3.7.5.1. Loss of a Single 480V Bus (bus 5A). This failure results in the failure of a single CCS pump train which results in a one out of two success requirement for the remaining pump trains. For the loss of a single 480V bus, the following equation defines the probability of system failure due to pump train failures:

$$Q_{Pumps} = P(1S)\ [P(OP) \times P(STBY)] + P(OS)\ [P(OP)]$$

where the terms of the equation remain as defined in Section 1.5.2.3.7.4.3. (This equation is true for loss of a 480V bus which was supplying a previously operating CCS pump. If the 480V bus was supplying the standby pump, the numerical results using this equation will be conservative.)

This results in the contribution to system failure due to pump train failure to time = 24 hours described by the following mean and variance:

Q_{Pumps}: 6.02×10^{-4}

Variance: 1.90×10^{-7}

The probability of system failure to time t = 24 hours is now:

Q_{System}: 6.07×10^{-4}

Variance: 1.90×10^{-7}

1.5.2.3.7.5.2 Loss of a Single Emergency Diesel Generator (EDG) (loss of two 480V buses). Pumps 22 and 23 receive emergency power from a single EDG. This is the worst case condition for loss of a single EDG. For this case, the following equation defines the probability of system failure due to pump train failure:

$$Q_{Pumps} = P(1S)P(OP) + P(OS)P(OP)$$

where the terms of the equation are defined in Section 1.5.2.3.7.4.3 of this analysis.

This results in the following contribution to system failure due to pump train failure:

Q_{Pumps}: 6.54×10^{-3}

Variance: 6.95×10^{-6}

The probability of system failure is now:

Q_{System}: 6.54×10^{-3}

Variance: 6.95×10^{-6}

TABLE 1.5.2.3.7-1

INDIAN POINT 2 SUMMARY OF RESULTS - COMPONENT COOLING SYSTEM ANALYSIS

	Mean	Variance	5th Percentile	95th Percentile	Median	W-1400
Case 1 Boundary Condition - Power at Buses 2A, 3A, 5A, t = 24 Hours						
Single Events	5.7×10^{-6}	3.2×10^{-11}	8.9×10^{-7}	1.4×10^{-5}	3.6×10^{-6}	No Comparable Analysis
Heat Exchanger Trains	2.0×10^{-9}	1.1×10^{-16}	2.7×10^{-11}	5.0×10^{-9}	3.3×10^{-10}	
Pump Trains	4.6×10^{-6}	2.3×10^{-12}	5.3×10^{-7}	1.2×10^{-5}	2.6×10^{-6}	
Test and Maintenance		(with pump trains)				
Human Error	*					
Common Cause	*					
Other	*					
System Total	1.0×10^{-5}	5.7×10^{-11}	2.6×10^{-6}	2.2×10^{-4}	7.6×10^{-6}	
Case 2 Boundary Condition - Power at Two of Three Vital Buses (Bus 5A, 2A, or 3A Down), t = 24 hours						
Single Events	5.7×10^{-6}	3.2×10^{-11}	8.9×10^{-7}	1.4×10^{-5}	3.6×10^{-6}	No Comparable Analysis
Heat Exchanger Trains	2.0×10^{-9}	1.1×10^{-16}	2.7×10^{-11}	5.0×10^{-9}	3.3×10^{-10}	
Pump Trains	6.0×10^{-4}	1.9×10^{-7}	1.5×10^{-4}	1.3×10^{-3}	4.4×10^{-4}	
Test and Maintenance		(with pump trains)				
Human Error	*					
Common Cause	*					
Other	*					
System Total	6.1×10^{-4}	1.9×10^{-7}	1.6×10^{-4}	1.3×10^{-3}	4.5×10^{-4}	
Case 3 Boundary Condition - Loss of Power at Two of Three Vital Buses (Loss of 2A, 3A), t = 24 Hours						
Single Events	5.7×10^{-6}	3.2×10^{-11}	8.9×10^{-7}	1.4×10^{-5}	3.6×10^{-6}	No Comparable Analysis
Heat Exchanger Trains	2.0×10^{-9}	1.1×10^{-16}	2.7×10^{-11}	5.0×10^{-9}	3.3×10^{-10}	
Pump Trains	6.5×10^{-3}	6.9×10^{-6}	4.4×10^{-3}	9.9×10^{-3}	5.7×10^{-3}	
Test and Maintenance		(with pump trains)				
Human Error	*					
Common Cause	*					
Other	*					
System Total	6.5×10^{-3}	6.9×10^{-6}	2.8×10^{-3}	9.9×10^{-3}	5.7×10^{-3}	

*Negligibly small failure probability.

TABLE 1.5.2.3.7-2

INDIAN POINT 2 REQUIRED CCS FLOWS FOR PLANT CONDITIONS

Components Cooled	Normal Operation Flow (gpm)		Shutdown Flow (gpm)		Accident Conditions Flow (gpm)	
	Component	Total	Component	Total	Component	Total
1. High Head Safety Injection Pumps	15/pump	45	15/pump	45	15/pump	45
2. Residual Heat Pumps	15/pump	30	15/pump	30	15/pump	30
3. Residual Heat Exchangers	-	-	-	4,000	-	4,000
4. Recirculation Pumps	-	-	-	-	40/pump	80
5. Spent Fuel Pit Heat Exchanger	2,000	2,000	2,000	2,000	-	-
6. Reactor Coolant Pumps						
a. Upper Motor Bearing Heat Exchanger	150	600	-	-	-	-
b. Lower Motor Bearing Heat Exchanger	5	20	-	-	-	-
c. Pump Thermal Barrier	25	100	-	-	-	-
7. Letdown Heat Exchanger		1,000		-		-
8. Seal Water Heat Exchanger		200		-		-
9. Primary Makeup Water Heat Exchanger		400		-		-
10. Boric Acid Regeneration System		815		-		-
11. Waste Evaporation System		155		-		-
12. Charging Pumps	90	270	-	-	-	-
13. Excess Letdown Heat Exchanger		230		-		-
14. Reactor Vessel Support Blocks		50		-		-
15. Miscellaneous Sample Heat Exchangers		168		-		-
		6,100		6,075		4,155
	two of three pumps one of two heat exchangers		two of three pumps one of two heat exchangers		one of three pumps one of two heat exchangers	

TABLE 1.5.2.3.7-3

INDIAN POINT 2 BASIC EVENT DATA - COMPONENT COOLING

Event Description and Failure Mode	Fault Tree Coding	Failure Data					Common Cause Data		Comments
		Mean	H/D	Variance	MTTR	Reference*	Location	Susceptibility	
CC pump 21 does not start/ Does not continue to run	UPM0021S	6.41×10^{-3} 2.76×10^{-6}	D H	7.78×10^{-6} 1.59×10^{-11}	NA in text	11 15	PAB El 68' Component Cooling Pump Room	V, H, I	
CC pump 22 does not start/ Does not continue to run	UPM0022S	6.41×10^{-3} 2.76×10^{-6}	D H	7.78×10^{-6} 1.59×10^{-11}	NA in text	11 15	PAB El 68' Component Cooling Pump Room	V, H, I	
CC pump 23 does not start/ Does not continue to run	UPM0023S	6.41×10^{-3} 2.76×10^{-6}	D H	7.78×10^{-6} 1.59×10^{-11}	NA in text	11 15	PAB El 68' Comppnent Cooling Pump Room	V, H, I	
CC heat exchanger 21, Loss of cooling capability (leak or rupture	UHE0021L	8.42×10^{-7}	H	1.44×10^{-12}	in text	24	PAB El 80' to 98', Above Pumps	I	
CC heat exchanger 22, Loss of cooling capability (leak or rupture	UHE0022L	8.42×10^{-7}	H	1.94×10^{-12}	in text	24	PAB El 80' to 98', Above Pumps	I	
CC pump motor 21, does not start/run	UM00021N	-	-	-	-	-	Same as Pump	V, I, H, M	With Pump
CC pump motor 22, does not start/run	UM00022N	-	-	-	-	-	Same as Pump	V, I, H, M	With Pump
CC pump motor 23, does not start/run	UM00023N	-	-	-	-	-	Same as Pump	V, I, H, M	With Pump
CC pump 21 breaker, does not close/transfer open	UCB0021X	-	-	-	-	-	Switchgear Bus 5A	V, I, H, M	With Pump
CC pump 22 breaker, does not close/transfer open	UCB0022X	-	-	-	-	-	Switchgear Bus 2A	V, I, H, M	With Pump
CC pump 23 breaker, does not close/transfer open	UCB0023X	-	-	-	-	-	Switchgear Bus 3A	V, I, H, M	With Pump
No power at switchgear bus 5A	JBS-25AD	-	-	-	-	-	Containment Building El 15'	See EP analysis	See EP Analysis
No power at switchgear bus 2A	JBS-22AD	-	-	-	-	-	Containment Building El 15'	"	"
No power at switchgear bus 3A	JBS-23AD	-	-	-	-	-	Containment Building El 15'	"	"
No control power at switchgear bus 5A	4BS-25AD	-	-	-	-	-	Containment Building El 15'	"	"
No control power at switchgear bus 2A	4BS-22AD	-	-	-	-	-	Containment Building El 15'	"	"
No control power at switchgear bus 3A	HBS-23AD	-	-	-	-	-	Containment Building El 15'	"	"
No flow from service water supply header (conventional)	TSW2NOFL	-	-	-	-	-	NA	-	See SW Analysis

*Reference - Refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.3.7-3 (continued)

INDIAN POINT 2 BASIC EVENT DATA - COMPONENT COOLING

Event Description and Failure Mode	Fault Tree Coding	Failure Data					Common Cause Data		Comments
		Mean	H/D	Variance	MTTR	Reference*	Location	Susceptibility	
CC surge tank, leak or rupture	UTK0021L	8.60×10^{-10}	H	6.00×10^{-17}	See text	43	PAB El 98'	I	Same as pipe
Pump 21 suction valve transfers closed	UXV760CC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Pump section	I	
Pump 22 suction valve transfers closed	UXV760BC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Pump section	I	
Pump 23 suction valve transfers closed	UXV760AC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Pump section	I	
Pump 21 discharge check valve fails to open	UCV761CQ	7.02×10^{-5}	D	1.09×10^{-8}	-	3	Pump discharge	I	
Pump 22 Discharge check valve fails to open	UCV761BQ	7.02×10^{-5}	D	1.09×10^{-8}	-	3	Pump discharge	I	
Pump 23 discharge check valve fails to open	UCV761AQ	7.02×10^{-5}	D	1.09×10^{-8}	-	3	Pump discharge	I	
Pump 21 discharge valve transfers closed	UXV762CC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Pump discharge	I	
Pump 22 discharge valve transfers closed	UXV762BC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Pump discharge	I	
Pump 23 discharge valve transfers closed	UXV762AC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Pump discharge	I	
Heat exchange 21 Inlet valve transfers closed	UXV766AC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Near heat exchanger	I	
Heat Exchange 22 Inlet valve transfers closed	UXV766BC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Near heat exchanger	I	
Heat Exchange 21 Outlet valve transfers closed	UXV765AC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Near heat exchanger	I	
Heat Exchange 22 Outlet valve transfers closed	UXV765BC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Near heat exchanger	I	
Valve 734A transfers closed	UXV734AC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Near pumps, PAB	I	
Valve 734B transfers closed	UXV734BC	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Near pumps, PAB	I	
SW inlet to heat exchanger 21 transfers closed	TXV34--C	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	PAB near heat exchanger	I	
SW inlet to heat exchanger 22 transfers closed	TXV34-1C	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	PAB near heat exchanger	I	

*Reference - Refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.3.7-3 (continued)

INDIAN POINT 2 BASIC EVENT DATA - COMPONENT COOLING

Event Description and Failure Mode	Fault Tree Coding	Failure Data					Common Cause Data		Comments
		Mean	H/D	Variance	MTTR	Reference*	Location	Susceptibility	
SW outlet from heat exchanger 21 transfers closed	TXV35--C	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	PAB near heat exchanger	I	
SW outlet from heat exchanger 22 transfers closed	TXV35-1C	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	PAB near heat exchanger	I	
SW supply isolation, 31, transfers closed	TXV31--C	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Valve pit (PAB)	I	
SW supply isolation, 32, transfers closed	TXV32--C	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Valve pit (PAB)	I	
SW supply isolation, 33, transfers closed	TXV33--C	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Valve pit (PAB)	I	
SW supply isolation, 31-1, transfers closed	TXV31-1C	7.40×10^{-8}	H	5.89×10^{-15}	See text	1	Valve pit (PAB)	I	
CC pipe failure	UPPFAILS	8.60×10^{-10}	H	6.00×10^{-17}	See text	43	Various	-	

*Reference - Refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.3.7-4

INDIAN POINT 2 MINIMAL CUTSETS FOR COMPONENT COOLING WATER SYSTEM

CUTSETS WITH 1 BASIC EVENT.

5)	1)	UXV734AC	2)	UTK0021L	3)	UXV734BC	4)	UPPFAILS	5)	TSW1NOFL	
6)	6)	TXV32--C									

CUTSETS WITH 2 BASIC EVENTS.

10)	1)	TXV32--C	TXV36-1C	2)	TVX36--C	TXV36-1C	3)	UXV766AC	TXV35-1C	4)	UHE0021L	TXV36-1C
14)	5)	UXV765AC	TXV36-1C	6)	TXV34--C	UXV766BC	7)	TXV36--C	UXV766BC	8)	UXV766AC	UVX766BC
18)	9)	UHE0021L	UXV766BC	10)	UXV765AC	UXV766BC	11)	TXV34--C	UHE0022L	12)	TXV36--C	UHE0022L
22)	13)	UXV766AC	UHE0022L	14)	UHE0021L	UHE0022L	15)	UXV765AC	UHE0022L	16)	TXV34--C	UXV765BC
26)	17)	TXV36--C	UXV765BC	18)	UXV766AC	UXV765BC	19)	UHE0021L	UXV765BC	20)	UXV765AC	UXV765BC
30)	21)	TXV34--C	TXV34-1C	22)	TXV36--C	TXV34-1C	23)	UXV766AC	TXV34-1C	24)	UHE0021L	TXV34-1C
34)	25)	UXV765AC	TXV34-1C	26)	TXV34--C	TXV33--C	27)	TXV36--C	TXV33--C	28)	UXV766AC	TXV33--C
38)	29)	UHE0021L	TXV33--C	30)	UXV765AC	TXV33--C	31)	TXV34--C	TXV33-1C	32)	TXV36--C	TXV33-1C
41)	33)	UXV766AC	TXV33-1C	34)	UHE0021L	TXV33-1C	35)	UXV765AC	TXV33-1C			

CUTSETS WITH 3 BASIC EVENTS.

44)	1)	UPM0023S	UPM0022S	UPM0021S	2)	UCC0023F	UPM0022S	UPM0021S	3)	UXV762AC	UPM0022S	UPM0021S
47)	4)	4BS-23AD	UPM0022S	UPM0021S	5)	UPM0023S	UCC0022F	UPM0021S	6)	UCC0023F	UCC0022F	UPM0021S
50)	7)	UXV762AC	UCC0022F	UPM0021S	8)	4BS-23AD	UCC0022F	UPM0021S	9)	UPM0023S	UXV762BC	UPM0021S
53)	10)	UCC0023F	UXV762BC	UPM0021S	11)	UXV762AC	UXV762BC	UPM0021S	12)	4BS-23AD	UXV762BC	UPM0021S
56)	13)	UPM0023S	4BS-22AD	UPM0021S	14)	UCC0023F	4BS-22AD	UPM0021S	15)	UXV762AC	4BS-22AD	UPM0021S
59)	16)	4BS-23AD	4BS-22AD	UPM0021S	17)	UPM0023S	UPM0022S	UCC0021F	18)	UCC0023F	UPM0022S	UCC0021F
62)	19)	UXV762AC	UPM0022S	UCC0021F	20)	4BS-23AD	UPM0022S	UCC0021F	21)	UPM0023F	UCC0022F	UCC0021F
65)	22)	UCC0023F	UCC0022F	UCC0021F	23)	UXV762AC	UCC0022F	UCC0021F	24)	4BS-23AD	UCC0022F	UCC0021F
68)	25)	UPM0023S	UXV762BC	UCC0021F	26)	UCC0023F	UXV762BC	UCC0021F	27)	UXV762AC	UXV762BC	UCC0021F
71)	28)	4BS-23AD	UXV762BC	UCC0021F	29)	UPM0023S	4BS-22AD	UCC0021F	30)	UCC0023F	4BS-22AD	UCC0021F
74)	31)	UXV762AC	4BS-22AD	UCC0021F	32)	4BS-23AD	4BS-22AD	UCC0021F	33)	UPM0023S	UPM0022S	UXV762CC
77)	34)	UCC0023F	UPM0022S	UXV762CC	35)	UXV762AC	UPM0022S	UXV762CC	36)	4BS-23AD	UPM0022S	UXV762CC
80)	37)	UPM0023S	UCC0022F	UXV762CC	38)	UCC0023F	UCC0022F	UXV762CC	39)	UXV762AC	UCC0022F	UXV762CC
83)	40)	4BS-23AD	UCC0022F	UXV762CC	41)	UPM0023S	UXV762BC	UXV762CC	42)	UCC0023F	UXV762BC	UXV762CC
86)	43)	UXV762AC	UXV762BC	UXV762CC	44)	4BS-23AD	UXV762BC	UXV762CC	45)	UPM0023S	4BS-22AD	UXV762CC
89)	46)	UCC0023F	4BS-22AD	UXV762CC	47)	UXV762AC	4BS-22AD	UXV762CC	48)	4BS-23AD	4BS-22AD	UXV762CC
92)	49)	UPM0023S	UPM0022S	4BS-25AD	50)	UCC0023F	UPM0022S	4BS-25AD	51)	UXV762AC	UPM0022S	4BS-25AD

TABLE 1.5.2.3.7-4 (continued)

INDIAN POINT 2 MINIMAL CUTSETS FOR COMPONENT COOLING WATER SYSTEM

CUTSETS WITH 3 BASIC EVENTS.

95)	52)	4BS-23AD	UPM0022S	4BS-25AD	53)	UPM0023S	UCC0022F	4BS-25AD	54)	UCC0023F	UCC0022F	4BS-25AD
98)	55)	UXV762AC	UCC0022F	4BS-25AD	56)	4BS-23AD	UCC0022F	4BS-25AD	57)	UPM0023S	UXV762BC	4BS-25AD
101)	58)	UCC0023F	UXV762BC	4BS-25AD	59)	UXV762AC	UXV762BC	4BS-25AD	60)	4BS-23AD	UXV762BC	4BS-25AD
104)	61)	UPM0023S	4BS-22AD	4BS-25AD	62)	UCC0023F	4BS-22AD	4BS-25AD	63)	UXV762AC	4BS-22AD	4BS-25AD
107)	64)	4BS-23AD	4BS-22AD	4BS-25AD	65)	UPM0023S	UPM0022S	JBS-25AD	66)	UCC0023F	UPM0022S	JBS-25AD
110)	67)	UXV762AC	UPM0022S	JBS-25AD	68)	4BS-23AD	UPM0022S	JBS-25AD	69)	UPM0023S	UCC0022F	JBS-25AD
113)	70)	UCC0023F	UCC0022F	JBS-25AD	71)	UXV762AC	UCC0022F	JBS-25AD	72)	4BS-23AD	UCC0022F	JBS-25AD
116)	73)	UPM0023S	UXV762BC	JBS-25AD	74)	UCC0023F	UXV762BC	JBS-25AD	75)	UXV762AC	UXV762BC	JBS-25AD
119)	76)	4BS-23AD	UXV762BC	JBS-25AD	77)	UPM0023S	4BS-22AD	JBS-25AD	78)	UCC0023F	4BS-22AD	JBS-25AD
122)	79)	UXV762AC	4BS-22AD	JBS-25AD	80)	4BS-23AD	4BS-22AD	JBS-25AD	81)	UPM0023S	UPM0022S	UXV760CC
125)	82)	UCC0023F	UPM0022S	UXV760CC	83)	UXV762AC	UPM0022S	UXV760CC	84)	4BS-23AD	UPM0022S	UXV760CC
128)	85)	UPM0023S	UCC0022F	UXV760CC	86)	UCC0023F	UCC0022F	UXV760CC	87)	UXV762AC	UCC0022F	UXV760CC
131)	88)	4BS-23AD	UCC0022F	UXV760CC	89)	UPM0023S	UXV762BC	UXV760CC	90)	UCC0023F	UXV762BC	UXV760CC
134)	91)	UXV762AC	UXV762BC	UXV760CC	92)	4BS-23AD	UXV762BC	UXV760CC	93)	UPM0023S	4BS-22AD	UXV760CC
137)	94)	UCC0023F	4BS-22AD	UXV760CC	95)	UXV762AC	4BS-22AD	UXV760CC	96)	4BS-23AD	4BS-22AD	UXV760CC
140)	97)	UPM0023S	UPM0022S	UM00021S	98)	UCC0023F	UPM0022S	UM00021S	99)	UXV762AC	UPM0022S	UM00021S
143)	100)	4BS-23AD	UPM0022S	UM00021S	101)	UPM0023S	UCC0022F	UM00021S	102)	UCC0023F	UCC0022F	UM00021S
146)	103)	UXV762AC	UCC0022F	UM00021S	104)	4BS-23AD	UCC0022F	UM00021S	105)	UPM0023S	UXV762BC	UM00021S
149)	106)	UCC0023F	UXV762BC	UM00021S	107)	UXV762AC	UXV762BC	UM00021S	108)	4BS-23AD	UXV762BC	UM00021S
152)	109)	UPM0023S	4BS-22AD	UM00021S	110)	UCC0023F	4BS-22AD	UM00021S	111)	UXV762AC	4BS-22AD	UM00021S
155)	112)	4BS-23AD	4BS-22AD	UM00021S	113)	UPM0023S	UPM0022S	UCV761CQ	114)	UCC0023F	UPM0022S	UCV761CQ
158)	115)	UXV762AC	UPM0022S	UCV761CQ	116)	4BS-23AD	UPM0022S	UCV761CQ	117)	UPM0023S	UCC0022F	UCV761CQ
161)	118)	UCC0023F	UCC0022F	UCV761CQ	119)	UXV762AC	UCC0022F	UCV761CQ	120)	4BS-23AD	UCC0022F	UCV761CQ
164)	121)	UPM0023S	UXV762BC	UCV761CQ	122)	UCC0023F	UXV762BC	UCV761CQ	123)	UXV762AC	UXV762BC	UCV761CQ
167)	124)	4BS-23AD	UXV762BC	UCV761CQ	125)	UPM0023S	4BS-22AD	UCV761CQ	126)	UCC0023F	4BS-22AD	UCV761CQ
170)	127)	UXV762AC	4BS-22AD	UCV761CQ	128)	4BS-23AD	4BS-22AD	UCV761CQ	129)	UPM0023S	JBS-25AD	JBS-22AD
173)	130)	UCC0023F	JBS-25AD	JBS-22AD	131)	UXV762AC	JBS-25AD	JBS-22AD	132)	4BS-23AD	JBS-25AD	JBS-22AD
176)	133)	UPM0023S	UXV760CC	JBS-22AD	134)	UCC0023F	UXV760CC	JBS-22AD	135)	UXV762AC	UXV760CC	JBS-22AD
179)	136)	4BS-23AD	UXV760CC	JBS-22AD	137)	UPM0023S	UPM0021S	JBS-22AD	138)	UCC0022F	UM00021F	JBS-22AD
182)	139)	UXV762AC	UM00021S	JBS-22AD	140)	4BS-23AD	UM00021S	JBS-22AD	141)	UPM0023S	UCV761CQ	JBS-22AD
185)	142)	UCC0023F	UCV761CQ	JBS-22AD	143)	UXV762AC	UCV761CQ	JBS-22AD	144)	4BS-23AD	UCV761CQ	JBS-22AD
188)	145)	UPM0023S	JBS-25AD	UXV760BC	146)	UCC0023F	JBS-25AD	UXV760BC	147)	UXV762AC	JBS-25AD	UXV760BC
191)	148)	4BS-23AD	JBS-25AD	UXV760BC	149)	UPM0023S	UXV760CC	UXV760BC	150)	UCC0023F	UXV760CC	UXV760BC
194)	151)	UXV762AC	UXV760CC	UXV760BC	152)	4BS-23AD	UXV760CC	UXV760BC	153)	UPM0023S	UM00021S	UXV760BC
197)	154)	UCC0023F	UM00021S	UXV760BC	155)	UXV762AC	UM00021S	UXV760BC	156)	4BS-23AD	UM00021S	UXV760BC
200)	157)	UPM0023S	UCV761CQ	UXV760BC	158)	UCC0023F	UCV761CQ	UXV760BC	159)	UXV762AC	UCV761CQ	UXV760BC
203)	160)	4BS-23AD	UCV761CQ	UXV760BC	161)	UPM0023S	JBS-25AD	UM00022S	162)	UCC0023F	JBS-25AD	UM00022S
206)	163)	UXV762AC	JBS-25AD	UM00022S	164)	4BS-23AD	JBS-25AD	UM00022S	165)	UPM0023S	UXV760CC	UN00022S
209)	166)	UCC0023F	UXV760CC	UM00022S	167)	UXV762AC	UXV760CC	UM00022S	168)	4BS-23AD	UXV760CC	UM00022S
212)	169)	UPM0023S	UM00021S	UM00022S	170)	UCC0023F	UM00021S	UM00022S	171)	UXV762AC	UM00021S	UM00022S
215)	172)	4BS-23AD	UM00021S	UM00022S	173)	UPM0023S	UCV761CQ	UM00022S	174)	UCC0023F	UCV761CQ	UM00022S
218)	175)	UXV762AC	UCV761CQ	UM00022S	176)	4BS-23AD	UCV761CQ	UM00022S	177)	UPM0023S	JBS-25AD	UCV761BQ
221)	178)	UCC0023F	JBS-25AD	UCV761BQ	179)	UXV762AC	JBS-25AD	UCV761BQ	180)	4BS-23AD	JBS-25AD	UCV761BQ
224)	181)	UPM0023S	UXV760CC	UCV761BQ	182)	UCC0023F	UXV760CC	UCV761BQ	183)	UXV762AC	UXV760CC	UCV761BQ
227)	184)	4BS-23AD	UXV760CC	UCV761BQ	185)	UPM0023S	UM00021S	UCV761BQ	186)	UCC0023F	UM00021S	UCV761BQ
230)	187)	UXV762AC	UM00021S	UCV761BQ	188)	4BS-23AD	UM00021S	UCV761BQ	189)	UPM0023S	UCV761CQ	UCV761BQ
233)	190)	UCC0023F	UCV761CQ	UCV761BQ	191)	UXV762AC	UCV761CQ	UCV761BQ	192)	4BS-23AD	UCV761CQ	UCV761BQ

TABLE 1.5.2.3.7-4 (continued)

INDIAN POINT 2 MINIMAL CUTSETS FOR COMPONENT COOLING WATER SYSTEM

CUTSETS WITH 3 BASIC EVENTS.

236)	193)	JBS-25AD	JBS-22AD	JBS-23AD	194)	UXV760CC	JBS-22AD	JBS-23AD	195)	UM00021S	JBS-22AD	JBS-23AD
239)	196)	UCV761CQ	JBS-22AD	JBS-23AD	197)	JBS-25AD	UXV760BC	JBS-23AD	198)	UXV760CC	UXV760BC	JBS-23AD
242)	199)	UM00021S	UXV760BC	JBS-23AD	200)	UCV761CQ	UXV760BC	JBS-23AD	201)	JBS-25AD	UM00022S	JBS-23AD
245)	202)	UXV760CC	UM00022S	JBS-23AD	203)	UM00021S	UM00022S	JBS-23AD	204)	UCV761CQ	UM00022S	JBS-23AD
248)	205)	JBS-25AD	UCV761BQ	JBS-23AD	206)	UXV760CC	UCV761BQ	JBS-23AD	207)	UM00021S	UCV761BQ	JBS-23AD
251)	208)	UCV761CQ	UCV761BQ	JBS-23AD	209)	JBS-25AD	JBS-22AD	UXV760AC	210)	UXV760CC	JBS-22AD	UXV760AC
254)	211)	UM00021S	JBS-22AD	UXV760AC	212)	UCV761CQ	JBS-22AD	UXV760AC	213)	JBS-25AD	UXV760BC	UXV760AC
257)	214)	UXV760CC	UXV760BC	UXV760AC	215)	UM00021S	UXV760BC	UXV760AC	216)	UCV761CQ	UXV760BC	UXV760AC
260)	217)	JBS-25AD	UM00022S	UXV760AC	218)	UXV760CC	UM00022S	UXV760AC	219)	UM00021S	UM00022S	UXV760AC
263)	220)	UCV761CQ	UM00022S	UXV760AC	221)	JBS-25AD	UCV761BQ	UXV760AC	222)	UXV760CC	UCV761BQ	UXV760AC
266)	223)	UM00021S	UCV761BQ	UXV760AC	224)	UCV761CQ	UCV761BQ	UXV760AC	225)	JBS-25AD	JBS-22AD	UM00023S
269)	226)	UXV760CC	JBS-22AD	UM00023S	227)	UM00021S	JBS-22AD	UM00023S	228)	UCV761CQ	JBS-22AD	UM00023S
272)	229)	JBS-25AD	UXV760BC	UM00023S	230)	UXV760CC	UXV760BC	UM00023S	231)	UM00021S	UXV760BC	UM00023S
275)	232)	UCV761CQ	UXV760BC	UM00023S	233)	JBS-25AD	UM00022S	UM00023S	234)	UXV760CC	UM00022S	UM00023S
278)	235)	UM00021S	UM00022S	UM00023S	236)	UCV761CQ	UM00022S	UM00023S	237)	JBS-25AD	UCV761BQ	UM00023S
281)	238)	UXV760CC	UCV761BQ	UM00023S	239)	UM00021S	UCV761BQ	UM00023S	240)	UCV761CQ	UCV761BQ	UM00023S
284)	241)	JBS-25AD	JBS-22AD	UCV761AQ	242)	UXV760CC	JBS-22AD	UCV761AQ	243)	UM00021S	JBS-22AD	UCV761AQ
287)	244)	UCV761CQ	JBS-22AD	UCV761AQ	245)	JBS-25AD	UXV760BC	UCV761AQ	246)	UXV760CC	UXV760BC	UCV761AQ
290)	247)	UM00021S	UXV760BC	UCV761AQ	248)	UCV761CQ	UXV760BC	UCV761AQ	249)	JBS-25AD	UM00022S	UCV761AQ
293)	250)	UCV760CC	UM00022S	UCV761AQ	251)	UM00021S	UM00022S	UCV761AQ	252)	UCV761CQ	UM00022S	UCV761AQ
296)	253)	JBS-25AD	UCV761BQ	UCV761AQ	254)	UXV760CC	UCV761BQ	UCV761AQ	255)	UM00021S	UCV761BQ	UCV761AQ
299)	256)	UCV761CQ	UCV761BQ	UCV761AQ	257)	UPM0022S	JBS-25AD	JBS-23AD	258)	UCC0022F	JBS-25AD	JBS-23AD
302)	259)	UXV762BC	JBS-25AD	JBS-23AD	260)	4BS-22AD	JBS-25AD	JBS-23AD	261)	UPM0022S	UXV760CC	JBS-23AD
305)	262)	UCC0022F	UXV760CC	JBS-23AD	263)	UXV762BC	UXV760CC	JBS-23AD	264)	4BS-22AD	UXV760CC	JBS-23AD
308)	265)	UPM0022S	UM00021S	JBS-23AD	266)	UCC0022F	UM00021S	JBS-23AD	267)	UXV762BC	UM00021S	JBS-23AD
311)	268)	4BS-22AD	UM00021S	JBS-23AD	269)	UPM0022S	UCV761CQ	JBS-23AD	270)	UCC0022F	UCV761CQ	JBS-23AD
314)	271)	UXV762BC	UCV761CQ	JBS-23AD	272)	4BS-22AD	UCV761CQ	JBS-23AD	273)	UPM0022S	JBS-25AD	UXV760AC
317)	274)	UCC0022F	JBS-25AD	UXV760AC	275)	UXV762BC	JBS-25AD	UXV760AC	276)	4BS-22AD	JBS-25AD	UXV760AC
320)	277)	UPM0022S	UXV760CC	UXV760AC	278)	UCC0022F	UXV760CC	UXV760AC	279)	UXV762BC	UXV760CC	UXV760AC
323)	280)	4BS-22AD	UXV760CC	UXV760AC	281)	UPM0022S	UM00021S	UXV760AC	282)	UCC0022F	UM00021S	UXV760AC
326)	283)	UXV762BC	UM00021S	UXV760AC	384)	4BS022AD	UM00021S	UXV760AC	285)	UPM0022S	UCV761CQ	UXV760AC
329)	286)	UCC0022F	UCV761CQ	UXV760AC	287)	UXV762BC	UCV761CQ	UXV760AC	288)	4BS-22AD	UCV761CQ	UXV760AC
332)	289)	UPM0022S	JBS-25AD	UM00023S	290)	UCC0022F	JBS-25AD	UM00023S	291)	UXV762BC	JBS-25AD	UM00023S
335)	292)	4BS-22AD	JBS-25AD	UM00023S	293)	UPM0022S	UXV760CC	UM00023S	294)	UCC0022F	UXV760CC	UM00023S
338)	295)	UXV762BC	UXV760CC	UM00023S	296)	4BS-22AD	UXV760CC	UM00023S	297)	UPM0022S	UM00021S	UM00023S
341)	298)	UCC0022F	UM00021S	UM00023S	299)	UXV762BC	UM00021S	UM00023S	300)	4BS-22AD	UM00021S	UM00023S
344)	301)	UPM0022S	UCV761CQ	UM00023S	302)	UCC0022F	UCV761CQ	UM00023S	303)	UXV762BC	UCV761CQ	UM00023S
347)	304)	4BS-22AD	UCV761CQ	UM00023S	305)	UPM0022S	JBS-25AD	UCV761AQ	306)	UCC0022F	JBS-25AD	UCV761AQ
350)	307)	UXV762BC	JBS-25AD	UCV761AQ	308)	4BS-22AD	JBS-25AD	UCV761AQ	309)	UPM0022S	UXV760CC	UCV761AQ
353)	310)	UCC0022F	UXV760CC	UCV761AQ	311)	UXV762BC	UXV760CC	UCV761AQ	312)	4BS-22AD	UXV760CC	UCV761AQ
356)	313)	UPM0022S	UM00021S	UCV761AQ	314)	UCC0022F	UM00021S	UCV761AQ	315)	UXV762BC	UM00021S	UCV761AQ
359)	316)	4BS-22AD	UM00021S	UCV761AQ	317)	UPM0022S	UCV761CQ	UCV761AQ	318)	UCC0022F	UCV761CQ	UCV761AQ
362)	319)	UXV762BC	UCV761CQ	UCV761AQ	320)	4BS-22AD	UCV761CQ	UCV761AQ	321)	UPM0023S	UPM0021S	JBS-22AD
365)	322)	UCC0023F	UPM0021S	JBS-22AD	323)	UXV762AC	UPM0021S	JBS-22AD	324)	4BS-23AD	UPM0021S	JBS-22AD
368)	325)	UPM0023S	UCC0021F	JBS-22AD	326)	UCC0023F	UCC0021F	JBS-22AD	327)	UXV762AC	UCC0021F	JBS-22AD
371)	328)	4BS-23AD	UCC0021F	JBS-22AD	329)	UPM0023F	UXV762CC	JBS-22AD	330)	UCC0023F	UXV762CC	JBS-22AD
374)	331)	UXV762AC	UXV762CC	JBS-22AD	332)	4BS-23AD	UXV762CC	JBS-22AD	333)	UPM0023S	4BS-25AD	JBS-22AD

TABLE 1.5.2.3.7-4 (continued)

INDIAN POINT 2 MINIMAL CUTSETS FOR COMPONENT COOLING WATER SYSTEM

CUTSETS WITH 3 BASIC EVENTS.

377)	334)	UCC0023F	4BS-25AD	JBS-22AD	335)	UXV762AC	4BS-25AD	JBS-22AD	336)	4BS-23AD	4BS-25AD	JBS-22AD
380)	337)	UPM0023S	UPM0021S	UXV760BC	338)	UCC0023F	UPM0021S	UXV760BC	339)	UXV762AC	UPM0021S	UXV760BC
383)	340)	4BS-23AD	UPM0021S	UXV760BC	341)	UPM0023S	UCC0021F	UXV760BC	342)	UCC0023F	UCC0021F	UXV760BC
386)	343)	UXV762AC	UCC0021F	UXV760BC	344)	4BS-23AD	UCC0021F	UXV760BC	345)	UPM0023S	UXV762CC	UXV760BC
389)	346)	UCC0023F	UXV762CC	UXV760BC	347)	UXV762AC	UXV762CC	UXV760BC	348)	4BS-23AD	UXV762CC	UXV760BC
392)	349)	UPM0023S	4BS-25AD	UXV760BC	350)	UCC0023F	4BS-25AD	UXV760BC	351)	UXV762AC	4BS-25AD	UXV760BC
395)	352)	4BS-23AD	4BS-25AD	UXV760BC	353)	UPM0023S	UPM0021S	UM00022S	354)	UCC0023F	UPM0021S	UM00022S
398)	355)	UXV762AC	UPM0021S	UM00022S	356)	4BS-23AD	UPM0021S	UM00022S	357)	UPM0023S	UCC0021F	UM00022S
401)	358)	UCC0023F	UCC0021F	UM00022S	359)	UXV762AC	UCC0021F	UM00022S	360)	4BS-23AD	UCC0021F	UM00022S
404)	361)	UPM0023S	UXV762CC	UM00022S	362)	UCC0023F	UXV762CC	UM00022S	363)	UXV762AC	UXV762CC	UM00022S
407)	364)	4BS-23AD	UXV762CC	UM00022S	365)	UPM0023S	4BS-25AD	UM00022S	366)	UCC0023F	4BS-25AD	UM00022S
410)	367)	UXV762AC	4BS-25AD	UM00022S	368)	4BS-23AD	4BS-25AD	UM00022S	369)	UPM0023S	UPM0021S	UCV761BQ
413)	370)	UCC0023F	UPM0021S	UCV761BQ	371)	UXV762AC	UPM0021S	UCV761BQ	372)	4BS-23AD	UPM0021S	UCV761BQ
416)	373)	UPM0023S	UCC0021F	UCV761BQ	374)	UCC0023F	UCC0021F	UCV761BQ	375)	UXV762AC	UCC0021F	UCV761BQ
419)	376)	4BS-23AD	UCC0021F	UCV761BQ	377)	UPM0023S	UXV762CC	UCV761BQ	378)	UCC0023F	UXV762CC	UCV761BQ
422)	379)	UXV762AC	UXV762CC	UCV761BQ	380)	4BS-23AD	UXV762CC	UCV761BQ	381)	UPM0023S	4BS-25AD	UCV761BQ
425)	382)	UCC0023F	4BS-25AD	UCV761BQ	383)	UXV762AC	4BS-25AD	UCV761BQ	384)	4BS-23AD	4BS-25AD	UCV761BQ
428)	385)	UPM0021S	JBS-22AD	JBS-23AD	386)	UCC0021F	JBS-22AD	JBS-23AD	387)	UXV762CC	JBS-22AD	JBS-23AD
431)	388)	4BS-25AD	JBS-22AD	JBS-23AD	389)	UPM0021S	UXV760BC	JBS-23AD	390)	UCC0021F	UXV760BC	JBS-23AD
434)	391)	UXV762CC	UXV760BC	JBS-23AD	392)	4BS-25AD	UXV760BC	JBS-23AD	393)	UPM0021S	UM00022S	JBS-23AD
437)	394)	UCC0021F	UM00022S	JBS-23AD	395)	UXV762CC	UM00022S	JBS-23AD	396)	4BS-25AD	UM00022S	JBS-23AD
440)	397)	UPM0021S	UCV761BQ	JBS-23AD	398)	UCC0021F	UCV761BQ	JBS-23AD	399)	UXV762CC	UCV761BQ	JBS-23AD
443)	400)	4BS-25AD	UCV761BQ	JBS-23AD	401)	UPM0021S	JBS-22AD	UXV760AC	402)	UCC0021F	JBS-22AD	UXV760AC
446)	403)	UXV762CC	JBS-22AD	UXV760AC	404)	4BS-25AD	JBS-22AD	UXV760AC	405)	UPM0021S	UXV760BC	UXV760AC
449)	406)	UCC0021F	UXV760BC	UXV760AC	407)	UXV762CC	UXV760BC	UXV760AC	408)	4BS-25AD	UXV760BC	UXV760AC
452)	409)	UPM0021S	UM00022S	UXV760AC	410)	UCC0021F	UM00022S	UXV760AC	411)	UXV762CC	UM00022S	UXV762AC
455)	412)	4BS-25AD	UM00022S	UXV760AC	413)	UPM0021S	UCV761BQ	UXV760AC	414)	UCC0021F	UCV761BQ	UXV760AC
458)	415)	UXV762CC	UCV761BQ	UXV760AC	416)	4BS-25AD	UCV761BQ	UXV760AC	417)	UPM0021S	JBS-22AD	UM00023S
461)	418)	UCC0021F	JBS-22AD	UM00023S	419)	UXV762CC	JBS-22AD	UM00023S	420)	4BS-25AD	JBS-22AD	UM00023S
464)	421)	UPM0021S	UXV760BC	UM00023S	422)	UCC0021F	UXV760BC	UM00023S	423)	UXV762CC	UXV760BC	UM00023S
467)	424)	4BS-25AD	UXV760BC	UM00023S	425)	UPM0021S	UM00022S	UM00023S	426)	UCC0021F	UM00022S	UM00023S
470)	427)	UXV762CC	UM00022S	UM00023S	428)	4BS-25AD	UM00022S	UM00023S	429)	UPM0021S	UCV761BQ	UM00023S
473)	430)	UCC0021F	UCV761BQ	UM00023S	431)	UXV762CC	UCV761BQ	UM00023S	432)	4BS-25AD	UCV761BQ	UM00023S
476)	433)	UPM0021S	JBS-22AD	UCV761AQ	434)	UCC0021F	JBS-22AD	UCV761AQ	435)	UXV762CC	JBS-22AD	UCV761AQ
479)	436)	4BS-25AD	JBS-22AD	UCV761AQ	437)	UPM0021S	UXV760BC	UCV761AQ	438)	UCC0021F	UXV760BC	UCV761AQ
482)	439)	UXV762CC	UXV760BC	UCv761AQ	440)	4BS-25AD	UXV760BC	UCV761AQ	441)	UPM0021S	UM00022F	UCV761AQ
485)	442)	UCC0021F	UM00022S	UCV761AQ	443)	UXV762CC	UM00022S	UCV761AQ	444)	4BS-25AD	UM00022S	UCV761AQ
488)	445)	UPM0021S	UCV761BQ	UCV761AQ	446)	UCC0021F	UCV761BQ	UCV761AQ	447)	UXV762CC	UCV761BQ	UCV761AQ
491)	448)	4BS-25AD	UCV761BQ	UCV761AQ	449)	UPM0022S	UPM0021S	JBS-23AD	450)	UCC0022F	UPM0021S	JBS-23AD
494)	451)	UXV762BC	UPM0021S	JBS-23AQ	452)	4BS-22AD	UPM0021S	JBS-23AD	453)	UPM0022S	UCC0021F	JBS-23AD
497)	454)	UCC0022F	UCC0021F	JBS-23AD	455)	UXV762BC	UCC0021F	JBS-23AD	456)	4BS-22AD	UCC0021F	JBS-23AD
500)	457)	UPM0022F	UXV762CC	JBS-23AD	458)	UCC0022F	UXV762CC	JBS-23AD	459)	UXV762BC	UXV762CC	JBS-23AD
503)	460)	4BS-22AD	UXV762CC	JBS-23AD	461)	UPM0022S	4BS-25AD	JBS-23AD	462)	UCC0022F	4BS-25AD	JBS-23AD
506)	463)	UXV762BC	4BS-25AD	JBS-23AD	464)	4BS-22AD	4BS-25AD	JBS-23AD	465)	UPM0022S	UPM0021S	UXV760AC
509)	466)	UCC0022F	UPM0021S	UXV760AC	467)	UXV762BC	UPM0021S	UXV760AC	468	4BS-22AD	UPM0021S	UXV760AC
512)	469)	UPM0022S	UCC0021F	UXV760AC	470)	UCC0022F	UCC0021F	UXV760AC	471)	UXV762BC	UCC0021F	UXV760AC
515)	472)	4BS-22AD	UCC0021F	UXV760AC	473)	UPM0022S	UXV762CC	UXV760AC	474)	UCC0022F	UXV762CC	UXV760AC

TABLE 1.5.2.3.7-4 (continued)

INDIAN POINT 2 MINIMAL CUTSETS FOR COMPONENT COOLING WATER SYSTEM

CUTSETS WITH 3 BASIC EVENTS

518)	475)	UXV762BC	UXV762CC	UXV760AC	476)	4BS-22AD	UXV762CC	UXV760AC	477)	UPM0022S	4BS-25AD	UXV760AC
521)	478)	UCC0022F	4BS-25AD	UXV760AC	479)	UXV762BC	4BS-25AD	UXV760AC	480)	4BS-22AD	4BS-25AD	UXV760AC
524)	481)	UPM0022S	UPM0021S	UM00023S	482)	UCC0022F	UPM0021S	UM00023S	483)	UXV762BC	UPM0021S	UM00023S
527)	484)	4BS-22AD	UPM0021S	UM00023S	485)	UPM0022S	UCC0021F	UM00023S	486)	UCC0022F	UCC0021F	UM00023S
530)	487)	UXV762BC	UCC0021F	UM00023S	488)	4BS-22AD	UCC0021F	UM00023S	489)	UPM0022S	UXV762CC	UM00023S
533)	490)	UCC0022F	UXV762CC	UM00023S	491)	UXV762BC	UXV762CC	UM00023S	492)	4BS-22AD	UXV762CC	UM00023S
536)	493)	UPM0022S	4BS-25AD	UM00023S	494)	UCC0022F	4BS-25AD	UM00023S	495)	UXV762BC	4BS-25AD	UM00023S
539)	496)	4BS-22AD	4BS-25AD	UM00023S	497)	UPM0022S	UPM0021S	UCV761AQ	498)	UCC0022F	UPM0021S	UCV761AQ
542)	499)	UXV762BC	UPM0021S	UCV761AQ	500)	4BS-22AD	UPM0021S	UCV761AQ	501)	UPM0022S	UCC0021F	UCV761AQ
545)	502)	UCC0022F	UCC0021F	UCV761AQ	503)	UXV762BC	UCC0021F	UCV761AQ	504)	4BS-22AD	UCC0021F	UCV761AQ
548)	505)	UPM0022S	UXV762CC	UCV761AQ	506)	UCC0022F	UXV762CC	UCV761AQ	507)	UXV762BC	UXV762CC	UCV761AQ
551)	508)	4BS-22AD	UXV762CC	UCV761AQ	509)	UPM0022S	4BS-25AD	UCV761AQ	510)	UCC0022F	4BS-25AD	UCV761AQ
553)	511)	UXV762BC	4BS-25AD	UCV761AQ	512)	4BS-22AD	4BS-25AD	UCv761AQ				

TABLE 1.5.2.3.7-5

INDIAN POINT 2 SYSTEM EFFECTS OF PIPE FAILURE - COMPONENT COOLING SYSTEM

Pipe Section	Diameter (Inches)	System Failure	Potential for Other Systems Impact
1. Pump Discharge Header to Heat Exchanger 21	14	Yes	Systems cooled by CCS fail
2. Pump Discharge Header to Heat Exchanger 22	14	Yes	Systems cooled by CCS fail
3. Heat Exchanger 21 Outlet to Combined Header	14	Yes	Systems cooled by CCS fail
4. Heat Exchanger 22 Outlet to Combined Header	14	Yes	Systems cooled by CCS fail
5. CCS Supply Header	20	Yes	Systems cooled by CCS fail
6. CCS Supply Header	18	Yes	Systems cooled by CCS fail
7. CCS Supply Header	16	Yes	Systems cooled by CCS fail
8. CCS Supply Header to RHR Heat Exchanger 21	12	Yes	Systems cooled by CCS fail
9. CCS Supply Header to RHR Heat Exchanger 22	12	Yes	Systems cooled by CCS fail
10. CCS Outlet From RHR Heat Exchanger 21	12	Yes	Systems cooled by CCS fail
11. CCS Outlet From RHR Heat Exchanger 22	12	Yes	Systems cooled by CCS fail
12. CCS Return Header	16	Yes	Systems cooled by CCS fail
13. CCS Return Header	18	Yes	Systems cooled by CCS fail
14. CCS Return Header	20	Yes	Systems cooled by CCS fail
15. CCS Supply to RCPs and Excess Letdown Heat Exchanger	8	Yes	Systems cooled by CCS fail
16. RCP Return Line	8	Yes	Systems cooled by CCS fail
17. Supply SFP Heat Exchanger	8	Yes	Systems cooled by CCS fail
18. Return From SFP Heat Exchanger	8	Yes	Systems cooled by CCS fail

TABLE 1.5.2.3.7-6

INDIAN POINT 2 COMPONENT COOLING SYSTEM

Boundary Condition: Power Available at Buses 2A, 3A, 5A

Basic Events	Failure Data				System Effect	Failure Data (t = 24 hours)	
	Hourly		Demand				
	Mean	Variance	Mean	Variance		Mean	Variance
1. Single Events							
a. Surge tank failure	8.60×10^{-10}	6.00×10^{-17}	-	-	System failure	-	-
b. Manual valves (3)	2.22×10^{-7}	5.30×10^{-14}	-	-	System failure	-	-
c. Service water supply fails*	-	-	-	-	System failure	-	-
d. Piping failures (18)	1.55×10^{-8}	1.94×10^{-14}	-	-	System failure		
TOTAL	2.38×10^{-7}	5.68×10^{-14}			System failure	5.72×10^{-6}	3.27×10^{-11}
2. Heat Exchanger Trains							
a. Heat exchanger 22	1.14×10^{-6}	1.76×10^{-12}	-	-	Loss of single heat exchanger	-	-
b. Heat exchanger 21	1.29×10^{-6}	1.87×10^{-12}	-	-	Loss of single heat exchanger	-	-
TOTAL					System failure	1.96×10^{-9}	1.09×10^{-16}
3. Pump Trains							
a. Operating pump	2.31×10^{-6}	1.31×10^{-11}	-	-			
b. Standby pump	-	-	7.44×10^{-3}	2.66×10^{-6}			
c. Previously operating pump	-	-	7.36×10^{-3}	7.36×10^{-6}			
TOTAL					System failure	4.55×10^{-6}	2.58×10^{-11}
4. Test and Maintenance	(with pump trains)						
5. Human Error	**						
6. Common Cause	**						
7. Other	**						
SYSTEM TOTAL						1.03×10^{-5}	5.69×10^{-11}

*Service water shown for completeness only, quantified at the event tree.
**Negligibly small failure probability.

TABLE 1.5.2.3.7-6 (continued)

INDIAN POINT 2 COMPONENT COOLING SYSTEM

Boundary Condition: Loss of a Single 480V Bus

Basic Events	Failure Data				System Effect	Failure Data (t = 24 hours)	
	Hourly		Demand				
	Mean	Variance	Mean	Variance		Mean	Variance
1. Single Events							
a. Surge tank failure	8.60×10^{-10}	6.00×10^{-17}	-	-	System failure	-	-
b. Manual valves (3)	2.22×10^{-7}	5.30×10^{-14}	-	-	System failure	-	-
c. Service water supply fails*	-	-	-	-	System failure	-	-
d. Piping failures (18)	1.55×10^{-8}	1.94×10^{-14}	-	-	System failure		
TOTAL	2.38×10^{-7}	5.68×10^{-14}			System failure	5.72×10^{-6}	3.27×10^{-11}
2. Heat Exchanger Trains							
a. Heat exchanger 22	1.14×10^{-6}	1.76×10^{-12}	-	-	Loss of single heat exchanger	-	-
b. Heat exchanger 21	1.29×10^{-6}	1.87×10^{-12}	-	-	Loss of single heat exchanger	-	-
TOTAL					System failure	1.69×10^{-9}	4.90×10^{-17}
3. Pump Trains							
a. Operating pump	2.31×10^{-6}	1.34×10^{-11}	-	-			
b. Standby pump	-	-	7.44×10^{-3}	2.66×10^{-6}			
c. Previously operating pump	-	-	6.48×10^{-3}	7.36×10^{-6}			
TOTAL					System failure	6.02×10^{-4}	1.90×10^{-7}
4. Test and Maintenance	(with pump trains)						
5. Human Error	**						
6. Common Cause	**						
7. Other	**						
SYSTEM TOTAL						6.07×10^{-4}	1.90×10^{-7}

*Service water shown for completeness only, quantified at the event tree.
**Negligibly small failure probability.

TABLE 1.5.2.3.7-6 (continued)

INDIAN POINT 2 COMPONENT COOLING SYSTEM

Boundary Condition: Power Available at a Single 480V Bus

Basic Events	Failure Data				System Effect	Failure Data (t = 24 hours)	
	Hourly		Demand				
	Mean	Variance	Mean	Variance		Mean	Variance
1. Single Events							
a. Surge tank failure	8.60×10^{-10}	6.00×10^{-17}	-	-	System failure	-	-
b. Manual valve(s)	2.22×10^{-7}	5.30×10^{-14}	-	-	System failure	-	-
c. Service water supply fails*	-	-	-	-	System failure	-	-
d. Piping failures (18)	1.55×10^{-8}	1.94×10^{-14}	-	-	System failure		
TOTAL	2.38×10^{-7}	5.68×10^{-14}			System failure	5.72×10^{-6}	3.27×10^{-11}
2. Heat exchanger trains							
a. Heat exchanger 22	1.14×10^{-6}	1.76×10^{-12}	-	-	Loss of single heat exchanger	-	-
b. Heat exchanger 21	1.29×10^{-6}	1.87×10^{-12}	-	-	Loss of single heat exchanger	-	-
TOTAL					System failure	1.96×10^{-9}	1.09×10^{-16}
3. Pump trains							
a. Operating pump	2.31×10^{-6}	1.34×10^{-11}	-	-			
b. Standby pump	-	-	7.44×10^{-3}	2.66×10^{-6}			
c. Previously operating pump	-	-	6.48×10^{-3}	7.36×10^{-6}			
TOTAL					System failure	6.54×10^{-3}	6.95×10^{-6}
4. Test and Maintenance	(with pump trains)						
5. Human Error	**						
6. Common Cause	**						
7. Other	**						
SYSTEM TOTAL						6.54×10^{-3}	6.95×10^{-6}

*Service water shown for completeness only, quantified at the event tree.
**Negligibly small failure probability.

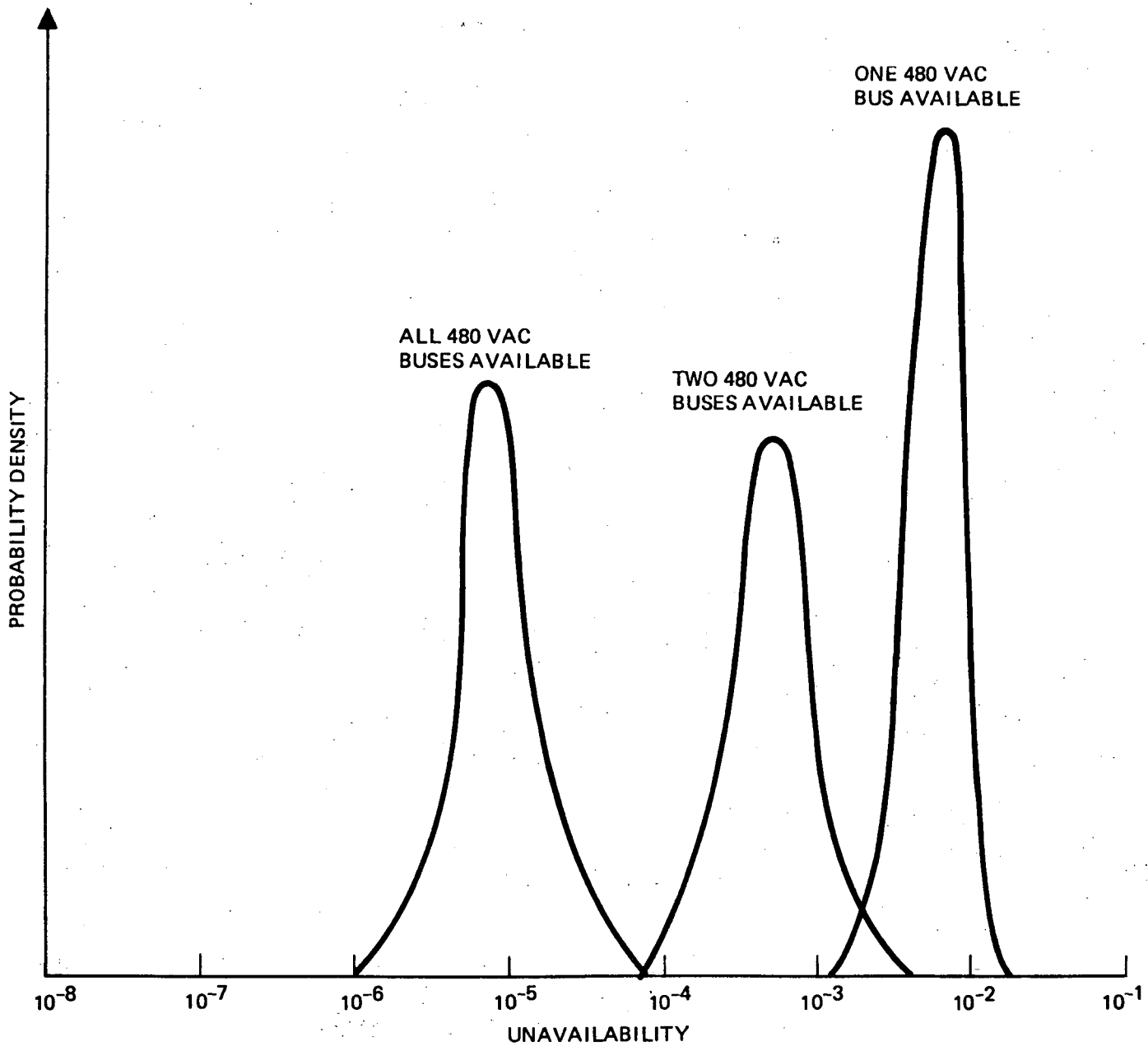


Figure 1.5.2.3.7-1. Probability Distribution of Indian Point 2 Component Cooling System Unavailability

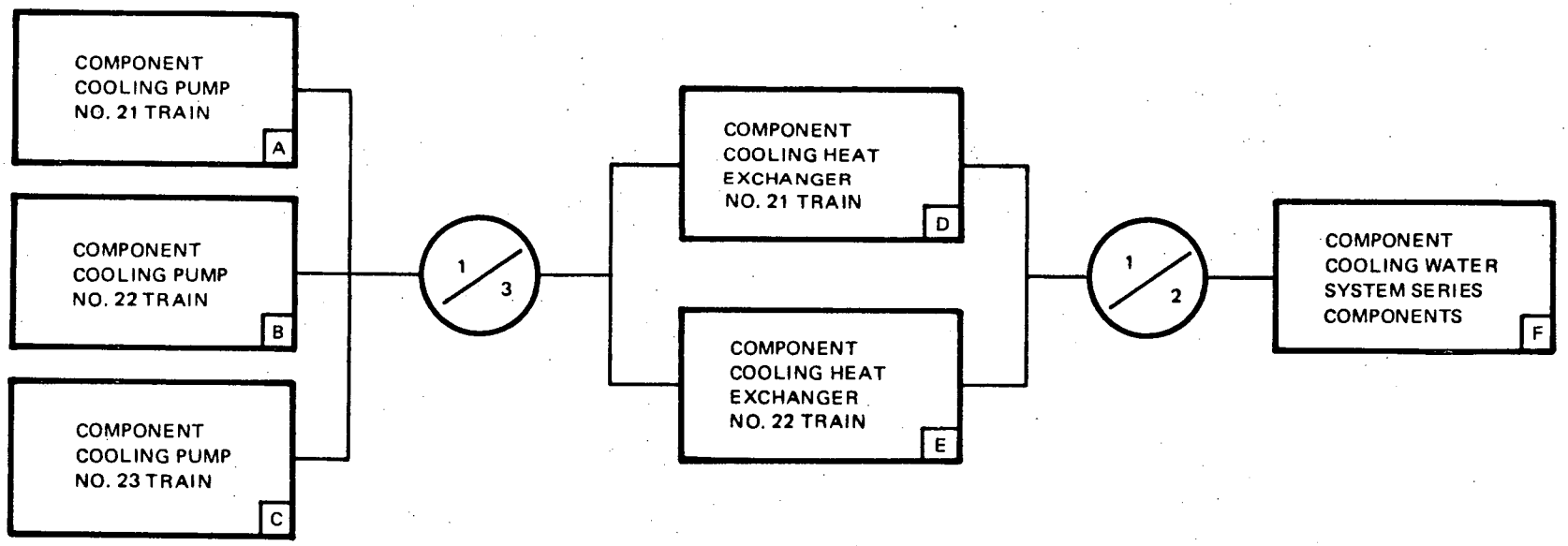


Figure 1.5.2.3.7-2. Indian Point 2 Component Cooling Water System Block Diagram

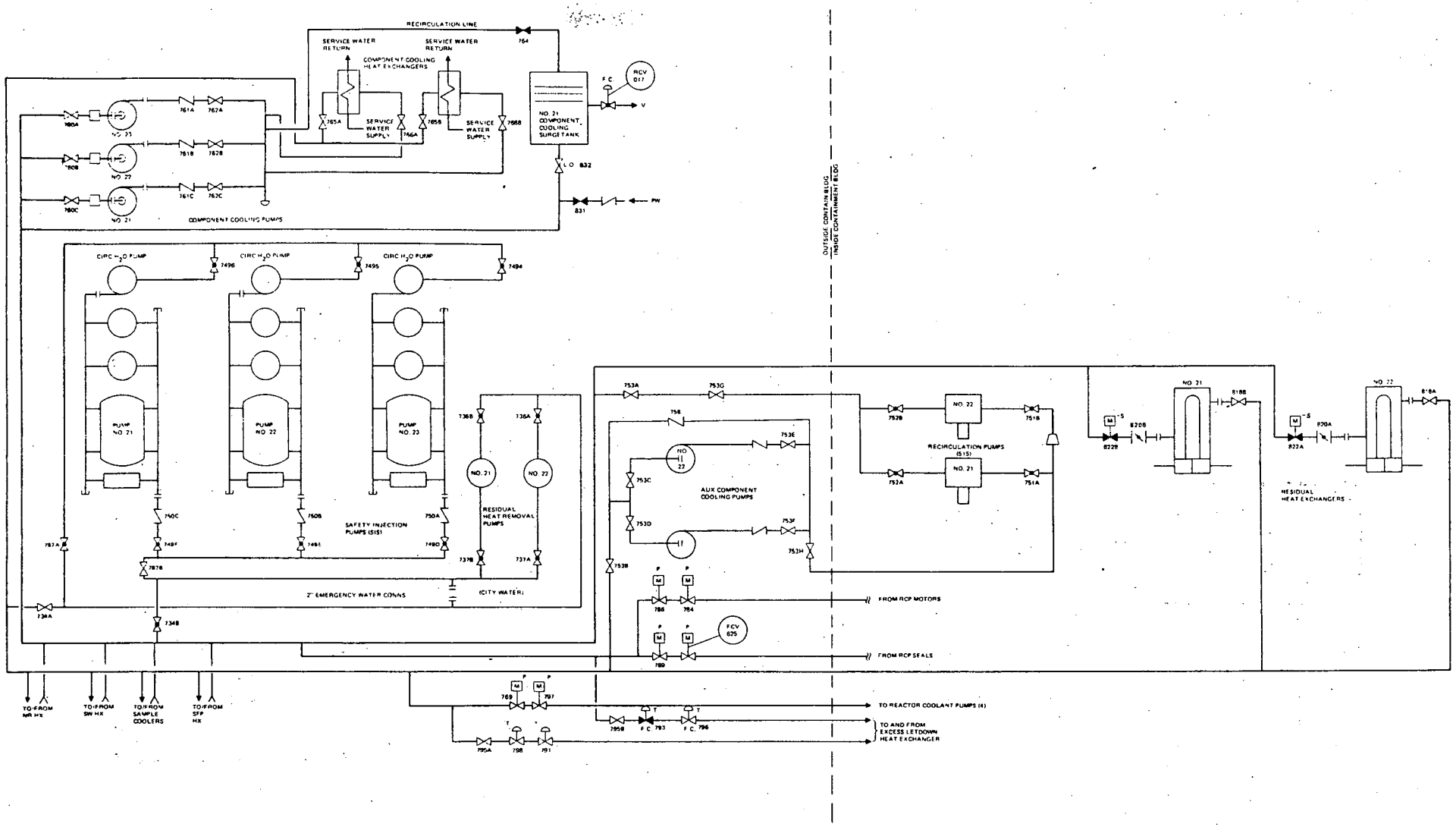
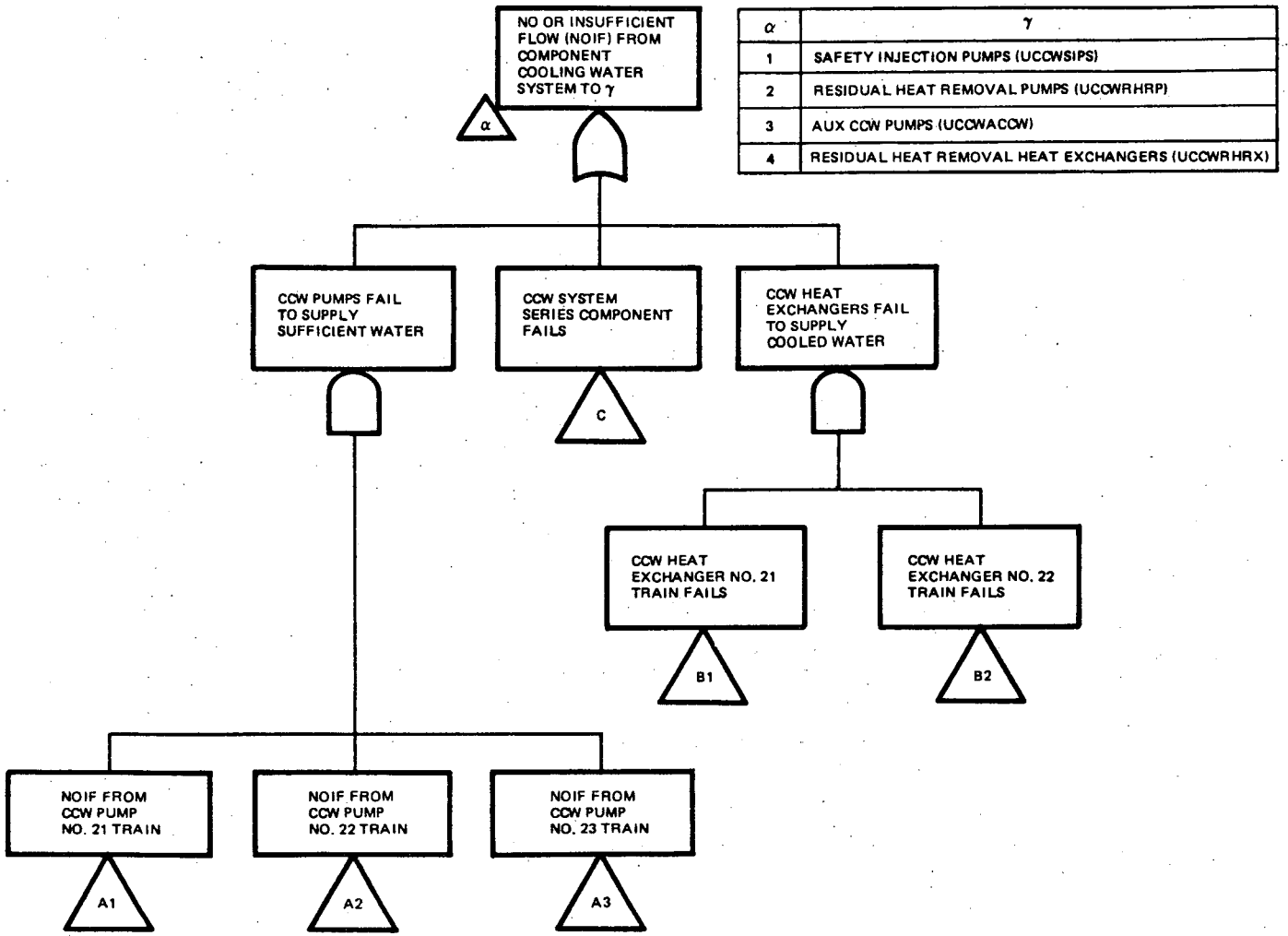
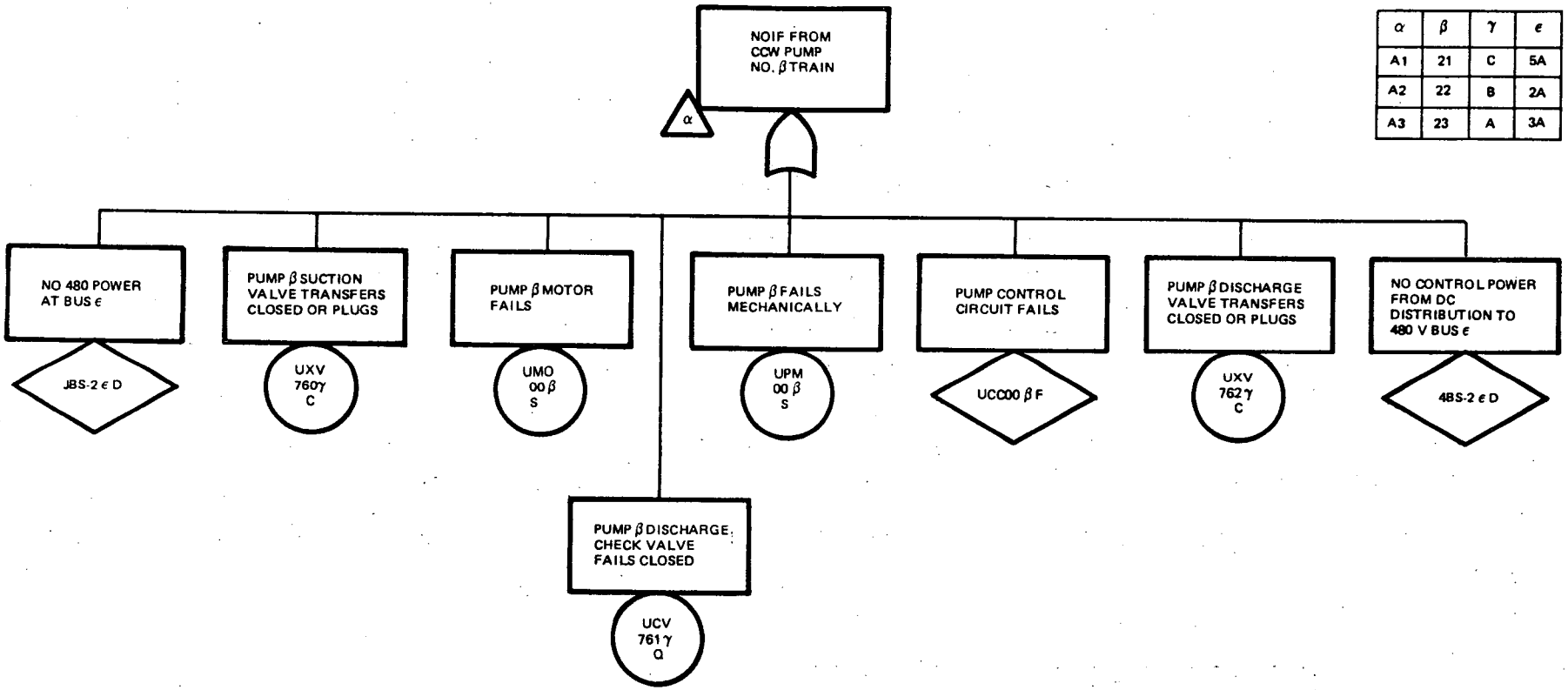


Figure 1.5.2.3.7-3. Indian Point 2 Component Cooling Water System



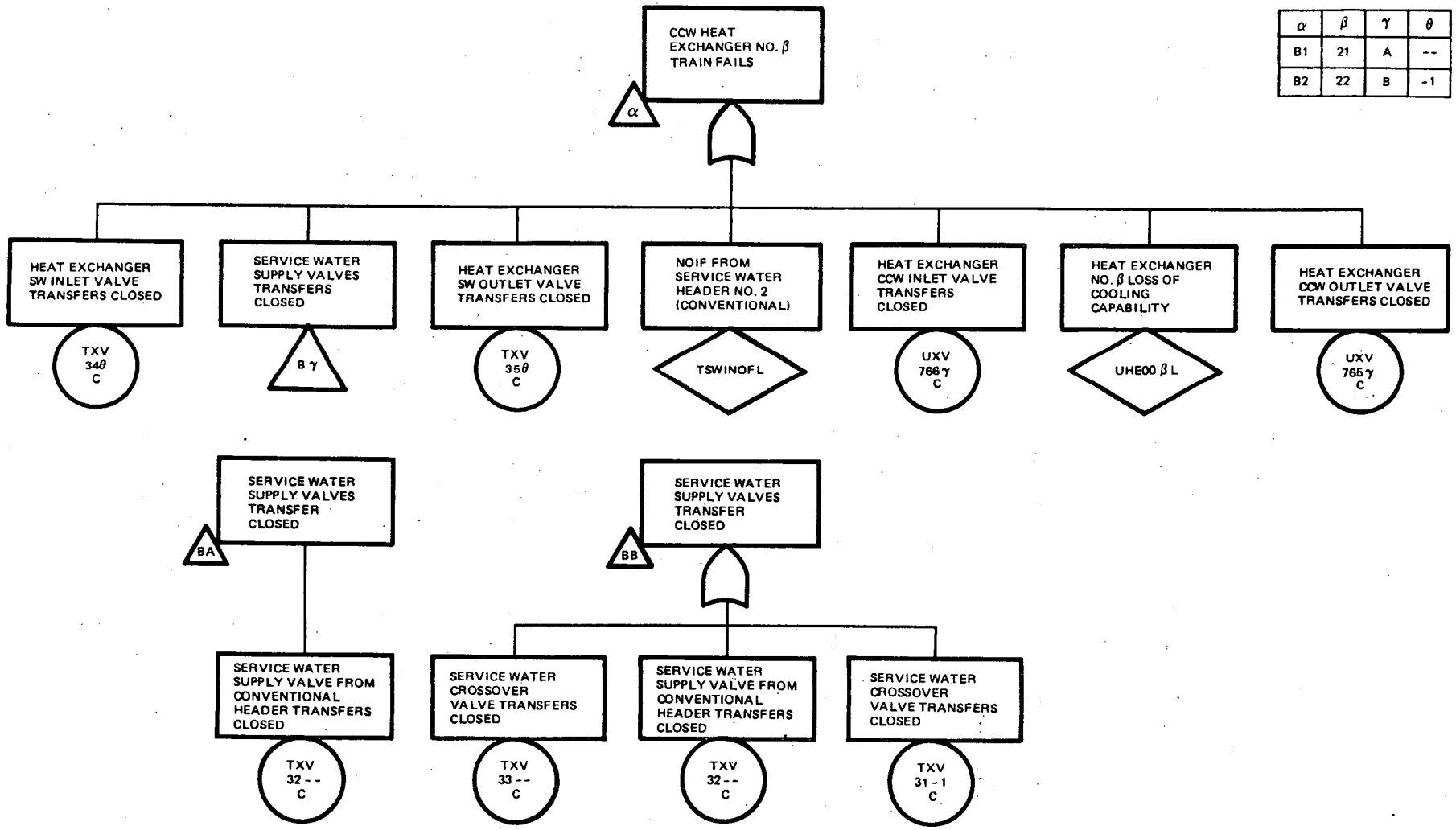
α	γ
1	SAFETY INJECTION PUMPS (UCCWSIPS)
2	RESIDUAL HEAT REMOVAL PUMPS (UCCWRHRP)
3	AUX CCW PUMPS (UCCWACCW)
4	RESIDUAL HEAT REMOVAL HEAT EXCHANGERS (UCCWRHRX)

Figure 1.5.2.3.7-4. Fault Tree Indian Point 2 Component Cooling Water System (Sheet 1 of 4)



α	β	γ	ε
A1	21	C	5A
A2	22	B	2A
A3	23	A	3A

Figure 1.5.2.3.7-4. (Sheet 2 of 4)



α	β	γ	θ
B1	21	A	--
B2	22	B	-1

Figure 1.5.2.3.7-4. (Sheet 3 of 4)

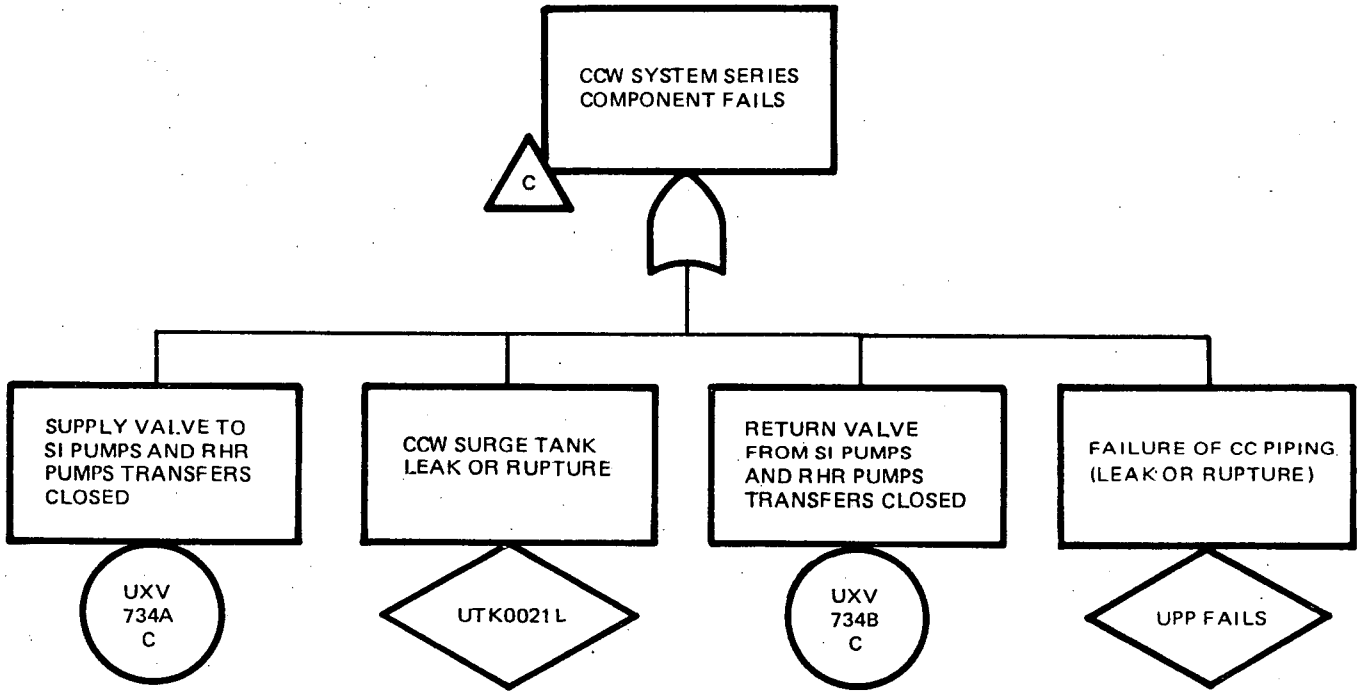


Figure 1.5.2.3.7-4. (Sheet 4 of 4)

1.5.2.3.8 Indian Point 2 Service Water System

1.5.2.3.8.1 Summary.

1.5.2.3.8.1.1 Introduction. The service water system (SWS) acts as a heat transport medium, removing heat from the components that it supplies and transferring this heat to the Hudson River. This system is needed to remove reactor decay heat under LOCA conditions and most transient events.

This analysis is carried out under the following conditions:

- The system is quantified to the first isolation valve capable of isolating a major component. In most cases, the component isolation valves are included with the components which are isolated. For example, the component cooling heat exchanger isolation valves are included with the component cooling heat exchangers in the component cooling system analysis.

- The system is analyzed as presently designed and maintained and includes modifications which will be performed to improve system reliability.

- Two service water pumps were supplying the nuclear header and two service water pumps were supplying the conventional header before the initiating event.

- Success of the system is defined as two service water pumps supplying the nuclear header for 24 hours after the initiating event and one service water pump supplying the conventional header for 24 hours after the initiating event.

1.5.2.3.8.1.2 Results. Table 1.5.2.3.8-1 summarizes the results of the SWS analysis. Three boundary conditions for electric power are analyzed: "Power at All 480V Buses," "Loss of Power at a Single 480V bus," and "Loss of Power at Two 480V Buses."

The analysis revealed the following dominant contributors to failure of the SWS to supply water for 24 hours:

	Mean
• Power at All 480V Buses	2.5×10^{-4}
- Random failure of the pumps selected to supply the nuclear header.	1.9×10^{-4} (75.8%)
- Test lineup error, failure to restore lineup after test, nuclear header.	3.3×10^{-5} (13.2%)
- Mispositioned mode selector switch.	1.1×10^{-5} (4.5%)

	Mean
• Loss of Power at a Single 480V Bus	1.9×10^{-2}
- Random failure of the pumps selected to supply the nuclear header.	1.8×10^{-2} (96.8%)
• Loss of Power at Two 480V Buses	1.0
- Failure of the pumps selected to supply the nuclear header due to insufficient power.	1.0 (100%)

No comparison is made to Reactor Safety Study (RSS) results as there is no comparable system analysis in the RSS.

1.5.2.3.8.1.3 Conclusions. The SWS is required to support plant operation and will be operating at the time of the initiating event. For this reason, the system is different from the plant standby emergency systems.

Failure of this system is dominated by the random failure of the pumps selected to supply the nuclear header. Probability distributions of system unavailability for the two states of electric power considered are shown in Figure 1.5.2.3.8-1.

1.5.2.3.8.2 System Description.

1.5.2.3.8.2.1 System Function. The SWS provides water from the Hudson River to various plant components that require heat removal for proper operation during normal and abnormal plant conditions.

This analysis was performed to determine the frequency of failure of the SWS to supply sufficient cooling water to the components required during abnormal plant operations. The components requiring service water during abnormal plant conditions are: three emergency diesel generators (EDGs); five containment building fan cooler recirculation cooling units (FCUs); and two component cooling heat exchangers.

The SWS consists of two groups of three pumps and two cooling water headers. One group of three pumps normally supplies essential plant services (the nuclear header) which for this analysis consists of the EDGs and the FCUs. The other group of three pumps supplies nonessential plant services (the conventional header), which include the component cooling heat exchangers. Each group of pumps can supply either conventional or nuclear plant services. Operator action is required to manually realign the system to change header services. The control room operator selects the pumps for nuclear services in the control room by shifting a mode selector switch. This switch places the three pumps selected in the engineered safeguards starting logic.

System failure is defined as "No or Insufficient Flow from the Service Water System." This may be further defined as the failure of two of three service water pumps selected for nuclear plant service to supply water to the nuclear services header, or the failure of one of three pumps selected for conventional plant service to supply water to the conventional services header.

1.5.2.3.8.2.2 System Diagrams. Figure 1.5.2.3.8-2 is a schematic block diagram representation of the SWS which depicts the system success requirements.

Figure 1.5.2.3.8-3* is a system functional diagram showing the basic system piping arrangements.

1.5.2.3.8.2.3 Service Water System and Operation.

1.5.2.3.8.2.3.1 Normal operation. The SWS consists of six identical vertical, centrifugal sump-type pumps rated at 5,000 gpm at 220 feet TDH. These pumps supply two independent supply headers. One header normally provides cooling water for the plant essential loads (nuclear header); the other header provides cooling water for the plant nonessential loads (conventional header).

*The configuration of the SWS in Figure 1.5.2.3.8-3 is based upon Consolidated Edison's modification commitments for the SWS.

During normal operation, the essential cooling loads are supplied by two of the three service water pumps aligned to provide nuclear plant services while the nonessential loads are supplied by two of the three service water pumps aligned to provide conventional plant services. During plant emergency conditions, any two of the three service water pumps on the essential cooling header can supply all of the cooling water requirements for essential plant equipment, and any one of the three service water pumps on the nonessential header can supply all of the cooling loads for nonessential equipment.

The service water pumps supplying the essential cooling loads are selected for automatic starting during ESS actuation by means of a mode selector switch in the control room. This switch has two positions: "4, 5, 6" and "1, 2, 3." The "4, 5, 6" position closes contacts in the ESS actuation control circuits and opens contacts in the safety injection recirculation phase control circuits for service water pumps 24, 25, and 26. The opposite conditions exist for the service water pumps controlled by the position not selected (i.e., pumps 21, 22, and 23). The "1, 2, 3" position performs the same functions for service water pumps 21, 22, and 23 that the "4, 5, 6" position performs for service water pumps 24, 25, and 26. In this analysis, service water pumps 24, 25, and 26 are assumed to be selected to provide essential plant cooling loads.

The discharge of each service water pump passes through a self-washing, automatic blowdown strainer. These strainers remove particles greater than 1/8 inch in diameter from the service water flow stream. Cleaning and blowdown of the strainers is automatic in response to the following signals: every 24 hours the strainer is cleaned and blown down for 5 minutes; and whenever the dp across the strainer reaches 3 psid, the strainer is cleaned and blown down until the strainer dp is reduced to less than 3 psid. The strainer motors receive power from MCCs 26A and 26B which are the essential 480V MCCs for Indian Point 2.

Each service water pump discharges through a check valve and a normally open butterfly valve to its respective service water header. The butterfly valve is used to isolate a service water pump for maintenance. The check valve is used to prevent backflow through an idle service water pump.

The essential cooling header supplies the following systems and components:

- Containment building fan cooler recirculation unit's cooling coils.
- Containment building fan cooler recirculation unit's fan motor cooling coils.
- Instrument air compressors closed cooling system.
- Main boiler feed pump lube oil coolers.

- Main turbine oil coolers.
- Generator seal oil coolers.
- Emergency diesel generator cooling services.
- CCR air conditioning unit.
- Radiation sample mixing nozzle.
- Service water pump strainer blowdown.

The conventional header supplies the component cooling heat exchangers and various conventional plant loads.

The EDGs and the containment building FCUs have automatic valves which open in response to a safeguards actuation signal. A discussion of the operation of these valves follows:

- Service water for the EDGs provides lube oil cooling and jacket water cooling. Each diesel generator has a manual header supply isolation valve from both service water supply headers and a manual outlet isolation valve. The outlets from each diesel combine into a single outlet header and pass to a parallel flow control valve arrangement. These pneumatically operated valves maintain a total flow of 1,200 gpm through the EDGs. In the event of a high diesel generator jacket water temperature or a safeguards actuation signal, the air to the flow control valves is vented from the controller and the valves go to the full open position.

- The SWS supplies cooling water to the five containment building FCUs. This water cools the air in the containment and the fan motors. The inlet and outlet isolation valves for each ventilation unit are located outside the containment building and may be operated either remotely or manually during abnormal plant conditions. The outlet line from each fan motor cooler is combined into a single header and passes through flow and temperature indicators. The outlet of the main cooling coils and the fan motor cooling coils is sampled for radioactivity by redundant radiation monitors. Flow through the fan motor coolers is maintained at approximately 55 gpm (total). The outlets from the FCU cooling coils are combined into a common outlet header. During normal plant operation, the service water flow from the coolers is throttled to maintain containment ambient temperature less than 120°F. Two parallel bypass valves around the temperature control valves TCV-1104 and TCV-1105 automatically open in response to a safeguards actuation signal. As these valves are pneumatically closed, loss of air or loss of power to the associated solenoid valve causes these bypass valves to open. The containment building FCU outlet valves are included with the containment fan cooler system description as failure of the valves to open does not result in SWS failure.

The service water pumps are located in a common well of the intake structure and take their suction from this well. The service water well receives river water through its own debris screen system and from either or both of the circulating water pump wells. The gates on the main circulating supply openings are normally closed and open automatically in response to a high dp across the debris screen or to an "Auto-Start" signal for the EDGs.

Table 1.5.2.3.8-2 lists the required flows for the SWS under various plant conditions. During normal operation, two nuclear service water pumps and two conventional service water pumps are required to support power operation. During LOCA conditions, two of the three nuclear service water pumps are required to start and run. After the shift from injection to recirculation, two nuclear service water pumps are required to continue running and one conventional service water pump is required to start and run.

1.5.2.3.8.2.3.2 System operation during emergency conditions. Three conditions of emergency operation of the SWS are discussed below. These are: "Unit Trip, No Blackout, No Safety Injection;" "Unit Trip, Blackout, No Safety Injection;" and "Unit Trip, Blackout, and Safety Injection.

1. Unit Trip, No Blackout, No Safety Injection. When the unit trips and no blackout or safety injection occurs, the system will remain in operation as it was before the event since all power requirements will have transferred from the unit auxiliary transformer to the station auxiliary transformer.

2. Unit Trip with Blackout and No Safety Injection. When this condition occurs, all service water pumps are tripped. Electrical power is reestablished using the EDGs, and the essential service water header is automatically reestablished in order to support the EDG cooling requirements. The operator then reestablishes the nonessential service water header to support the component cooling heat exchangers since a component cooling pump is automatically started. By reestablishing these headers, all other loads are then supplied with water as necessary.

3. Unit Trip with Blackout and Safety Injection. When this condition occurs, all service water pumps are tripped. Electrical power is reestablished using the EDGs. The ESS sequence signal then starts the service water pumps selected by the mode selector switch (right-hand safeguards panel) to supply the essential header.

   When active safety injection is completed and the recirculation phase is entered, two pumps (with outside power or three diesels running) or one pump (with only two of the diesels running) on the nonessential header will be started by recirculation phase switches RS-2 and RS-5. RS-2 will start one pump and RS-5 will start the other pump if three diesels are running or if outside power is available. Assuming that pumps 24, 25, and 26 were chosen for

essential loads and therefore essential service, then pumps 21, 22, and 23 would be used for the recirculation phase. Positioning switch RS-2 to "On" would start pump 21; if it failed to start, pump 22 would be started; and if 22 failed to start, pump 23 would be started. Switch RS-2 is independent of available power. Positioning switch RS-5 to "On" will cause the following action only if three diesels are running or outside power is available: pump 22 will be started; if pump 22 is running and pump 21 is not running, pump 21 is started; if pump 21 does not start, then pump 23 is started; and if pump 21 is running and pump 22 fails to start, pump 23 is started.

1.5.2.3.8.2.4 Instrumentation and Controls. The operator controls the service water pumps from the control room. In addition to the mode selector switch, which determines the service water pumps selected for automatic starting during the injection phase of an ESS actuation, the operator has individual pump breaker control switches at the cooling water and air panel. There are eight switches: one each for pumps 21, 23, 24, and 26, and two for pumps 22 and 25 (two sources of power for each pump). Each breaker control switch is spring-loaded to return to "Auto" from the "Stop" or "Start" positions and has four positions:

- Pull Out. The pump is disabled from starting by any automatic start signal. With the switch in this position, the "Safeguards Equipment Locked Open" alarm will be annunciated in the control room on the safeguards panel.

- Stop. The pump breaker is tripped open.

- Auto. The pump will be started for any one of the following conditions:

  - If selected for essential service, the pump will start after receipt of a safety injection signal or a unit trip with blackout and no safety injection signal.

  - If not selected for essential service, the pump will start when the recirculation phase switches are positioned for the blackout and safety injection condition. For the unit trip with blackout condition, operator action is necessary to start a nonessential service water pump.

- Start. The pump will be started.

While the pump is running, it may be tripped by:

- Placing the control switch to the Stop or Pull Out position.
- Overload.

The controls for the self-cleaning strainers are located at the intake structure, each strainer having its own control panel. Each panel has three switches: a disconnect switch which removes all power from the

unit; a three-position, "Off-Hand-Auto," condition of operation switch; and a two-position, "Intermittent-Continuous," mode of operation switch. A "Service Water Strainer Trouble" alarm is indicated in the control room if strainer is greater than 3 psid or if trouble has occurred to defeat the normal operation of the strainer motor.

During operation, pressure in the service water headers is monitored and an alarm is sounded in the control room if abnormally high or low. In addition, flow indicators and temperature detectors indicate the condition of the components served by the SWS.

1.5.2.3.8.2.5 Technical Specifications. The plant technical specifications require that three service water pumps on the designated essential header together with their associated piping and valves to be operable at all times. During power operation, if one of the three service water pumps on the designated essential header or any of the associated piping or valves is inoperable, the operator must immediately proceed to place in service an essential service water header which meets these requirements. If an essential service water header cannot be restored within 8 hours, the reactor is placed in a cold shutdown condition.

1.5.2.3.8.2.6 Testing and Maintenance.

1.5.2.3.8.2.6.1 Testing and surveillance. Monthly surveillance testing to satisfy the inservice inspection requirements of ASME Section XI is performed on the service water pumps. This testing is performed by recirculating water through the recirculation test line. During this test, the pump is isolated from its associated discharge header. Automatic starting of the service water pumps in response to a safety injection signal is performed every refueling cycle in conjunction with EDG tests.

Routine monitoring of the SWS is performed by the plant operators to determine system status.

1.5.2.3.8.2.6.2 Maintenance. Periodic maintenance is performed as required on the service water pumps and associated equipment. Because of the plant technical specification limits on the number of operable service water pumps on the nuclear header, periodic maintenance is not normally performed on a service water pump that is lined up to this header. Instead, the header services are shifted and the pump is taken out of service for maintenance. The periodic maintenance consists of ranging actions from cleaning and servicing the self-cleaning strainers to pump disassembly and seal replacement.

Maintenance plays a significant role in the pumps selected to supply the conventional header. During the recirculation phase of an accident sequence, one of three pumps must start and run to provide cooling for the component cooling heat exchangers. The plant technical specifications do not limit the out of service time for these pumps.

Based upon a review of plant data, the probability of a service water pump being out of service for maintenance is:

Mean: 6.95×10^{-2}

Variance: 2.69×10^{-4}

Upon the completion of pump train maintenance, testing is required to determine pump operability. At the completion of the testing, the pump is returned to its normal lineup.

1.5.2.3.8.2.7 Support Systems. The electric power system is required for operation of the SWS. Table 1.5.2.3.8-3 identifies the service water pumps and their electrical power supplies.

1.5.2.3.8.2.8 Operator Interaction with the Service Water System. Operator action or inaction can affect the operation of the SWS. As this system is required to support normal plant operation, most operator errors that affect system operation will be annunciated or indicated in the control room within a short time after their occurrence. These actions include shifting pump control to local (annunciated in the control room), inadvertently securing a running service water pump (annunciated and alarmed in the control room), and mispositioning manual valves which control service water flow to individual components or groups of components (annunciated or alarmed). Because of these reasons and because the SWS is required to be in operation to support plant operation, these types of human errors do not contribute to the failure of the SWS to start and continue running following an initiating event.

The operator may affect the automatic starting of the service water pumps selected to supply the nuclear services header by mispositioning the mode selector switch in the control room. This action results in the wrong set of service water pumps starting automatically in the event of a safeguards actuation or blackout condition. If uncorrected, this condition results in failure of the EDGs due to overheating. This condition is indicated immediately after ESS actuation by low flow alarms on the containment building FCUs and is followed shortly by low flow alarms and high temperatures on the EDGs. This condition is rapidly corrected in the control room by starting the required service water pumps and securing the misselected service water pumps. The mode selector switch must be returned to the correct position to allow subsequent restart of the service water pumps selected to the conventional header during the shift to recirculation.

From Table 20 and 21 of NUREG/CR-1278,* the error of omission while using a procedure with checkoff provisions is 0.001 (0.0001 - 0.005). Using the guidance presented in the Human Error Rates section of this report, the upper bound is taken as the 90th percentile value and the best estimate as the median value. This leads to the following

*Swain, A.D., and H.E. Guttmann, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," NUREG/CR-1278, Draft Report, April 1980.

distribution for the error of omission when written procedures are used in nonpassive tasks:

Mean: 2.20×10^{-3}

Variance 1.88×10^{-5}

The probability of not discovering this error (check list item, annunciated legend lamp) from Table 20-7 (Item 21) of NUREG/CR-1278 is 0.001 (0.0005-0.01). Again using the guidance presented in the Human Error Rates section, the upper bound (0.01) is taken as the 90th percentile value and the best estimate (0.001) as the median value. This leads to the following distribution for the probability of not discovering the mispositioned switch:

Mean: 5.04×10^{-3}

Variance: 6.21×10^{-4}

Combining the error of omission with the probability of not discovering the error, the frequency of occurrence for this mispositioned switch is obtained. The mean and variance for this event are:

Mean: 1.11×10^{-5}

Variance: 3.94×10^{-9}

Upon system actuation, the operator will receive immediate indication that system operation is incorrect (low flow alarms, etc.). However, the operator is also receiving numerous other indications and alarms. The operator could possibly pass over the first low flow alarms and miss the status of the SWS until diesel generator temperature alarms occur. At this point, with a loss of offsite power, system failure due to loss of electric power is imminent. For this analysis, system failure is assumed to occur.

1.5.2.3.8.2.9 Common Cause Analysis. The service water pumps are located in a common well of the intake structure. The intake structure and the SWS are designated as Seismic Class I. The breakers for the service water pumps are located at the 480V essential switchgear at Elevation 15' of the control building.

The manual valves for aligning the service water supplies to the various components served are located in common locations throughout the plant (i.e., diesel generator valves are located together, containment building supply valves are located together).

Common generic components in the SWS are manufactured by the same manufacturer; are subject to common maintenance, test, and operation procedures; and have common susceptibilities to secondary causes of failure (grit, moisture, vibration). Table 1.5.2.3.8-4 is a listing of the components included in the SWS analysis and the susceptibilities to the various categories of failure. Further discussion of the effect of common cause failures on system failure is presented in Section 1.5.2.3.8.4.6 of this analysis.

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1.5.2.3.8.3 System Modeling.

1.5.2.3.8.3.1 Event Trees. The top event for the SWS in the event trees for Indian Point 2 is "No or Insufficient Flow from the Service Water System" (NOIF). This is defined as failure of two pumps selected to supply the nuclear header to start or run, or failure of all three pumps selected to supply the conventional header to start or run. In the event trees, the SWS is included with the events concerning the containment fan coolers.

1.5.2.3.8.3.2 Fault Trees. Figure 1.5.2.3.8-4 presents the system fault tree developed for the Indian Point 2 SWS. NOIF is further defined as no or insufficient flow from service water header 1 (nuclear) or no flow from service water header 2 (conventional). For the purposes of this analysis, service water pumps 24, 25, and 26 are aligned to supply the nuclear header and pumps 21, 22, and 23 are aligned to supply the conventional header. The assumptions used in developing the fault tree are:

- Four pumps were in operation prior to the initiating event; two on the nuclear services header and two on the conventional services header.
- A safeguards actuation signal is present.
- The system is analyzed to the first valve which is capable of isolating a major component or group of components.
- System success requires that two pumps on the nuclear services header and one pump on the conventional services header operate for 24 hours.

1.5.2.3.8.3.3 Basic Event Coding. Table 1.5.2.3.8-4 presents the basic event coding used in the SWS analysis and the failure modes associated with these basic events. The failure data used in this analysis and the location and susceptibility coding for the basic events are also included.

1.5.2.3.8.3.4 Block Diagram. Figure 1.5.2.3.8-2 is the block diagram developed for the SWS. The components contained in each block of the diagram are:

- Block A - The service water intake consists of the service water screens and bypass gates.
- Block B - Service water pump 26 train consists of the following components:

TPMP26-S	Pump 26 fails mechanically (start or run).
TMOP26-S	Pump 26 motor fails (start or run).
TCCP26-F	Pump 26 control circuit fails.
JBS-26AD	No power from bus 6A.

4BS-SYSF	No DC control power at bus 6A.
TXVN2-5C	Pump discharge valve transfers closed.
TCVN1-5Q	Pump discharge check valve fails closed.
TFLSW45G	Strainer SWN-4-5 plugs.
TXJN3-5L	Expansion joint SWN-3-5 ruptures.
TXVN5010	Test valve, SWN-501, open.

- Block C - Service water pump 25 train consists of the following components:

TPMP25-S	Pump 25 fails mechanically (start or run).
TMOP25-S	Pump 25 motor fails (start or run).
TCCP25-F	Pump 25 control circuit fails.
JBS-23AD	No power from bus 3A or 2A.
4BS-SYSF	No DC control power at bus 3A or 2A.
TXVN2-4C	Pump discharge valve transfers closed.
TCVN1-4Q	Pump discharge check valve fails closed.
TFLSW44G	Strainer SWN-4-4 plugs.
TXJN3-4L	Expansion joint SWN-3-4 ruptures.
TXVN5020	Test valve, SWN-502, open..

- Block D - Service water pump 24 train consists of the following components:

TPMP24-S	Pump 24 fails mechanically (start or run).
TMOP24-S	Pump 24 motor fails (start or run).
TCCP24-F	Pump 24 control circuit fails.
JBS-25AD	No power from bus 5A.
4BS-SYSF	No DC control power at bus 5A.
TXVN2-3C	Pump discharge valve transfers closed.
TCVN1-3Q	Pump discharge check valve fails closed.
TFLSW43G	Strainer SWN-4-3 plugs.
TXJN3-3L	Expansion joint SWN-3-3 ruptures.
TXVN5030	Text valve, SWN-503, open.

- Block E - Service water pump 23 train consists of the following components:

TPMP23-S	Pump 23 fails mechanically (start or run).
TMOP23-S	Pump 23 motor fails (start or run).
TCCP23-F	Pump 23 control circuit fails.
JBS-26AD	No power from bus 6A.
4BS-SYSF	No DC control power at bus 6A.
TXVN2-2C	Pump discharge valve transfers closed.
TCVN1-2Q	Pump discharge check valve fails closed.
TFLSW42G	Strainer SWN-4-2 plugs.
TXJN3-2L	Expansion joint SWN-3-2 ruptures.
TXVN5040	Test valve, SWN-504, open.

- Block F - Service water pump 22 train consists of the following components:

TPMP22-S	Pump 22 fails mechanically (start or run).
TMOP22-S	Pump 22 motor fails (start or run).
TCCP22-F	Pump 22 control circuit fails.
JBS-22AD	No power from bus 2A or 3A.
4BS-SYSF	No DC control power at bus 2A or 3A.
TXVN2-1C	Pump discharge valve transfers closed.
TCVN1-1Q	Pump discharge check valve fails closed.
TFLSW41G	Strainer SWN-4-1 plugs.
TXJN3-1L	Expansion joint SWN-3-1 ruptures.
TXVN5050	Test valve, SWN-505, open.

- Block G - Service water pump 21 train consists of the following components:

TPMP21-S	Pump 21 fails mechanically (start or run).
TMOP21-S	Pump 21 motor fails (start or run).
TCCP21-F	Pump 21 control circuit fails.
JBS-25AD	No power from bus 5A.
4BS-SYSF	No DC control power at bus 5A.
TXVN2--C	Pump discharge valve transfers closed.
TCVN1--Q	Pump discharge check valve fails closed.
TFLSW4-G	Strainer SWN-4 plugs.
TXJN3--L	Expansion joint SWN-3 ruptures.
TXVN5060	Test valve, SWN-506, open.

- Block H - The diesel generator outlet consists of the following component:

TFVS76-Q	FCV-1176 does not open.

- Block I - The diesel generator outlet consists of the following component:

TFVS76AQ	FCV-1176A does not open.

1.5.2.3.8.3.5 Cutsets. Table 1.5.2.3.8-5 presents the SWS minimal cutsets which lead directly to the top event of the fault tree.

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1.5.2.3.8.4 Quantification. Quantification of the SWS is based upon the block diagram in Figure 1.5.2.3.8-2. The components on these blocks are described in Section 1.5.2.3.8.3 of this analysis and are defined as a train for analytical purposes.

In the following sections, quantification of the nuclear header and conventional header contributions to system failure are presented separately. The results of the header analysis are combined to present the frequency of system failure.

1.5.2.3.8.4.1 Single Failures. Figure 1.5.2.3.8-2 shows service water intake (block A) as a single contributor to SWS failure. As failure of this train can fail the nuclear and conventional service water headers, this failure is treated as a single failure. Also included in block A are piping failures which can cause system failure after initiation. Both of these defined single events are discussed below:

1. Service Water Intake Failure. This consists of failures of the service water intake screen and two screen bypass gates. The frequency of plugging of a screen system is assigned a median of 1×10^{-5} per hour with an error factor of 10. Because the screen system was in operation before the initiating event and the failure mode of interest is plugging, this is a conservative value. Using this data, the following mean and variance for the frequency of a screen plugging per hour is obtained:

   Mean: 2.66×10^{-5}

   Variance: 4.32×10^{-9}

   The service water bypass gates open pneumatically and are designed to open on loss of power or on a diesel-generator start signal. Operating air for the bypass gates is supplied by the plant air system or from an air receiver. The frequency of failure of a single bypass gate is assigned the value for the frequency of failure of an air-operated valve on demand:

   Mean: 7.49×10^{-4}

   Variance: 4.01×10^{-7}

   For two gates in parallel, the following mean and variance is obtained:

   Mean: 9.44×10^{-7}

   Variance: 6.36×10^{-12}

   If the bypass gates fail to open, the service water screen must remain unplugged for the time of interest (24 hours). This results

in the following distribution for the probability of failure of the water supply system to time, t = 24 hours:

Mean: 6.03×10^{-10}

Variance: 9.54×10^{-18}

2. Pipe Failures. Table 1.5.2.3.8-6 identifies the system effects of pipe failure for various sections of pipe in the SWS. Failures in piping which is less than 8 inches in diameter are not presented. The table is presented in two sections: the nuclear header, which is the header supplied by pumps 24, 25, and 26; and the conventional header, which is supplied by pumps 21, 22, and 23. The recovery times presented in Table 1.5.2.3.8-6 are not included in the quantification of the effects of pipe failure.

The frequency of failure per hour of a single pipe section is:

Mean: 8.60×10^{-10}

Variance: 6.00×10^{-17}

For the nuclear header, Table 1.5.2.3.8-6 identifies 17 sections of pipe where rupture will cause immediate failure of the SWS. For the conventional header, Table 1.5.2.3.8-6 identifies 13 sections of pipe where rupture will cause immediate failure of the SWS. This results in the following distribution for the frequency of piping failure per hour for the nuclear and conventional service water headers:

Mean (nuclear): 1.46×10^{-8}

Variance: 1.24×10^{-14}

Mean (conventional): 1.12×10^{-8}

Variance: 7.25×10^{-15}

Piping failures during plant operation are immediately detectable and result in either plant shutdown or header realignment for repair. Only those piping failures which occur after the start of an initiating event are of interest to this analysis.

The time period of interest is the first 24 hours after the initiating event. This leads to the following distributions for failure of the nuclear or conventional service water headers due to system piping failures:

Mean (nuclear): 3.51×10^{-7}

Variance: 7.14×10^{-12}

Mean (conventional): 2.68×10^{-7}

Variance: 4.18×10^{-12}

1.5.2.3.8.4.2 Double Failures.

1.5.2.3.8.4.2.1 Nuclear header. Nuclear header double contributions to system failure consist of failure of two of the three pump trains and failure of the two diesel generator outlet flow control valves.

1. Service Water Pump Train, Block B. Section 1.5.2.3.8.3 of this analysis presents the components which are included in a single pump train. Table 1.5.2.3.8-4 identifies the failure rates associated with these components. The component failure data for a single pump train is:

	Mean	Variance
Pump Fails (on demand)	6.41×10^{-3}	7.78×10^{-6}
Pump Fails (per hour)	1.52×10^{-5}	2.09×10^{-10}
Motor Fails (with pump failure)	-	-
Control Circuit Fails (with pump failure)	-	-
Switchgear Bus Fails	*	-
Control Power to Switchgear Bus Fails	*	-
Expansion Joint Ruptures (per hour)	8.60×10^{-9}	6.00×10^{-15}
Discharge Strainer Plugs (per hour, with auto cleaning)	2.66×10^{-5}	4.32×10^{-9}
Discharge Check Valve Fails to Open (on demand)	7.02×10^{-5}	1.09×10^{-8}
Discharge Valve Transfers Closed (per hour)	7.40×10^{-8}	5.89×10^{-15}
Test Valve Transfers Open	1.99×10^{-8}	1.83×10^{-13}

Blocks C, D, E, F, and G consist of similar components.

For an operating pump train, the frequency of failure per hour is described by the following distribution (consisting of pump failure to continue running, expansion joint rupture, strainer plugging, test valve failing open, and discharge valve transferring closed):

Mean: 4.19×10^{-5}

Variance: 3.44×10^{-9}

*Shown for completeness only; quantified in the Electric Power Analysis.

For a time, t = 24 hours, the distribution for failure of an operating pump train is:

Mean: 1.01×10^{-3}

Variance: 1.98×10^{-6}

At Indian Point 2, all operating service water pumps are electrically stripped from the 480V switchgear buses upon receipt of a safety injection signal. The service water pumps selected for nuclear service will restart immediately if offsite electric power is available. With a loss of offsite power, they will restart when the associated 480V switchgear buses are energized from the EDGs.

The frequency of failure to start a previously running service water pump consists of: pump failure to start on demand; check valve failure to open on demand; expansion joint rupturing; test valve failing open; and discharge valve transferring closed. The test valve failing open, the expansion joint rupture and the discharge valve closure must have occurred while the pump was idle ($t \leq 1$ hour). The frequencies of failure for this time period for the expansion joint, test valve, and the discharge valve are:

Mean (expansion joint): 8.60×10^{-9}

Variance: 6.00×10^{-15}

Mean (test valve): 1.99×10^{-8}

Variance: 1.83×10^{-13}

Mean (discharge valve): 7.40×10^{-8}

Variance: 5.89×10^{-15}

For a single previously operating pump train, the frequency of failure on demand is:

Mean: 6.48×10^{-3}

Variance: 7.31×10^{-6}

Given a successful start, the service water pump must operate for 24 hours. The total frequency of failure (start and operate for 24 hours) for a single previously operating service water pump train is now:

Mean: 7.48×10^{-3}

Variance: 9.11×10^{-6}

During plant operation, one service water pump selected to supply the nuclear header will normally be in standby. For this pump, failure to start on demand and check valve failure to open on demand remain as is previously defined; however, the discharge valve, expansion joint, and test valve contributions to pump train failure on demand must be developed.

Plant procedures require routine testing of the service water pumps. Failure in either component could have occurred at any time during this period. The fault detection time for these failures is taken as one-half of the test interval. This results in the following distributions for the frequency of failure on demand of an expansion joint, the test valve, and the discharge valve:

Mean (expansion joint):	3.14×10^{-6}
Variance:	5.72×10^{-10}
Mean (test valve):	7.26×10^{-6}
Variance:	1.11×10^{-8}
Mean (discharge valve):	2.70×10^{-5}
Variance:	7.44×10^{-10}

This results in the following frequency of failure on demand for a single standby service water pump train:

Mean: 6.52×10^{-3}

Variance: 7.32×10^{-6}

Given a successful start, the pump must continue to run for 24 hours, which results in the following failure frequency for a standby service water pump train:

Mean: 7.52×10^{-3}

Variance: 9.13×10^{-6}

The following expression defines the frequency of failure for the service water pump trains selected to supply the nuclear service water header:

$$Q_{pumps} = P\,(NO\ TEST)\,[P(OP)^2 + 2 \times P(OP) \times P(STBY) + P(OP)^2 \times P(STBY)] + P(TEST)[2 \times P(OP) + P(OP)^2]$$

where

P(OP) = frequency of failure of a running (or previously running) pump to t = 24 hours

P(STBY) = frequency of failure of the standby pump to t = 24 hours.

P(TEST) = frequency of occurrence, service water pump testing

P(NO TEST) = 1 - P(TEST)

With power available at all 480V switchgear buses, the pump train's contribution to system failure for the pumps selected to the nuclear header is described by the following distribution:

Mean: 1.89×10^{-4}

Variance: 1.46×10^{-8}

2. Pump Check Valve Short Circuiting Failures. System failure could also occur in the nuclear header if one pump failed to start and the associated check valve failed to close. Under these conditions, flow from the operating service water pumps will be short circuited through the idle pump train, causing insufficient flow in the nuclear service water header and, by definition, system failure.

From the hardware failure data section of this report, the frequency of occurrence for a check valve failing to seat/excessive leakage is:

Mean: 2.06×10^{-6} Check Valve Fails to Seat Per Hour

Variance: 2.63×10^{-12}

All service water pumps are tested monthly, at which time failure of a check valve to close will be detected. Using one half of the test interval as the mean time to detection for failures of this type, the unavailability due to a single check valve failing open is:

Mean: 7.52×10^{-4}

Variance: 3.35×10^{-7}

The unavailability of the system for a single pump failing to start and coincident check valve failing open is:

Mean: 4.82×10^{-6}

Variance: 2.00×10^{-11}

There are two possible combinations for this failure mode involving either of the two previously operating service water pumps. The standby

service water pump discharge check valve is closed prior to the initiating event. The frequency of nuclear header failure due to the event, pump failing to start and discharge check valve failing to close, is now:

Mean: 9.64×10^{-6}

Variance: 8.02×10^{-4}

3. Diesel Generator outlet Flow Control Valves, Blocks H and I. Failure of valves FCV-1176 and FCV-1176A to open on demand or to remain open for 24 hours results in failure of all three EDGs. The frequency of a single valve not opening on demand is:

Mean: 7.49×10^{-4}

Variance: 4.01×10^{-7}

For two valves in parallel, the following distribution for the frequency of failure on demand is obtained:

Mean: 9.44×10^{-7}

Variance: 6.36×10^{-12}

1.5.2.3.8.4.2.2 Conventional header. There is no double failure contribution to conventional header failure as only one of three pump trains is required for system success.

1.5.2.3.8.4.3 Triple Failures.

1.5.2.3.8.4.3.1 Nuclear header. There is no triple failure contribution to nuclear header failure.

1.5.2.3.8.4.3.2 Conventional header. The contribution of triple failures to failure of the conventional header consists of failure of all three pump trains.

Upon receipt of a safety injection signal, the pumps selected to supply conventional plant services are stripped from their respective 480V switchgear buses. These pumps are not restarted until the recirculation phase of LOCA recovery. System success requires the start and operation of a single service water pump selected to supply conventional plant services.

The following expression defines the probability of failure for the service water pump trains selected to supply the conventional service water header:

$$Q_{pumps} = P(IS)[P(OP)^2 \times P(STBY)] + P(OS)[P(OP)^2]$$

where

P(OP) = frequency of failure of a previously running pump to t = 24 hours (from Section 1.5.2.3.8.4.2.1).

P(STBY) = frequency of failure of a standby pump to t = 24 hours (from Section 1.5.2.3.8.4.2.1).

P(IS) = frequency of having a standby pump 1 - P(OS).

P(OS) = frequency of maintenance of a service water pump (from Section 1.5.2.3.8.2.6.2).

The pump train contribution to system failure for the pumps selected to the conventional header, with power available at all 480V switchgear buses, is described by the following distribution:

Mean: 4.97×10^{-6}

Variance: 2.50×10^{-11}

1.5.2.3.8.4.4 Test and Maintenance Failures.

1.5.2.3.8.4.4.1 Nuclear header. The ASME Section XI testing performed monthly on the service water pumps requires closing the pump discharge valve, opening the test valve, and running the service water pump for a minimum of 15 minutes. The test is routinely performed during power operation, and during the test, the service water pump is not available to supply water to the associated header.

If the service water pump testing is assumed to last from 15 to 45 minutes a month, this test results in the following distribution for frequency of a service water pump being out of service for test.

Mean: 7.71×10^{-4}

Variance: 1.39×10^{-7}

Plant procedures and technical specifications restrict this testing to one pump train at a time.

The test contribution to system failure is included with the quantification of the nuclear pump train's effect on system failure. No credit is taken for operator action to restore a service water pump to service if the system is demanded during the period of time the pump is being tested. Human errors associated with this testing are discussed and quantified in Section 1.5.2.3.8.4.5.

1.5.2.3.8.4.4.2 Conventional header. The testing described above applies to the pumps selected to supply the conventional header also. By procedure, the testing is restricted to one train at a time and the effect of this testing is included in the quantification of failure of

the pumps selected to supply the nuclear header. Therefore, being out of service for testing is not included in the quantification of conventional header failure.

The maintenance contribution to system failure is included with the quantification of the conventional pump train's effect on system failure.

1.5.2.3.8.4.5 Human Interaction Failures.

1.5.2.3.8.4.5.1 Nuclear header. From Section 1.5.2.3.8.2.8, the operator error of omission and nondiscovery of the error resulted in the following distribution for the frequency of occurrence of a mispositioned mode selector switch:

Mean: 1.11×10^{-5}

Variance 3.94×10^{-9}

This failure results in failure of the SWS.

The routine testing of the service water pumps requires that the pump under test be isolated from the common discharge header. Failure to return the valve lineup to normal after test will result in failure of the associated pump train on demand.

The SWS requires the operation of two service water pumps on each header to support normal plant operation. Therefore, this failure can only affect the standby pump train in each header.

The frequency of occurrence for this event for a single pump is:

Mean: 2.20×10^{-3}

Variance: 1.88×10^{-5}

There is dependence between the individual test acts performed on the service water pumps. If the error is performed on one of the first two pumps on one header, the error will be discovered when the third pump is lined up for testing because there will be insufficient service water flow to support normal plant operation. Under this condition, the operator performing the test will be less likely to improperly restore the third pump to service. For conservatism, this effect is not included in the frequency of occurrence for this event.

The frequency of nuclear header pump failure with this condition existing is described by the following expression:

$$Q_{pumps} = P(\text{Operator Error}) \times 2 \times P(OP).$$

This results in the following distribution for the frequency of failure of the nuclear header pumps on demand:

Mean: 3.30×10^{-5}

Variance: 4.16×10^{-9}

1.5.2.3.8.4.5.2 Conventional header. The routine testing described above is also performed on the pumps selected to supply the conventional header. As the testing of all pumps is performed during the same time period, there is dependence between the tests performed on each header. This dependence would act to decrease the frequency of occurrence of mispositioned valves for the last pump tested for the reasons noted in Section 1.5.2.3.8.4.5.1. For conservatism, this effect is not included in the frequency of occurrence for this event.

The frequency of conventional header pump failure with this condition existing is described by the following expression:

$$Q_{pump} = P(\text{Operator Error}) \times P(OP)^2$$

This results in the following distribution for the frequency of failure of the conventional header pumps on demand:

Mean: 1.43×10^{-7}

Variance: 1.31×10^{-13}

The human error of failing to shift to the recirculation phase from the injection phase is analyzed in the recirculation system description.

1.5.2.3.8.4.6 Common Cause Failures. Although there are many similar components sharing common locations in the SWS, a large portion of the components are not susceptible to most common cause failure mechanisms because they perform a passive function. These items include manual valves, check valves, and piping. Active components of the system, the service water pumps, are more likely candidates for common cause failure and are discussed below. External events such as earthquakes and flooding are discussed elsewhere in this study.

1. Fire. The service water pumps are located at the screen well structure. The pumps are not enclosed, and the fire loading in the area is low (as defined in the "Review of the Indian Point Station Fire Protection Program"). No fires are postulated in this area that could disable all service water pumps.

2. Moisture. The service water pump motors are designed for outdoor service and are protected by design from the effects of moisture.

3. Grit. Due to the design of the service water pump motors and the location of the service water pumps, airborne grit is not included as a common cause failure mode for these pumps.

4. Other Causes. Other common cause susceptibilities, such as manufacturer and test and maintenance procedures, are possible contributors to common cause failure of the service water pumps. However, the plant test program, maintenance program, and technical specifications combine to: (1) aid in discovery of pump problems and (2) limit the effects of common cause failures. No quantification is performed for these causes of failure.

NOTE: The service water pump breakers are susceptible to the common cause failure mechanisms of fire, moisture, and grit due to their common location in the switchgear room. Quantification and discussion of these effects are presented elsewhere in this study because the entire plant could be affected.

1.5.2.3.8.4.7 System Failure. Failure of the SWS is defined as failure of the nuclear header or conventional header to supply sufficient water to time, t = 24 hours. The frequency of failure for each header is presented below. For each header, the contribution of the single events to system failure includes the frequency of failure of the water supply system. The frequency of system failure includes this event only once, which eliminates this slight double counting. The failure frequency for each header includes the following contributors: single, double, and triple event random hardware failures; test and maintenance failures (which are included with the triple event failures); human error which results in system failure; and the common cause contribution to system failure.

1. Nuclear Header Failure. The frequency of failure of the nuclear header is characterized by the following mean and variance:

Mean: αsingles + αdoubles + αT&M

+ αoperator error + αcommon cause + αother

$= 2.44 \times 10^{-4}$

Variance: 2.16×10^{-8}

2. Conventional Header Failure. The frequency of failure of the conventional header is characterized by the following mean and variance:

Mean: αsingles + αtriples + αT&M + αoperator error

+ αcommon cause + αother

$= 5.38 \times 10^{-6}$

Variance: 2.66×10^{-11}

3. System Failure. The frequency of failure of the SWS is made up of those failures in the two headers which result in header failure. For the boundary condition, power available at all 480V switchgear buses, the following is the distribution for the frequency of failure of the SWS to time, t = 24 hours:

Mean: 2.50×10^{-4}

Variance: 2.16×10^{-8}

1.5.2.3.8.5 System Quantification with Differing Boundary Conditions for Electric Power.

1.5.2.3.8.5.1 Loss of Power at a Single Bus. This condition is defined as loss of power to switchgear buses 5A and 6A, or 2A and 3A. Switchgear buses 2A and 3A are defined as a single bus because the pumps which receive power from buses 2A and 3A can receive power from either bus, and a single EDG supplies both buses.

The loss of power at the various switchgear buses only affects the number of service water pump trains available; all other contributions to system failure remain as stated in Section 1.5.2.3.8.4 of this analysis.

A previously operating service water pump is assumed to have been powered from the switchgear bus that is now unavailable. This is a conservative assumption in that it results in a higher frequency of failure for the pump trains. This assumption is used for all of the loss of power calculations which follow:

1. Effect on the Nuclear Header. The following expression defines the frequency of system failure due to pump train failures for the pumps selected to supply the nuclear header:

$$Q_{pumps} = P(OP) + P(1S) \times P(STBY) + P(TEST) + P(\text{Operator Error})$$

where P(OP), P(TEST), P(Operator Error), and P(STBY) remain as defined in Section 1.5.2.3.8.4 and P(1S) = 1 - [P(TEST) + P(Operator Error)].

This results in the following distribution for the frequency of header failure due to pump train failures:

Mean: 1.80×10^{-2}

Variance: 3.30×10^{-5}

The frequency of failure of the nuclear header, with a loss of power at a single 480V switchgear bus, is:

Mean: 1.80×10^{-2}

Variance: 3.29×10^{-5}

2. Effect on the Conventional Header. The following expression defines the frequency of header failure due to pump train failures for the pumps selected to supply the conventional header:

$$Q_{pumps} = P(1S)[P(OP) \times P(STBY)] + P(\text{Maintenance}) \times P(OP) + P(\text{Operator Error}) \times P(OP)$$

where

$$P(1S) = 1 - [P(\text{Maintenance}) + P(\text{Operator Error})]$$

and the remainder of the terms remain as previously defined.

This results in the following distribution for the frequency of header failure due to pump train failures:

Mean: 5.89×10^{-4}

Variance: 7.37×10^{-8}

The frequency of failure of the conventional header, with a loss of power at a single 480V switchgear bus, is:

Mean: 5.89×10^{-4}

Variance: 7.35×10^{-8}

3. Effect on the System. The frequency of system failure, given the loss of a single 480V switchgear bus, is:

Mean: 1.86×10^{-2}

Variance: 3.29×10^{-5}

1.5.2.3.8.5.2 Loss of Power at Two Buses. This condition is defined as loss of power to switchgear buses 5A and 6A, 5A, 2A, and 3A, or 6A, 2A and 3A. The discussion for buses 2A and 3A was presented in Section 1.5.2.3.8.4.1. The assumption concerning which buses are lost is modified as follows: the previously operating service water pumps are assumed to have been powered by the switchgear buses that are now unavailable.

1. Effect on the Nuclear Header. Loss of power to the combinations of switchgear buses identified above results in failure of the nuclear header due to insufficient flow.

2. Effect on the Conventional Header. Loss of power to the combinations of switchgear buses defined above leads to the following expression for the frequency of pump train failures which result in header failure.

$$Q_{pumps} = P(1S) \times P(\text{STBY}) + P(\text{Maintenance}) + P(\text{Operator Error}).$$

This results in the following distribution for the frequency of conventional header failure due to pump train failures:

Mean: 7.87×10^{-2}

Variance: 2.79×10^{-4}

The frequency of failure of the conventional header, with a loss of power at two 480V switchgear buses, is:

Mean: 7.87×10^{-2}

Variance: 2.79×10^{-4}

3. Effect on the System. The frequency of system failure given loss of two 480V switchgear buses is 1.0 due to the effect of this condition upon the nuclear header pumps.

Table 1.5.2.3.8-7 summarizes the results of the analyses by cause on the SWS for the different boundary conditions evaluated.

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1.5.2.3.8.6 Special Case.

For some transients of interest (nonSI), the SWS success requirements change from two pumps operating on the nuclear header to one pump operating on the nuclear header supplying the EDGs. Modifications under consideration on the SW return line from the FCUs will allow SW flow to be maintained to the EDGs without overloading a single operating SW pump.

For the all power available case, the nuclear pump success requirements under this condition is represented by the following equation:

$$Q_{pumps} = P(NO\ TEST)\ [\ P(OP)^2 \times P(STBY)] + P(TEST)\ [P(OP)^2]$$

Using the values presented in Section 1.5.2.3.8.4.2 of this report, the following distribution for failure of at least one service water pump to continue running on the nuclear header is:

Mean: 5.38×10^{-7}

Variance: 3.37×10^{-13}

This results in an unavailability of the nuclear header represented by the following distribution:

Mean: 4.60×10^{-5}

Variance: 7.41×10^{-9}

System failure under this condition is represented by the following distribution:

Mean: 5.14×10^{-5}

Variance: 7.44×10^{-9}

Under the condition, "Loss of No Power at One Bus," the unavailability of the pumps supplying the nuclear header is represented by the following equation using the same assumptions as in Section 1.5.2.3.8.5.1.

$$Q_{pumps} = P(1S)\ [P(OP) \times P(STBY)] + P(OP) + [P(TEST) + P(Operator\ Error)]$$

where P(1S) remains as defined in Section 1.5.2.3.8.5.1.

This results in the following distribution for the frequency of failure for the nuclear header due to pump train failures:

Mean: 7.83×10^{-5}

Variance: 2.50×10^{-9}

The frequency of failure of the nuclear header for this case under the condition "Loss of No Power at One Bus" is:

Mean: 9.07×10^{-5}

Variance: 6.24×10^{-9}

System failure for this case is:

Mean: 6.80×10^{-4}

Variance: 7.86×10^{-8}

For the case "Loss of Power at Two Buses," one nuclear pump can supply sufficient water to maintain EDG cooling. The frequency of failure of the nuclear pump, assuming the standby pump must start and operate, is:

Mean: 6.98×10^{-3}

Variance: 7.86×10^{-6}

Failure of the nuclear header is now

Mean: 6.99×10^{-3}

Variance: 7.85×10^{-6}

and system failure is

Mean: 8.57×10^{-2}

Variance: 2.84×10^{-4}

The analyses in this section are used in the plant event trees to allow the quantification of recovery from the loss of power at two buses. With only one service water pump running, sufficient service water is available to sustain operation of the running EDG and allow recovery of the other EDGs. This in turn allows operation of all ESS equipment for a nonSI transient if the EDGs can be restored to operation.

TABLE 1.5.2.3.8-1

INDIAN POINT 2 SERVICE WATER SYSTEM ANALYSIS - SUMMARY OF RESULTS

	Mean	Variance	5th Percentile	95th Percentile	Median	RSS
Boundary Condition: Power at All 480V Switchgear Buses						
A. Nuclear Header						
1. Single Events						
a. Piping	3.5×10^{-7}	7.1×10^{-12}	7.4×10^{-10}	9.0×10^{-7}	7.8×10^{-8}	No Comparable Analysis
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Double Events						
a. Pump Trains	1.9×10^{-4}	1.5×10^{-8}	6.1×10^{-5}	3.7×10^{-4}	1.5×10^{-4}	
b. EDG Flow Control Valves	9.4×10^{-7}	6.4×10^{-12}	2.0×10^{-8}	2.9×10^{-6}	2.4×10^{-7}	
c. Pump fails to start and check valve	9.6×10^{-6}	8.0×10^{-11}	1.6×10^{-6}	2.2×10^{-5}	6.4×10^{-6}	
3. Test	(with pump trains)					
4. Human Error						
a. Mispositioned Switch	1.1×10^{-5}	3.9×10^{-9}	2.0×10^{-8}	2.7×10^{-5}	1.1×10^{-6}	
b. Test Lineup Error	3.3×10^{-5}	4.2×10^{-9}	1.3×10^{-6}	9.8×10^{-5}	1.3×10^{-5}	
5. Common Cause and Other	*					
TOTAL	2.4×10^{-4}	2.2×10^{-8}	9.1×10^{-5}	4.6×10^{-4}	2.0×10^{-4}	
B. Conventional Header						
1. Single Events						
a. Piping	2.7×10^{-7}	4.2×10^{-12}	5.7×10^{-10}	6.8×10^{-7}	5.9×10^{-8}	
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Triple Events						
a. Pump Trains	5.0×10^{-6}	2.5×10^{-11}	8.9×10^{-7}	1.1×10^{-5}	3.2×10^{-6}	
3. Maintenance	(with pump trains)					
4. Human Error						
a. Test Lineup Error	1.4×10^{-7}	1.3×10^{-13}	3.5×10^{-9}	4.4×10^{-7}	4.3×10^{-8}	
5. Common Cause and Other	*					
TOTAL	5.4×10^{-6}	2.7×10^{-11}	1.1×10^{-6}	1.2×10^{-5}	3.6×10^{-6}	
C. System						
1. Single Events						
a. Piping	6.2×10^{-7}	2.2×10^{-11}	1.3×10^{-9}	1.6×10^{-6}	1.4×10^{-7}	
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Double Events						
a. Nuclear Pumps Trains	1.9×10^{-4}	1.5×10^{-8}	6.1×10^{-5}	3.7×10^{-4}	1.5×10^{-4}	
b. EDG Flow Control Valves	9.4×10^{-7}	6.4×10^{-12}	2.0×10^{-8}	2.9×10^{-6}	2.4×10^{-7}	
c. Pump fails to start and check valve	9.6×10^{-6}	8.0×10^{-11}	1.6×10^{-6}	2.2×10^{-5}	6.4×10^{-6}	
3. Triple Events						
a. Conventional Pump Trains	5.0×10^{-6}	2.5×10^{-11}	8.9×10^{-7}	1.1×10^{-5}	3.2×10^{-6}	
4. Test and Maintenance						
a. Test	(with nuclear pump trains)					
b. Maintenance	(with conventional pump trains)					
5. Human Error						
a. Mispositioned Switch	1.1×10^{-5}	3.9×10^{-9}	2.0×10^{-8}	2.7×10^{-5}	1.1×10^{-6}	
b. Test Lineup Error - nuclear	3.3×10^{-5}	4.2×10^{-9}	1.3×10^{-6}	9.8×10^{-5}	1.3×10^{-5}	
c. Test Lineup Error - conventional	1.4×10^{-7}	1.3×10^{-13}	3.5×10^{-9}	4.4×10^{-7}	4.3×10^{-8}	
6. Common Cause and Other	*					
SYSTEM TOTAL	2.5×10^{-4}	2.2×10^{-8}	9.6×10^{-5}	4.6×10^{-4}	2.0×10^{-4}	

* Negligible failure frequency.

TABLE 1.5.2.3.8-1 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM ANALYSIS - SUMMARY OF RESULTS

	Mean	Variance	5th Percentile	95th Percentile	Median	RSS
Boundary Condition: Power Lost at One 480V Switchgear Bus						
A. Nuclear Header						
1. Single Events						
a. Piping	3.5×10^{-7}	7.1×10^{-12}	7.4×10^{-10}	9.0×10^{-7}	7.8×10^{-8}	No Comparable Analysis
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Double Events						
a. Pump Trains	1.8×10^{-2}	3.3×10^{-5}	1.1×10^{-2}	2.6×10^{-2}	1.6×10^{-2}	
b. EDG Flow Control Valves	9.4×10^{-7}	6.4×10^{-12}	2.0×10^{-8}	2.9×10^{-6}	2.4×10^{-7}	
3. Test			(with pump trains)			
4. Human Error						
a. Mispositioned Switch	1.1×10^{-5}	3.9×10^{-9}	2.0×10^{-8}	2.7×10^{-5}	1.1×10^{-6}	
b. Test Lineup Error			(with pump trains)			
5. Common Cause and Other	*					
TOTAL	1.8×10^{-2}	3.3×10^{-5}	1.1×10^{-2}	2.6×10^{-2}	1.6×10^{-2}	
B. Conventional Header						
1. Single Events						
a. Piping	2.7×10^{-7}	4.2×10^{-12}	5.7×10^{-10}	6.8×10^{-7}	5.9×10^{-8}	
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Triple Events						
a. Pump Trains	5.9×10^{-4}	7.4×10^{-8}	2.5×10^{-4}	8.9×10^{-3}	5.0×10^{-4}	
3. Maintenance			(with pump trains)			
4. Human Error						
a. Test Lineup Error			(with pump trains)			
5. Common Cause and Other	*					
TOTAL	5.9×10^{-4}	7.3×10^{-8}	2.5×10^{-4}	1.0×10^{-3}	5.0×10^{-4}	
C. System						
1. Single Events						
a. Piping	6.2×10^{-7}	2.2×10^{-11}	1.3×10^{-9}	1.6×10^{-6}	1.4×10^{-7}	
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Double Events						
a. Nuclear Pump Trains	1.8×10^{-2}	3.3×10^{-5}	1.1×10^{-2}	2.6×10^{-2}	1.6×10^{-2}	
b. EDG Flow Control Valves	9.4×10^{-7}	6.4×10^{-12}	2.0×10^{-8}	2.9×10^{-6}	2.4×10^{-7}	
3. Triple Events						
a. Conventional Pump Trains	5.9×10^{-4}	7.4×10^{-8}	2.5×10^{-4}	8.9×10^{-4}	5.0×10^{-4}	
4. Test and Maintenance						
a. Test			(with nuclear pump trains)			
b. Maintenance			(with conventional pump trains)			
5. Human Error						
a. Mispositioned Switch	1.1×10^{-5}	3.9×10^{-9}	2.0×10^{-8}	2.7×10^{-5}	1.1×10^{-6}	
b. Test Lineup Error - nuclear			(with nuclear pump trains)			
c. Test Lineup Error - conventional			(with conventional pump trains)			
6. Common Cause and Other	*					
SYSTEM TOTAL	1.9×10^{-2}	3.3×10^{-5}	1.1×10^{-2}	2.7×10^{-2}	1.7×10^{-2}	

* Negligible failure frequency.
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TABLE 1.5.2.3.8-1 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM ANALYSIS - SUMMARY OF RESULTS

	Mean	Variance	5th Percentile	95th Percentile	Median	RSS
Boundary Condition: Power Lost at Two 480V Switchgear Buses						
A. Nuclear Header						
1. Single Events						
a. Piping	3.5×10^{-7}	7.1×10^{-12}	7.4×10^{-10}	9.0×10^{-7}	7.8×10^{-8}	No Comparable Analysis
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Double Events						
a. Pump Trains	1.0	-	-	-	-	
b. EDG Flow Control Valves	9.4×10^{-7}	6.4×10^{-12}	2.0×10^{-8}	2.9×10^{-6}	2.4×10^{-7}	
3. Test			(with pump trains)			
4. Human Error						
a. Mispositioned Switch	1.1×10^{-5}	3.9×10^{-9}	2.0×10^{-8}	2.7×10^{-5}	1.1×10^{-6}	
b. Test Lineup Error			(with pump trains)			
5. Common Cause and Other	*					
TOTAL	1.0	-	-	-	-	
B. Conventional Header						
1. Single Events						
a. Piping	2.7×10^{-7}	4.2×10^{-12}	5.7×10^{-10}	6.8×10^{-7}	5.9×10^{-8}	
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Triple Events						
a. Pump Trains	7.9×10^{-2}	2.8×10^{-4}	5.2×10^{-2}	1.1×10^{-1}	7.4×10^{-2}	
3. Maintenance			(with pump trains)			
4. Human Error						
a. Test Lineup Error			(with pump trains)			
5. Common Cause and Other	*					
TOTAL	7.9×10^{-2}	2.8×10^{-4}	5.2×10^{-2}	1.1×10^{-1}	7.4×10^{-2}	
C. System						
1. Single Events						
a. Piping	6.2×10^{-7}	2.2×10^{-11}	1.3×10^{-9}	1.6×10^{-6}	1.4×10^{-7}	
b. Water Supply	6.0×10^{-10}	9.5×10^{-18}	2.1×10^{-12}	1.6×10^{-9}	6.2×10^{-11}	
2. Double Events						
a. Nuclear Pump Trains	1.0	-	-	-	-	
b. EDG Flow Control Valves	9.4×10^{-7}	6.4×10^{-12}	2.0×10^{-8}	2.9×10^{-6}	2.4×10^{-7}	
3. Triple Events						
a. Conventional Pump Trains	7.9×10^{-2}	2.8×10^{-4}	5.2×10^{-2}	1.1×10^{-1}	7.4×10^{-2}	
4. Test and Maintenance						
a. Test			(with nuclear pump trains)			
b. Maintenance			(with conventional pump trains			
5. Human Error						
a. Mispositioned Switch	1.1×10^{-5}	3.9×10^{-9}	2.0×10^{-8}	2.7×10^{-5}	1.1×10^{-6}	
b. Test Lineup Error - nuclear			(with nuclear pump trains)			
c. Test Lineup Error - conventional			(with conventional pump trains)			
6. Common Cause and Other	*					
SYSTEM TOTAL	1.0	-	-	-	-	

* Negligible failure frequency.
0310P113081

TABLE 1.5.2.3.8-2A

INDIAN POINT 2 - FLOW REQUIREMENTS FOR THE SERVICE WATER SYSTEM

Service (number)	Design Flow Each (gpm)	Normal Flow Total (gpm)	Accident Flow Injection Phase (gpm)	Accident Flow Recirculation Phase (gpm)
Containment Cooling Coils (5)	2,000	2,850	10,000	6,000
Diesel Generators (3)	400	-	1,200	1,200
Turbine Oil Coolers (2)	550	1,100	1,100	-
Seal Oil Coolers and MBFP Oil Coolers	220	220	220	-
Radiation Sample Mixing Nozzle	80	80	80	80
Air Compressor Heat Exchanger (2)	65	65	65	65
Service Water Strainer Blowdown	100	100	100	100
Component Coolers (2)	3,500	7,000	-	3,500
CCR Air Conditioning Unit	75	75	75	75

Note: ( ) identifies the number of components served.

TABLE 1.5.2.3.8-2B

INDIAN POINT 2 - NUCLEAR SERVICE WATER HEADER FLOW REQUIREMENTS

Service (number)	Normal Flow (gpm)	Accident Flow Injection Phase (gpm)	Accident Flow Recirculation Phase (gpm)
Total Flows for Essential Service Headers	4,490	12,840	7,520
Number of Pumps Required	1	2	2
Required Pump Capacity	4,490	6,420	3,760

TABLE 1.5.2.3.8-3

INDIAN POINT 2 - ELECTRIC POWER INTERFACE

Service Water Pump	Power Supply	
21 22 23	Bus 5A Bus 2A or 3A Bus 6A	Normally selected for conventional services
24 25 26	Bus 5A Bus 3A or 2A Bus 6A	Normally selected for essential services

TABLE 1.5.2.3.8-4

INDIAN POINT 2 SERVICE WATER SYSTEM BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data				Common Cause Data		Comments
		Mean	H/D (hours/ demand)	Variance	Reference*	Location	Susceptibility	
No Power at Switchgear Bus 2A or 3A	JBS-22AD	-	-	-	-	Control Building El. 15'	See EP Analysis	See EP Analysis
No Power at Switchgear Bus 3A or 2A	JBS-23AD	-	-	-	-	Control Building El. 15'	See EP Analysis	See EP Analysis
No Power at Switchgear Bus 5A	JBS-25AD	-	-	-	-	Control Building El. 15'	See EP Analysis	See EP Analysis
No Power at Switchgear Bus 6A	JBS-26AD	-	-	-	-	Control Building El. 15'	See EP Analysis	See EP Analysis
No DC Control Power at Switchgear Bus 2A and 3A	4BS-SYSF	-	-	-	-	Control Building El. 15'	See EP Analysis	See EP Analysis
No DC Control Power at Switchgear Bus 3A and 2A	4BS-SYSF	-	-	-	-	Control Building El. 15'	See EP Analysis	See EP Analysis
No DC Control Power at Switchgear Bus 5A	4BS-SYSF	-	-	-	-	Control Building El. 15'	See EP Analysis	See EP Analysis
No DC Control Power at Switchgear Bus 6A	4BS-SYSF	-	-	-	-	Control Building El. 15'	See EP Analysis	See EP Analysis
SW Pump 21 Does Not Start Does Not Continue to Run	TPMP21-S	6.41×10^{-3} 1.52×10^{-5}	D H	7.78×10^{-6} 2.09×10^{-10}	11 17	Intake Well	I, V	
SW Pump 22 Does Not Start Does Not Continue to Run	TPMP22-S	6.41×10^{-3} 1.52×10^{-5}	D H	7.78×10^{-6} 2.09×10^{-10}	11 17	Intake Well	I, V	
SW Pump 23 Does Not Start Does Not Continue to Run	TPMP23-S	6.41×10^{-3} 1.52×10^{-5}	D H	7.78×10^{-6} 2.09×10^{-10}	11 17	Intake Well	I, V	
SW Pump 24 Does Not Start Does Not Continue to Run	TPMP24-S	6.41×10^{-3} 1.52×10^{-5}	D H	7.78×10^{-6} 2.09×10^{-10}	11 17	Intake Well	I, V	
SW Pump 25 Does Not Start Does Not Continue to Run	TPMP25-S	6.41×10^{-3} 1.52×10^{-5}	D H	7.78×10^{-6} 2.09×10^{-10}	11 17	Intake Well	I, V	
SW Pump 26 Does Not Start Does Not Continue to Run	TPMP26-S	6.41×10^{-3} 1.52×10^{-5}	D H	7.78×10^{-6} 2.09×10^{-10}	11 17	Intake Well	I, V	

*Refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.3.8-4 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data				Common Cause Data		Comments
		Mean	H/D (hours/demand)	Variance	Reference*	Location	Susceptibility	
SW Pump 21 Motor Does Not Start/Run	TMOP21-S	-	-	-	-	Intake Structure	I, V, M	With Pump
SW Pump 22 Motor Does Not Start/Run	TMOP22-S	-	-	-	-	Intake Structure	I, V, M	With Pump
SW Pump 23 Motor Does Not Start/Run	TMOP23-S	-	-	-	-	Intake Structure	I, V, M	With Pump
SW Pump 24 Motor Does Not Start/Run	TMOP24-S	-	-	-	-	Intake Structure	I, V, M	With Pump
SW Pump 25 Motor Does Not Start/Run	TMOP25-S	-	-	-	-	Intake Structure	I, V, M	With Pump
SW Pump 26 Motor Does Not Start/Run	TMOP26-S	-	-	-	-	Intake Structure	I, V, M	With Pump
SW Pump 21 Control Circuit Fails	TCCP21-F	-	-	-	-	Control Building	I, V, M	With Pump
SW Pump 22 Control Circuit Fails	TCCP22-F	-	-	-	-	Control Building	I, V, M	With Pump
SW Pump 23 Control Circuit Fails	TCCP23-F	-	-	-	-	Control Building	I, V, M	With Pump
SW Pump 24 Control Circuit Fails	TCCP24-F	-	-	-	-	Control Building	I, V, M	With Pump
SW Pump 25 Control Circuit Fails	TCCP25-F	-	-	-	-	Control Building	I, V, M	With Pump
SW Pump 26 Control Circuit Fails	TCCP26-F	-	-	-	-	Control Building	I, V, M	With Pump
Expansion Joint SWN-3 Ruptures	TXJN3--L	8.60×10^{-9}	H	6.00×10^{-15}	42	Intake Well	I, V	
Expansion Joint SWN-3-1 Ruptures	TXJN3-1L	8.60×10^{-9}	H	6.00×10^{-15}	42	Intake Well	I, V	
Expansion Joint SWN-3-2 Ruptures	TXJN3-2L	8.60×10^{-9}	H	6.00×10^{-15}	42	Intake Well	I, V	
Expansion Joint SWN-3-3 Ruptures	TXJN3-3L	8.60×10^{-9}	H	6.00×10^{-15}	42	Intake Well	I, V	
Expansion Joint SWN-3-4 Ruptures	TXJN3-4L	8.60×10^{-9}	H	6.00×10^{-15}	42	Intake Well	I, V	
Expansion Joint SWN-3-5 Ruptures	TXJN3-5L	8.60×10^{-9}	H	6.00×10^{-15}	42	Intake Well	I, V	

*Refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.3.8-4 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data				Common Cause Data		Comments
		Mean	H/D (hours/demand)	Variance	Reference*	Location	Susceptibility	
Check Valve SWN-1 Fails to Open	TCVN1--Q	7.02×10^{-5}	D	1.09×10^{-8}	3	Strainer Enclosure	I	
Check Valve SWN-1-1 Fails to Open	TCVN1-1Q	7.02×10^{-5}	D	1.09×10^{-8}	3	Strainer Enclosure	I	
Check Valve SWN-1-2 Fails to Open	TCVN1-2Q	7.02×10^{-5}	D	1.09×10^{-8}	3	Strainer Enclosure	I	
Check Valve SWN-1-3 Fails to Open	TCVN1-3Q	7.02×10^{-5}	D	1.09×10^{-8}	3	Strainer Enclosure	I	
Check Valve SWN-1-4 Fails to Open	TCVN1-4Q	7.02×10^{-5}	D	1.09×10^{-8}	3	Strainer Enclosure	I	
Check Valve SWN-1-5 Fails to Open	TCVN1-5Q	7.02×10^{-5}	D	1.09×10^{-8}	3	Strainer Enclosure	I	
Discharge Valve SWN-2 Transfers Closed	TXVN2--C	7.40×10^{-8}	H	5.89×10^{-15}	1	Strainer Enclosure	I	
Discharge Valve SWN-2-1 Transfers Closed	TXVN2-1C	7.40×10^{-8}	H	5.89×10^{-15}	1	Strainer Enclosure	I	
Discharge Valve SWN-2-2 Transfers Closed	TXVN2-2C	7.40×10^{-8}	H	5.89×10^{-15}	1	Strainer Enclosure	I	
Discharge Valve SWN-2-3 Transfers Closed	TXVN2-3C	7.40×10^{-8}	H	5.89×10^{-15}	1	Strainer Enclosure	I	
Discharge Valve SWN-2-4 Transfers Closed	TXVN2-4C	7.40×10^{-8}	H	5.89×10^{-15}	1	Strainer Enclosure	I	
Discharge Valve SWN-2-5 Transfers Closed	TXVN2-5C	7.40×10^{-8}	H	5.89×10^{-15}	1	Strainer Enclosure	I	
Discharge Strainer SWN-4-1 Plugged	TFLSW41G	2.66×10^{-5}	H	4.32×10^{-9}	-	Strainer Enclosure	I	Developed in Text
Discharge Strainer SWN-4-2 Plugged	TFLSW42G	2.66×10^{-5}	H	4.32×10^{-9}	-	Strainer Enclosure	I	Developed in Text
Discharge Strainer SWN-4-3 Plugged	TFLSW43G	2.66×10^{-5}	H	4.32×10^{-9}	-	Strainer Enclosure	I	Developed in Text
Discharge Strainer SWN-4-4 Plugged	TFLSW44G	2.66×10^{-5}	H	4.32×10^{-9}	-	Strainer Enclosure	I	Developed in Text
Discharge Strainer SWN-4-5 Plugged	TFLSW45G	2.66×10^{-5}	H	4.32×10^{-9}	-	Strainer Enclosure	I	Developed in Text

*Refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.3.8-4 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM BASIC EVENT DATA

Event Description and Failure Mode	Fault Tree Coding	Failure Data				Common Cause Data		Comments
		Mean	H/D (hours/ demand)	Variance	Reference*	Location	Susceptibility	
Discharge Strainer SWN-4-6 Plugged	TFLSW46G	2.66×10^{-5}	H	4.32×10^{-9}	-	Strainer Enclosure	I	Developed in Text
SWP Intake Screen 27 Plugged	TSLSW27G	2.66×10^{-5}	H	4.32×10^{-9}	-	Intake Well	I	Developed in Text
SW Bypass Gate 21 Fails to Open	TSLSW21G	7.49×10^{-4}	D	4.01×10^{-7}	8	Intake Well	I	
SW Bypass Gate 22 Fails to Open	TSLSW22G	7.49×10^{-4}	D	4.01×10^{-7}	8	Intake Well	I	
FCV 1176 Does Not Open	TFVS76-Q	7.49×10^{-4}	H	4.01×10^{-7}	8	DG Building	I, V	
FCV 1176A Does Not Open	TFVS76AQ	7.49×10^{-4}	D	4.01×10^{-7}	8	DG Building	I, V	
SW Piping Nuclear Fails	TPP1FAIL	8.60×10^{-10}	H	6.00×10^{-17}	43	Various	I	
SW Piping Conventional Fails	TPP2FAIL	8.60×10^{-10}	H	6.00×10^{-17}	43	Various	I	
Test Valve SWN-501 Open	TXVN5010	1.99×10^{-8}	H	1.83×10^{-13}	2	Intake Well	I	
Test Valve SWN-502 Open	TXVN5020	1.99×10^{-8}	H	1.83×10^{-13}	2	Intake Well	I	
Test Valve SWN-503 Open	TXVN5030	1.99×10^{-8}	H	1.83×10^{-13}	2	Intake Well	I	
Test Valve SWN-504 Open	TXVN5040	1.99×10^{-8}	H	1.83×10^{-13}	2	Intake Well	I	
Test Valve SWN-505 Open	TXVN5050	1.99×10^{-8}	H	1.83×10^{-13}	2	Intake Well	I	
Test Valve SWN-506 Open	TXVN5060	1.99×10^{-8}	H	1.83×10^{-13}	2	Intake Well	I	

*Refers to item numbers in the plant failure data section of this report.

TABLE 1.5.2.3.8-5

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH ONE BASIC EVENT

3) 1) TPP2FAIL 2) TPP1FAIL 3) 4BS-SYSF

CUTSETS WITH TWO BASIC EVENTS

7)	1)	TFVS76-Q	TFVS76AQ	2)	TCVN1-5Q	TCVN1-3Q	3)	TXVN2-5C	TCVN1-3Q	4)	TXJN3-5L	TCVN1-3Q
11)	5)	TFLSW46G	TCVN1-3Q	6)	TXVN5010	TCVN1-3Q	7)	TCVN1-5Q	TXVN2-3C	8)	TXVN2-5C	TXVN2-3C
15)	9)	TXJN3-5L	TXVN2-3C	10)	TFLSW46G	TXVN2-3C	11)	TXVN5010	TXVN2-3C	12)	TCVN1-5Q	TXJN3-3L
19)	13)	TXVN2-5C	TXJN3-3L	14)	TXJN3-5L	TXJN3-3L	15)	TFLSW46G	TXJN3-3L	16)	TXVN5010	TXJN3-3L
23)	17)	TCVN1-5Q	TFLSW44G	18)	TXVN2-5C	TFLSW44G	19)	TXJN3-5L	TFLSW44G	20)	TFLSW46G	TFLSW44G
27)	21)	TXVN5010	TFLSW44G	22)	TCVN1-5Q	TXVN5030	23)	TXVN2-5C	TXVN5030	24)	TXJN3-5L	TXVN5030
31)	25)	TFLSW46G	TXVN5030	26)	TXVN5010	TXVN5030	27)	TCVN1-5Q	TCVN1-4Q	28)	TXVN2-5C	TCVN1-4Q
35)	29)	TXJN3-5L	TCVN1-4Q	30)	TFLSW46G	TCVN1-4Q	31)	TXVN5010	TCVN1-4Q	32)	TCVN1-5Q	TXVN2-4C
39)	33)	TXVN2-5C	TXVN2-4C	34)	TXJN3-5L	TXVN2-4C	35)	TFLSW46G	TXVN2-4C	36)	TXVN5010	TXVN2-4C
43)	37)	TCVN1-5Q	TXJN3-4L	38)	TXVN2-5C	TXJN3-4L	39)	TXJN3-5L	TXJN3-4L	40)	TFLSW46G	TXJN3-4L
47)	41)	TXVN5010	TXJN3-4L	42)	TCVN1-5Q	TFLSW45G	43)	TXVN2-5C	TFLSW45G	44)	TXJN3-5L	TFLSW45G
51)	45)	TFLSW46G	TFLSW45G	46)	TXVN5010	TFLSW45G	47)	TCVN1-5Q	TXVN5020	48)	TXVN2-5C	TXVN5020
55)	49)	TXJN3-5L	TXVN5020	50)	TFLSW46G	TXVN5020	51)	TXVN5010	TXVN5020	52)	TCVN1-5Q	TCCP25-F
59)	53)	TXVN2-5C	TCCP25-F	54)	TXJN3-5L	TCCP25-F	55)	TFLSW46G	TCCP25-F	56)	TXVN5010	TCCP25-F
63)	57)	TCVN1-5Q	TPMP25-S	58)	TXVN2-5C	TPMP25-S	59)	TXJN3-5L	TPMP25-S	60)	TFLSW46G	TPMP25-S
67)	61)	TXVN5010	TPMP25-S	62)	TCVN1-5Q	TMOP25-S	63)	TXVN2-5C	TMOP25-S	64)	TXJN3-5L	TMOP25-S
71)	65)	TFLSW46G	TMOP25-S	66)	TXVN5010	TMOP25-S	67)	TCCP25-F	TPMP26-S	68)	TPMP25-S	TPMP26-S
75)	69)	TMOP25-S	TPMP26-S	70)	TCCP25-F	TMOP26-S	71)	TPMP25-S	TMOP26-S	72)	TMOP25-S	TMOP26-S
79)	73)	TCCP25-F	TCCP26-F	74)	TPMP25-S	TCCP26-F	75)	TMOP25-S	TCCP26-F	76)	TCVN1-4Q	TPMP26-S
83)	77)	TXVN2-4C	TPMP26-S	78)	TXJN3-4L	TPMP26-S	79)	TFLSW45G	TPMP26-S	80)	TXVN5020	TPMP26-S
87)	81)	TCVN1-4Q	TMOP26-S	82)	TXVN2-4C	TMOP26-S	83)	TXJN3-4L	TMOP26-S	84)	TFLSW45G	TMOP26-S
91)	85)	TXVN5020	TMOP26-S	86)	TCVN1-4Q	TCCP26-F	87)	TXVN2-4C	TCCP26-F	88)	TXJN3-4L	TCCP26-F
95)	89)	TFLSW45G	TCCP26-F	90)	TXVN5020	TCCP26-F	91)	TCVN1-5Q	TPMP24-S	92)	TXVN2-5C	TPMP24-S
99)	93)	TXJN3-5L	TPMP24-S	94)	TFLSW46G	TPMP24-S	95)	TXVN5010	TPMP24-S	96)	TCVN1-5Q	TMOP24-S
103)	97)	TXVN2-5C	TMOP24-S	98)	TXJN3-5L	TMOP24-S	99)	TFLSW46G	TMOP24-S	100)	TXVN5010	TMOP24-S
107)	101)	TCVN1-5Q	TCCP24-F	102)	TXVN2-5C	TCCP24-F	103)	TXJN3-5L	TCCP24-F	104)	TFLSW46G	TCCP24-F
111)	105)	TXVN5010	TCCP24-F	106)	TPMP24-S	TPMP26-S	107)	TMOP24-S	TPMP26-S	108)	TCCP24-F	TPMP26-S
115)	109)	TPMP24-S	TMOP26-S	110)	TMOP24-S	TMOP26-S	111)	TCCP24-F	TMOP26-S	112)	TPMP24-S	TCCP26-S
119)	113)	TMOP24-S	TCCP26-F	114)	TCCP24-F	TCCP26-F	115)	TCVN1-3Q	TPMP26-S	116)	TXVN2-3C	TPMP26-S

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH TWO BASIC EVENTS

123)	117)	TXJN3-3L	TPMP26-S	118)	TFLSW44G	TPMP26-S	119)	TXVN5030	TPMP26-S	120)	TCVN1-3Q	TMOP26-S
127)	121)	TXVN2-3C	TMOP26-S	122)	TXJN3-3L	TMOP26-S	123)	TFLSW44G	TMOP26-S	124)	TXVN5030	TMOP26-S
131)	125)	TCVN1-3Q	TCCP26-F	126)	TXVN2-3C	TCCP26-F	127)	TXJN3-3L	TCCP26-F	128)	TFLSW44G	TCCP26-F
135)	129)	TXVN5030	TCCP26-F	130)	TPMP24-S	TCVN1-4Q	131)	TMOP24-S	TCVN1-4Q	132)	TCCP24-F	TCVN1-4Q
139)	133)	TPMP24-S	TXVN2-4C	134)	TMOP24-S	TXVN2-4C	135)	TCCP24-F	TXVN2-4C	136)	TPMP24-S	TXJN3-4L
143)	137)	TMOP24-S	TXJN3-4L	138)	TCCP24-F	TXJN3-4L	139)	TPMP24-S	TFLSW45G	140)	TMOP24-S	TFLSW45G
147)	141)	TCCP24-F	TFLSW45G	142)	TPMP24-S	TXVN5020	143)	TMOP24-S	TXVN5020	144)	TCCP24-F	TXVN5020
151)	145)	TPMP24-S	TCCP25-F	146)	TMOP24-S	TCCP25-F	147)	TCCP24-F	TCCP25-F	148)	TPMP24-S	TPMP25-S
155)	149)	TMOP24-S	TPMP25-S	150)	TCCP24-F	TPMP25-S	151)	TPMP24-S	TMOP25-S	152)	TMOP24-S	TMOP25-S
159)	153)	TCCP24-F	TMOP25-S	154)	TCVN1-3Q	TCVN1-4Q	155)	TXVN2-3C	TCVN1-4Q	156)	TXJN3-3L	TCVN1-4Q
163)	157)	TFLSW44G	TCVN1-4Q	158)	TXVN5030	TCVN1-4Q	159)	TCVN1-3Q	TXVN2-4C	160)	TXVN2-3C	TXVN2-4C
167)	161)	TXJN3-3L	TXVN2-4C	162)	TFLSW44G	TXVN2-4C	163)	TXVN5030	TXVN2-4C	164)	TCVN1-3Q	TXJN3-4L
171)	165)	TXVN2-3C	TXJN3-4L	166)	TXJN3-3L	TXJN3-4L	167)	TFLSW44G	TXJN3-4L	168)	TXVN5030	TXJN3-4L
175)	169)	TCVN1-3Q	TFLSW45G	170)	TXVN2-3C	TFLSW45G	171)	TXJN3-3L	TFLSW45G	172)	TFLSW44G	TFLSW45G
179)	173)	TXVN5030	TFLSW45G	174)	TCVN1-3Q	TXVN5020	175)	TXVN2-3C	TXVN5020	176)	TXJN3-3L	TXVN5020
183)	177)	TFLSW44G	TXVN5020	178)	TXVN5030	TXVN5020	179)	TCVN1-3Q	TCCP25-F	180)	TXVN2-3C	TCCP25-F
187)	181)	TXJN3-3L	TCCP25-F	182)	TFLSW44G	TCCP25-F	183)	TXVN5030	TCCP25-F	184)	TCVN1-3Q	TPMP25-S
191)	185)	TXVN2-3C	TPMP25-S	186)	TXJN3-3L	TPMP25-S	187)	TFLSW44G	TPMP25-S	188)	TXVN5030	TPMP25-S
195)	189)	TCVN1-3Q	TMOP25-S	190)	TXVN2-3C	TMOP25-S	191)	TXJN3-3L	TMOP25-S	192)	TFLSW44G	TMOP25-S
199)	193)	TXVN5030	TMOP25-S	194)	TCCP25-F	JBS-26AD	195)	TPMP25-S	JBS-26AD	196)	TMOP25-S	JBS-26AD
203)	197)	TCVN1-4Q	JBS-26AD	198)	TXVN2-4C	JBS-26AD	199)	TXJN3-4L	JBS-26AD	200)	TFLSW45G	JBS-26AD
207)	201)	TXVN5020	JBS-26AD	202)	TPMP24-S	JBS-26AD	203)	TMOP24-S	JBS-26AD	204)	TCCP24-F	JBS-26AD
211)	205)	TCVN1-3Q	JBS-26AD	206)	TXVN2-3C	JBS-26AD	207)	TXJN3-3L	JBS-26AD	208)	TFLSW44G	JBS-26AD
215)	209)	TXVN5030	JBS-26AD	210)	TCVN1-5Q	JBS-25AD	211)	TXVN2-5C	JBS-25AD	212)	TXJN3-5L	JBS-25AD
219)	213)	TFLSW46G	JBS-25AD	214)	TXVN5010	JBS-25AD	215)	JBS-25AD	TPMP26-S	216)	JBS-25AD	TMOP26-S
223)	217)	JBS-25AD	TCCP26-F	218)	JBS-25AD	TCVN1-4Q	219)	JBS-25AD	TXVN2-4C	220)	JBS-25AD	TXJN3-4L
227)	221)	JBS-25AD	TFLSW45G	222)	JBS-25AD	TXVN5020	223)	JBS-25AD	TCCP25-F	224)	JBS-25AD	TPMP25-S
229)	225)	JBS-25AD	TMOP25-S	226)	JBS-25AD	JBS-26AD						

CUTSETS WITH THREE BASIC EVENTS

232)	1)	TSLSW21G	TSLSW27G	TSLSW22G	2)	TCVN1-2Q	TPMP21-S	TCVN1-1Q	3)	TXVN2-2C	TPMP21-S	TCVN1-1Q
235)	4)	TXJN3-2L	TPMP21-S	TCVN1-1Q	5)	TFLSW43G	TPMP21-S	TCVN1-1Q	6)	TXVN5040	TPMP21-S	TCVN1-1Q

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH THREE BASIC EVENTS

238)	7)	TCVN1-2Q	TMOP21-S	TCVN1-1Q	8)	TXVN2-2C	TMOP21-S	TCVN1-1Q	9)	TXJN3-2L	TMOP21-S	TCVN1-1Q
241)	10)	TFLSW43G	TMOP21-S	TCVN1-1Q	11)	TXVN5040	TMOP21-S	TCVN1-1Q	12)	TCVN1-2Q	TCCP21-F	TCVN1-1Q
244)	13)	TXVN2-2C	TCCP21-F	TCVN1-1Q	14)	TXJN3-2L	TCCP21-F	TCVN1-1Q	15)	TFLSW43G	TCCP21-F	TCVN1-1Q
247)	16)	TXVN5040	TCCP21-F	TCVN1-1Q	17)	TCVN1-2Q	TPMP21-S	TXVN2-1C	18)	TXVN2-2C	TPMP21-S	TXVN2-1C
250)	19)	TXJN3-2L	TPMP21-S	TXVN2-1C	20)	TFLSW43G	TPMP21-S	TXVN2-1C	21)	TXVN5040	TPMP21-S	TXVN2-1C
253)	22)	TCVN1-2Q	TMOP21-S	TXVN2-1C	23)	TXVN2-2C	TMOP21-S	TXVN2-1C	24)	TXJN3-2L	TMOP21-S	TXVN2-1C
256)	25)	TFLSW43G	TMOP21-S	TXVN2-1C	26)	TXVN5040	TMOP21-S	TXVN2-1C	27)	TCVN1-2Q	TCCP21-F	TXVN2-1C
259)	28)	TXVN2-2C	TCCP21-F	TXVN2-1C	29)	TXJN3-2L	TCCP21-F	TXVN2-1C	30)	TFLSW43G	TCCP21-F	TXVN2-1C
262)	31)	TXVN5040	TCCP21-F	TXVN2-1C	32)	TCVN1-2Q	TPMP21-S	TXJN3-1L	33)	TXVN2-2C	TPMP21-S	TXJN3-1L
265)	34)	TXJN3-2L	TPMP21-S	TXJN3-1L	35)	TFLSW43G	TPMP21-S	TXJN3-1L	36)	TXVN5040	TPMP21-S	TXJN3-1L
268)	37)	TCVN1-2Q	TMOP21-S	TXJN3-1L	38)	TXVN2-2C	TMOP21-S	TXJN3-1L	39)	TXJN3-2L	TMOP21-S	TXJN3-1L
271)	40)	TFLSW43G	TMOP21-S	TXJN3-1L	41)	TXVN5040	TMOP21-S	TXJN3-1L	42)	TCVN1-2Q	TCCP21-F	TXJN3-1L
274)	43)	TXVN2-2C	TCCP21-F	TXJN3-1L	44)	TXJN3-2L	TCCP21-F	TXJN3-1L	45)	TFLSW43G	TCCP21-F	TXJN3-1L
277)	46)	TXVN5040	TCCP21-F	TXJN3-1L	47)	TCVN1-2Q	TPMP21-S	TFLSW42G	48)	TXVN2-2C	TPMP21-S	TFLSW42G
280)	49)	TXJN3-2L	TPMP21-S	TFLSW42G	50)	TFLSW43G	TPMP21-S	TFLSW42G	51)	TXVN5040	TPMP21-S	TFLSW42G
283)	52)	TCVN1-2Q	TMOP21-S	TFLSW42G	53)	TXVN2-2C	TMOP21-S	TFLSW42G	54)	TXJN3-2L	TMOP21-S	TFLSW42G
286)	55)	TFLSW43G	TMOP21-S	TFLSW42G	56)	TXVN5040	TMOP21-S	TFLSW42G	57)	TCVN1-2Q	TCCP21-F	TFLSW42G
289)	58)	TXVN2-2C	TCCP21-F	TFLSW42G	59)	TXJN3-2L	TCCP21-F	TFLSW42G	60)	TFLSW43G	TCCP21-F	TFLSW42G
292)	61)	TXVN5040	TCCP21-F	TFLSW42G	62)	TCVN1-2Q	TPMP21-S	TXVN5050	63)	TXVN2-2C	TPMP21-S	TXVN5050
295)	64)	TXJN3-2L	TPMP21-S	TXVN5050	65)	TFLSW43G	TPMP21-S	TXVN5050	66)	TXVN5040	TPMP21-S	TXVN5050
298)	67)	TCVN1-2Q	TMOP21-S	TXVN5050	68)	TXVN2-2C	TMOP21-S	TXVN5050	69)	TXJN3-2L	TMOP21-S	TXVN5050
301)	70)	TFLSW43G	TMOP21-S	TXVN5050	71)	TXVN5040	TMOP21-S	TXVN5050	72)	TCVN1-2Q	TCCP21-F	TXVN5050
304)	73)	TXVN2-2C	TCCP21-F	TXVN5050	74)	TXJN3-2L	TCCP21-F	TXVN5050	75)	TFLSW43G	TCCP21-F	TXVN5050
307)	76)	TXVN5040	TCCP21-F	TXVN5050	77)	TCVN1-2Q	TPMP21-S	TCCP22-F	78)	TXVN2-2C	TPMP21-S	TCCP22-F
310)	79)	TXJN3-2L	TPMP21-S	TCCP22-F	80)	TFLSW43G	TPMP21-S	TCCP22-F	81)	TXVN5040	TPMP21-S	TCCP22-F
313)	82)	TCVN1-2Q	TMOP21-S	TCCP22-F	83)	TXVN2-2C	TMOP21-S	TCCP22-F	84)	TXJN3-2L	TMOP21-S	TCCP22-F
316)	85)	TFLSW43G	TMOP21-S	TCCP22-F	86)	TXVN5040	TMOP21-S	TCCP22-F	87)	TCVN1-2Q	TCCP21-F	TCCP22-F
319)	88)	TXVN2-2C	TCCP21-F	TCCP22-F	89)	TXJN3-2L	TCCP21-F	TCCP22-F	90)	TFLSW43G	TCCP21-F	TCCP22-F
322)	91)	TXVN5040	TCCP21-F	TCCP22-F	92)	TCVN1-2Q	TPMP21-S	TPMP22-S	93)	TXVN2-2C	TPMP21-S	TPMP22-S
325)	94)	TXJN3-2L	TPMP21-S	TPMP22-S	95)	TFLSW43G	TPMP21-S	TPMP22-S	96)	TXVN5040	TPMP21-S	TPMP22-S
328)	97)	TCVN1-2Q	TMOP21-S	TPMP22-S	98)	TXVN2-2C	TMOP21-S	TPMP22-S	99)	TXJN3-2L	TMOP21-S	TPMP22-S
331)	100)	TFLSW43G	TMOP21-S	TPMP22-S	101)	TXVN5040	TMOP21-S	TPMP22-S	102)	TCVN1-2Q	TCCP21-F	TPMP22-S
334)	103)	TXVN2-2C	TCCP21-F	TPMP22-S	104)	TXJN3-2L	TCCP21-F	TPMP22-S	105)	TFLSW43G	TCCP21-F	TPMP22-S

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH THREE BASIC EVENTS

337)	106)	TXVN5040	TCCP21-F	TPMP22-S	107)	TCVN1-2Q	TPMP21-S	TMOP22-S	108)	TXVN2-2C	TPMP21-S	TMOP22-S
340)	109)	TXJN3-2L	TPMP21-S	TMOP22-S	110)	TFLSW43G	TPMP21-S	TMOP22-S	111)	TXVN5040	TPMP21-S	TMOP22-S
343)	112)	TCVN1-2Q	TMOP21-S	TMOP22-S	113)	TXVN2-2C	TMOP21-S	TMOP22-S	114)	TXJN3-2L	TMOP21-S	TMOP22-S
346)	115)	TFLSW43G	TMOP21-S	TMOP22-S	116)	TXVN5040	TMOP21-S	TMOP22-S	117)	TCVN1-2Q	TCCP21-F	TMOP22-S
349(	118)	TXVN2-2C	TCCP21-F	TMOP22-S	119)	TXJN3-2L	TCCP21-F	TMOP22-S	120)	TFLSW43G	TCCP21-F	TMOP22-S
352)	121)	TXVN5040	TCCP21-F	TMOP22-S	122)	TPMP21-S	TCCP22-F	TPMP23-S	123)	TMOP21-S	TCCP22-F	TPMP23-S
355)	124)	TCCP21-F	TCCP22-F	TPMP23-S	125)	TPMP21-S	TPMP22-S	TPMP23-S	126)	TMOP21-S	TPMP22-S	TPMP23-S
358)	127)	TCCP21-F	TPMP22-S	TPMP23-S	128)	TPMP21-S	TMOP22-S	TPMP23-S	129)	TMOP21-S	TMOP22-S	TPMP23-S
361)	130)	TCCP21-F	TMOP22-S	TPMP23-S	131)	TPMP21-S	TCCP22-F	TMOP23-S	132)	TMOP21-S	TCCP22-F	TMOP23-S
364)	133)	TCCP21-F	TCCP22-F	TMOP23-S	134)	TPMP21-S	TPMP22-S	TMOP23-S	135)	TMOP21-S	TPMP22-S	TMOP23-S
367)	136)	TCCP21-F	TPMP22-S	TMOP23-S	137)	TPMP21-S	TMOP22-S	TMOP23-S	138)	TMOP21-S	TMOP22-S	TMOP23-S
370)	139)	TCCP21-F	TMOP22-S	TMOP23-S	140)	TPMP21-S	TCCP22-F	TCCP23-F	141)	TMOP21-S	TCCP22-F	TCCP23-F
373)	142)	TCCP21-F	TCCP22-F	TCCP23-F	143)	TPMP21-S	TPMP22-S	TCCP23-F	144)	TMOP21-S	TPMP22-S	TCCP23-F
376)	145)	TCCP21-F	TPMP22-S	TCCP23-F	146)	TPMP21-S	TMOP22-S	TCCP23-F	147)	TMOP21-S	TMOP22-S	TCCP23-F
379)	148)	TCCP21-F	TMOP22-S	TCCP23-F	149)	TPMP21-S	TCVN1-1Q	TPMP23-S	150)	TMOP21-S	TCVN1-1Q	TPMP23-S
382)	151)	TCCP21-F	TCVN1-1Q	TPMP23-S	152)	TPMP21-S	TXVN2-1C	TPMP23-S	153)	TMOP21-S	TXVN2-1C	TPMP23-S
385)	154)	TCCP21-F	TXVN2-1C	TPMP23-S	155)	TPMP21-S	TXJN3-1L	TPMP23-S	156)	TMOP21-S	TXJN3-1L	TPMP23-S
388)	157)	TCCP21-F	TXJN3-1L	TPMP23-S	158)	TPMP21-S	TFLSW42G	TPMP23-S	159)	TMOP21-S	TFLSW42G	TPMP23-S
391)	160)	TCCP21-F	TFLSW42G	TPMP23-S	161)	TPMP21-S	TXVN5050	TPMP23-S	162)	TMOP21-S	TXVN5050	TPMP23-S
394)	163)	TCCP21-F	TXVN5050	TPMP23-S	164)	TPMP21-S	TCVN1-1Q	TMOP23-S	165)	TMOP21-S	TCVN1-1Q	TMOP23-S
397)	166)	TCCP21-F	TCVN1-1Q	TMOP23-S	167)	TPMP21-S	TXVN2-1C	TMOP23-S	168)	TMOP21-S	TXVN2-1C	TMOP23-S
400)	169)	TCCP21-F	TXVN2-1C	TMOP23-S	170)	TPMP21-S	TXJN3-1L	TMOP23-S	171)	TMOP21-S	TXJN3-1L	TMOP23-S
403)	172)	TCCP21-F	TXJN3-1L	TMOP23-S	173)	TPMP21-S	TFLSW42G	TMOP23-S	174)	TMOP21-S	TFLSW42G	TMOP23-S
406)	175)	TCCP21-F	TFLSW42G	TMOP23-S	176)	TPMP21-S	TXVN5050	TMOP23-S	177)	TMOP21-S	TXVN5050	TMOP23-S
409)	178)	TCCP21-F	TXVN5050	TMOP23-S	179)	TPMP21-S	TCVN1-1Q	TCCP23-F	180)	TMOP21-S	TCVN1-1Q	TCCP23-F
412)	181)	TCCP21-F	TCVN1-1Q	TCCP23-F	182)	TPMP21-S	TXVN2-1C	TCCP23-F	183)	TMOP21-S	TXVN2-1C	TCCP23-F
415)	184)	TCCP21-F	TXVN2-1C	TCCP23-F	185)	TPMP21-S	TXJN3-1L	TCCP23-F	186)	TMOP21-S	TXJN3-1L	TCCP23-F
418)	187)	TCCP21-F	TXJN3-1L	TCCP23-F	188)	TPMP21-S	TFLSW42G	TCCP23-F	189)	TMOP21-S	TFLSW42G	TCCP23-F
421)	190)	TCCP21-F	TFLSW42G	TCCP23-F	191)	TPMP21-S	TXVN5050	TCCP23-F	192)	TMOP21-S	TXVN5050	TCCP23-F
424)	193)	TCCP21-F	TXVN5050	TCCP23-F	194)	TCVN1-2Q	TCVN1--Q	TCVN1-1Q	195)	TXVN2-2C	TCVN1--Q	TCVN1-1Q
427)	196)	TXJN3-2L	TCVN1--Q	TCVN1-1Q	197)	TFLSW43G	TCVN1--Q	TCVN1-1Q	198)	TXVN5040	TCVN1--Q	TCVN1-1Q
430)	199)	TCVN1-2Q	TXVN2--C	TCVN1-1Q	200)	TXVN2-2C	TXVN2--C	TCVN1-1Q	201)	TXJN3-2L	TXVN2--C	TCVN1-1Q
433)	202)	TFLSW43G	TXVN2--C	TCVN1-1Q	203)	TXVN5040	TXVN2--C	TCVN1-1Q	204)	TCVN1-2Q	TXJN3--L	TCVN1-1Q

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH THREE BASIC EVENTS

436)	205)	TXVN2-2C	TXJN3--L	TCVN1-1Q	206)	TXNJ3-2L	TXJN3--L	TCVN1-1Q	207)	TFLSW43G	TXJN3--L	TCVN1-1Q
439)	208)	TXVN5040	TXJN3--L	TCVN1-1Q	209)	TCVN1-2Q	TFLSW41G	TCVN1-1Q	210)	TXVN2-2C	TFLSW41G	TCVN1-1Q
442)	211)	TXJN3-2L	TFLSW41G	TCVN1-1Q	212)	TFLSW43G	TFLSW41G	TCVN1-1Q	213)	TXVN5040	TFLSW41G	TCVN1-1Q
445)	214)	TCVN1-2Q	TXVN5060	TCVN1-1Q	215)	TXVN2-2C	TXVN5060	TCVN1-1Q	216)	TXJN3-2L	TXVN5060	TCVN1-1Q
448)	217)	TFLSW43G	TXVN5060	TCVN1-1Q	218)	TXVN5040	TXVN5060	TCVN1-1Q	219)	TCVN1-2Q	TCVN1--Q	TXVN2-1C
451)	220)	TXVN2-2C	TCVN1--Q	TXVN2-1C	221)	TXJN3-2L	TCVN1--Q	TXVN2-1C	222)	TFLSW43G	TCVN1--Q	TXVN2-1C
454)	223)	TXVN5040	TCVN1--Q	TXVN2-1C	224)	TCVN1-2Q	TXVN2--C	TXVN2-1C	225)	TXVN2-2C	TXVN2--C	TXVN2-1C
457)	226)	TXJN3-2L	TXVN2--C	TXVN2-1C	227)	TFLSW43G	TXVN2--C	TXVN2-1C	228)	TXVN5040	TXVN2--C	TXVN2-1C
460)	229)	TCVN1-2Q	TXJN3--L	TXVN2-1C	230)	TXVN2-2C	TXJN3--L	TXVN2-1C	231)	TXJN3-2L	TXJN3--L	TXVN2-1C
463)	232)	TFLSW43G	TXJN3--L	TXVN2-1C	233)	TXVN5040	TXJN3--L	TXVN2-1C	234)	TCVN1-2Q	TFLSW41G	TXVN2-1C
466)	235)	TXVN2-2C	TFLSW41G	TXVN2-1C	236)	TXJN3-2L	TFLSW41G	TXVN2-1C	237)	TFLSW43G	TFLSW41G	TXVN2-1C
469)	238)	TXVN5040	TFLSW41G	TXVN2-1C	239)	TCVN1-2Q	TXVN5060	TXVN2-1C	240)	TXVN2-2C	TXVN5060	TXVN2-1C
472)	241)	TXJN3-2L	TXVN5060	TXVN2-1C	242)	TFLSW43G	TXVN5060	TXVN2-1C	243)	TXVN5040	TXVN5060	TXVN2-1C
475)	244)	TCVN1-2Q	TCVN1--Q	TXJN3-1L	245)	TXVN2-2C	TCVN1--Q	TXJN3-1L	246)	TXJN3-2L	TCVN1--Q	TXJN3-1L
478)	247)	TFLSW43G	TCVN1--Q	TXJN3-1L	248)	TXVN5040	TCVN1--Q	TXJN3-1L	249)	TCVN1-2Q	TXVN2--C	TXJN3-1L
481)	250)	TXVN2-2C	TXVN2--C	TXJN3-1L	251)	TXJN3-2L	TXVN2--C	TXJN3-1L	252)	TFLSW43G	TXVN2--C	TXJN3-1L
484)	253)	TXVN5040	TXVN2--C	TXJN3-1L	254)	TCVN1-2Q	TXJN3--L	TXJN3-1L	255)	TXVN2-2C	TXJN3--L	TXJN3-1L
487)	256)	TXJN3-2L	TXJN3--L	TXJN3-1L	257)	TFLSW43G	TXJN3--L	TXJN3-1L	258)	TXVN5040	TXJN3--L	TXJN3-1L
490)	259)	TCVN1-2Q	TFSLW41G	TXJN3-1L	260)	TXVN2-2C	TFLSW41G	TXJN3-1L	261)	TXJN3-2L	TFLSW41G	TXJN3-1L
493)	262)	TFLSW43G	TFLSW41G	TXJN3-1L	263)	TXVN5040	TFLSW41G	TXJN3-1L	264)	TCVN1-2Q	TXVN5060	TXJN3-1L
496)	265)	TXVN2-2C	TXVN5060	TXJN3-1L	266)	TXJN3-2L	TXVN5060	TXJN3-1L	267)	TFLSW43G	TXVN5060	TXJN3-1L
499)	268)	TXVN5040	TXVN5060	TXJN3-1L	269)	TCVN1-2Q	TCVN1--Q	TFLSW42G	270)	TXVN2-2C	TCVN1--Q	TFLSW42G
502)	271)	TXJN3-2L	TCVN1--Q	TFLSW42G	272)	TFLSW43G	TCVN1--Q	TFSLW42G	273)	TXVN5040	TCVN1--Q	TFLSW42G
505)	274)	TCVN1-2Q	TXVN2--C	TFLSW42G	275)	TXVN2-2C	TXVN2--C	TFLSW42G	276)	TXJN3-2L	TXVN2--C	TFLSW42G
508)	277)	TFLSW43G	TXVN2--C	TFLSW42G	278)	TXVN5040	TXVN2--C	TFLSW42G	279)	TCVN1-2Q	TXJN3--L	TFLSW42G
511)	280)	TXVN2-2C	TXJN3--L	TFLSW42G	281)	TXJN3-2L	TXJN3--L	TFLSW42G	282)	TFLSW43G	TXJN3--L	TFLSW42G
514)	283)	TXVN5040	TXJN3--L	TFLSW42G	284)	TCVN1-2Q	TFLSW41G	TFLSW42G	285)	TXVN2-2C	TFLSW41G	TFLSW42G
517)	286)	TXJN3-2L	TFLSW41G	TFLSW42G	287)	TFLSW43G	TFLSW41G	TFLSW42G	288)	TXVN5040	TFLSW41G	TFLSW42G
520)	289)	TCVN1-2Q	TXVN5060	TFLSW42G	290)	TXVN2-2C	TXVN5060	TFLSW42G	291)	TXJN3-2L	TXVN5060	TFLSW42G
523)	292)	TFLSW43G	TXVN5060	TFLSW42G	293)	TXVN5040	TXVN5060	TFLSW42G	294)	TCVN1-2Q	TCVN1--Q	TXVN5050
526)	295)	TXVN2-2C	TCVN1--Q	TXVN5050	296)	TXJN3-2L	TCVN1--Q	TXVN5050	297)	TFLSW43G	TCVN1--Q	TXVN5050

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH THREE BASIC EVENTS

529)	298)	TXVN5040	TCVN1--Q	TXVN5050	299)	TCVN1-2Q	TXVN2--C	TXVN5050	300)	TXVN2-2C	TXVN2--C	TXVN5050
532)	301)	TXJN3-2L	TXVN2--C	TXVN5050	302)	TFLSW43G	TXVN2--C	TXVN5050	303)	TXVN5040	TXVN2--C	TXVN5050
535)	304)	TCVN1-2Q	TXJN3--L	TXVN5050	305)	TXVN2-2C	TXJN3--L	TXVN5050	306)	TXJN3-2L	TXJN3--L	TXVN5050
538)	307)	TFLSW43G	TXJN3--L	TXVN5050	308)	TXVN5040	TXJN3--L	TXVN5050	309)	TCVN1-2Q	TFLSW41G	TXVN5050
541)	310)	TXVN2-2C	TFLSW41G	TXVN5050	311)	TXJN3-2L	TFLSW41G	TXVN5050	312)	TFLSW43G	TFLSW41G	TXVN5050
544)	313)	TXVN5040	TFLSW41G	TXVN5050	314)	TCVN1-2Q	TXVN5060	TXVN5050	315)	TXVN2-2C	TXVN5060	TXVN5050
547)	316)	TXJN3-2L	TXVN5060	TXVN5050	317)	TFLSW43G	TXVN5060	TXVN5050	318)	TXVN5040	TXVN5060	TXVN5050
550)	319)	TCVN1-2Q	TCVN1--Q	TCCP22-F	320)	TXVN2-2C	TCVN1--Q	TCCP22-F	321)	TXJN3-2L	TCVN1--Q	TCCP22-F
553)	322)	TFLSW43G	TCVN1--Q	TCCP22-F	323)	TXVN5040	TCVN1--Q	TCCP22-F	324)	TCVN1-2Q	TXVN2--C	TCCP22-F
556)	325)	TXVN2-2C	TXVN2--C	TCCP22-F	326)	TXJN3-2L	TXVN2--C	TCCP22-F	327)	TFLSW43G	TXVN2--C	TCCP22-F
559)	328)	TXVN5040	TXVN2--C	TCCP22-F	329)	TCVN1-2Q	TXJN3--L	TCCP22-F	330)	TXVN2-2C	TXJN3--L	TCCP22-F
562)	331)	TXJN3-2L	TXJN3--L	TCCP22-F	332)	TFLSW43G	TXJN3--L	TCCP22-F	333)	TXVN5040	TXJN3--L	TCCP22-F
565)	334)	TCVN1-2Q	TFLSW41G	TCCP22-F	335)	TXVN2-2C	TFLSW41G	TCCP22-F	336)	TXJN3-2L	TFLSW41G	TCCP22-F
568)	337)	TFLSW43G	TFLSW41G	TCCP22-F	338)	TXVN5040	TFLSW41G	TCCP22-F	339)	TCVN1-2Q	TXVN5060	TCCP22-F
571)	340)	TXVN2-2C	TXVN5060	TCCP22-F	341)	TXJN3-2L	TXVN5060	TCCP22-F	342)	TFLSW43G	TXVN5060	TCCP22-F
574)	343)	TXVN5040	TXVN5060	TCCP22-F	344)	TCVN1-2Q	TCVN1--Q	TPMP22-S	345)	TXVN2-2C	TCVN1--Q	TPMP22-S
577)	346)	TXJN3-2L	TCVN1--Q	TPMP22-S	347)	TFLSW43G	TCVN1--Q	TPMP22-S	348)	TXVN5040	TCVN1--Q	TPMP22-S
580)	349)	TCVN1-2Q	TXVN2--C	TPMP22-S	350)	TXVN2-2C	TXVN2--C	TPMP22-S	351)	TXJN3-2L	TXVN2--C	TPMP22-S
583)	352)	TFLSW43G	TXVN2--C	TPMP22-S	353)	TXVN5040	TXVN2--C	TPMP22-S	354)	TCVN1-2Q	TXJN3--L	TPMP22-S
586)	355)	TXVN2-2C	TXJN3--L	TPMP22-S	356)	TXJN3-2L	TXJN3--L	TPMP22-S	357)	TFLSW43G	TXJN3--L	TPMP22-S
589)	358)	TXVN5040	TXJN3--L	TPMP22-S	359)	TCVN1-2Q	TFLSW41G	TPMP22-S	360)	TXVN2-2C	TFLSW41G	TPMP22-S
592)	361)	TXJN3-2L	TFLSW41G	TPMP22-S	362)	TFLSW43G	TFLSW41G	TPMP22-S	363)	TXVN5040	TFLSW41G	TPMP22-S
595)	364)	TCVN1-2Q	TXVN5060	TPMP22-S	365)	TXVN2-2C	TXVN5060	TPMP22-S	366)	TXJN3-2L	TXVN5060	TPMP22-S
598)	367)	TFLSW43G	TXVN5060	TPMP22-S	368)	TXVN5040	TXVN5060	TPMP22-S	369)	TCVN1-2Q	TCVN1--Q	TMOP22-S
601)	370)	TXVN2-2C	TCVN1--Q	TMOP22-S	371)	TXJN3-2L	TCVN1--Q	TMOP22-S	372)	TFLSW43G	TCVN1--Q	TMOP22-S
604)	373)	TXVN5040	TCVN1--Q	TMOP22-S	374)	TCVN1-2Q	TXVN2--C	TMOP22-S	375)	TXVN2-2C	TXVN2--C	TMOP22-S
607)	376)	TXJN3-2L	TXVN2--C	TMOP22-S	377)	TFLSW43G	TXVN2--C	TMOP22-S	378)	TXVN5040	TXVN2--C	TMOP22-S
610)	379)	TCVN1-2Q	TXJN3--L	TMOP22-S	380)	TXVN2-2C	TXJN3--L	TMOP22-S	381)	TXJN3-2L	TXJN3--L	TMOP22-S
613)	382)	TFLSW43G	TXJN3--L	TMOP22-S	383)	TXVN5040	TXJN3--L	TMOP22-S	384)	TCVN1-2Q	TFLSW41G	TMOP22-S
616)	385)	TXVN2-2C	TFLSW41G	TMOP22-S	386)	TXJN3-2L	TFLSW41G	TMOP22-S	387)	TFLSW43G	TFLSW41G	TMOP22-S
619)	388)	TXVN5040	TFLSW41G	TMOP22-S	389)	TCVN1-2Q	TXVN5060	TMOP22-S	390)	TXVN2-2C	TXVN5060	TMOP22-S
622)	391)	TXJN3-2L	TXVN5060	TMOP22-S	392)	TFLSW43G	TXVN5060	TMOP22-S	393)	TXVN5040	TXVN5060	TMOP22-S
625)	394)	TCVN1--Q	TCCP22-F	TPMP23-S	395)	TXVN2--C	TCCP22-F	TPMP23-S	396)	TXJN3--L	TCCP22-F	TPMP23-S

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH THREE BASIC EVENTS

628)	397)	TFLSW41G	TCCP22-F	TPMP23-S	398)	TXVN5060	TCCP22-F	TPMP23-S	399)	TCVN1--Q	TPMP22-S	TPMP23-S
631)	400)	TXVN2--C	TPMP22-S	TPMP23-S	401)	TXJN3--L	TPMP22-S	TPMP23-S	402)	TFLSW41G	TPMP22-S	TPMP23-S
634)	403)	TXVN5060	TPMP22-S	TPMP23-S	404)	TCVN1--Q	TMOP22-S	TPMP23-S	405)	TXVN2--C	TMOP22-S	TPMP23-S
637)	406)	TXJN3--L	TMOP22-S	TPMP23-S	407)	TFLSW41G	TMOP22-S	TPMP23-S	408)	TXVN5060	TMOP22-S	TPMP23-S
640)	409)	TCVN1--Q	TCCP22-F	TMOP23-S	410)	TXVN2--C	TCCP22-F	TMOP23-S	411)	TXJN3--L	TCCP22-F	TMOP23-S
643)	412)	TFLSW41G	TCCP22-F	TMOP23-S	413)	TXVN5060	TCCP22-F	TMOP23-S	414)	TCVN1--Q	TPMP22-S	TMOP23-S
646)	415)	TXVN2--C	TPMP22-S	TMOP23-S	416)	TXJN3--L	TPMP22-S	TMOP23-S	417)	TFLSW41G	TPMP22-S	TMOP23-S
649)	418)	TXVN5060	TPMP22-S	TMOP23-S	419)	TCVN1--Q	TMOP22-S	TMOP23-S	420)	TXVN2--C	TMOP22-S	TMOP23-S
652)	421)	TXJN3--L	TMOP22-S	TMOP23-S	422)	TFLSW41G	TMOP22-S	TMOP23-S	423)	TXVN5060	TMOP22-S	TMOP23-S
655)	424)	TCVN1--Q	TCCP22-F	TCCP23-F	425)	TXVN2--C	TCCP22-F	TCCP23-F	426)	TXJN3--C	TCCP22-F	TCCP23-F
658)	427)	TFLSW41G	TCCP22-F	TCCP23-F	428)	TXVN5060	TCCP22-F	TCCP23-F	429)	TCVN1--Q	TPMP22-S	TCCP23-F
661)	430)	TXVN2--C	TPMP22-S	TCCP23-F	431)	TXJN3--L	TPMP22-S	TCCP23-F	432)	TFLSW41G	TPMP22-S	TCCP23-F
664)	433)	TXVN5060	TPMP22-S	TCCP23-F	434)	TCVN1--Q	TMOP22-S	TCCP23-F	435)	TXVN2--C	TMOP22-S	TCCP23-F
667)	436)	TXJN3--L	TMOP22-S	TCCP23-F	437)	TFLSW41G	TMOP22-S	TCCP23-F	438)	TXVN5060	TMOP22-S	TCCP23-F
670)	439)	TCVN1--Q	TCVN1-1Q	TPMP23-S	440)	TXVN2--C	TCVN1-1Q	TPMP23-S	441)	TXJN3--L	TCVN1-1Q	TPMP23-S
673)	442)	TFLSW41G	TCVN1-1Q	TPMP23-S	443)	TXVN5060	TCVN1-1Q	TPMP23-S	444)	TCVN1--Q	TXVN2-1C	TPMP23-S
676)	445)	TXVN2--C	TXVN2-1C	TPMP23-S	446)	TXJN3--L	TXVN2-1C	TPMP23-S	447)	TFLSW41G	TXVN2-1C	TPMP23-S
679)	448)	TXVN5060	TXVN2-1C	TPMP23-S	449)	TCVN1--Q	TXJN3-1L	TPMP23-S	450)	TXVN2--C	TXJN3-1L	TPMP23-S
682)	451)	TXJN3--L	TXJN3-1L	TPMP23-S	452)	TFLSW41G	TXJN3-1L	TPMP23-S	453)	TXVN5060	TXJN3-1L	TPMP23-S
685)	454)	TCVN1--Q	TFLSW42G	TPMP23-S	455)	TXVN2--C	TFLSW42G	TPMP23-S	456)	TXJN3--L	TFLSW42G	TPMP23-S
688)	457)	TFLSW41G	TFLSW42G	TPMP23-S	458)	TXVN5060	TFLSW42G	TPMP23-S	459)	TCVN1--Q	TXVN5050	TPMP23-S
691)	460)	TXVN2--C	TXVN5050	TPMP23-S	461)	TXJN3--L	TXVN5050	TPMP23-S	462)	TFLSW41G	TXVN5050	TPMP23-S
694)	463)	TXVN5060	TXVN5050	TPMP23-S	464)	TCVN1--Q	TCVN1-1Q	TMOP23-S	465)	TXVN2--C	TCVN1-1Q	TMOP23-S
697)	466)	TXJN3--L	TCVN1-1Q	TMOP23-S	467)	TFLSW41G	TCVN1-1Q	TMOP23-S	468)	TXVN5060	TCVN1-1Q	TMOP23-S
700)	469)	TCVN1--Q	TXVN2-1C	TMOP23-S	470)	TXVN2--C	TXVN2-1C	TMOP23-S	471)	TXJN3--L	TXVN2-1C	TMOP23-S
703)	472)	TFLSW41G	TXVN2-1C	TMOP23-S	473)	TXVN5060	TXVN2-1C	TMOP23-S	474)	TCVN1--Q	TXJN3-1L	TMOP23-S
706)	475)	TXVN2--C	TXJN3-1L	TMOP23-S	476)	TXJN3--L	TXJN3-1L	TMOP23-S	477)	TFLSW41G	TXJN3-1L	TMOP23-S
709)	478)	TXVN5060	TXJN3-1L	TMOP23-S	479)	TCVN1--Q	TFLSW42G	TMOP23-S	480)	TXVN2--C	TFLSW42G	TMOP23-S
712)	481)	TXJN3--L	TFLSW42G	TMOP23-S	482)	TFLSW41G	TFLSW42G	TMOP23-S	483)	TXVN5060	TFLSW42G	TMOP23-S
715)	484)	TCVN1--Q	TXVN5050	TMOP23-S	485)	TXVN2--C	TXVN5050	TMOP23-S	486)	TXJN3--L	TXVN5050	TMOP23-S
718)	487)	TFLSW41G	TXVN5050	TMOP23-S	488)	TXVN5060	TXVN5050	TMOP23-S	489)	TCVN1--Q	TCVN1-1Q	TCCP23-F
721)	490)	TXVN2--C	TCVN1-1Q	TCCP23-F	491)	TXJN3--L	TCVN1-1Q	TCCP23-F	492)	TFLSW41G	TCVN1-1Q	TCCP23-F

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH THREE BASIC EVENTS

724)	493)	TXVN5060	TCVN1-1Q	TCCP23-F	494)	TCVN1--Q	TXVN2-1C	TCCP23-F	495)	TXVN2--C	TXVN2-1C	TCCP23-F
727)	496)	TXJN3--L	TXVN2-1C	TCCP23-F	497)	TFLSW41G	TXVN2-1C	TCCP23-F	498)	TXVN5060	TXVN2-1C	TCCP23-F
730)	499)	TCVN1--Q	TXJN3-1L	TCCP23-F	500)	TXVN2--C	TXJN3-1L	TCCP23-F	501)	TXJN3--L	TXJN3-1L	TCCP23-F
733)	502)	TFLSW41G	TXJN3-1L	TCCP23-F	503)	TXVN5060	TXJN3-1L	TCCP23-F	504)	TCVN1--Q	TFLSW42G	TCCP23-F
736)	505)	TXVN2--C	TFLSW42G	TCCP23-F	506)	TXJN3--L	TFLSW42G	TCCP23-F	507)	TFLSW41G	TFLSW42G	TCCP23-F
739)	508)	TXVN5060	TFLSW42G	TCCP23-F	509)	TCVN1--Q	TXVN5050	TCCP23-F	510)	TXVN2--C	TXVN5050	TCCP23-F
742)	511)	TXJN3--L	TXVN5050	TCCP23-F	512)	TFLSW41G	TXVN5050	TCCP23-F	513)	TXVN5060	TXVN5050	TCCP23-F
745)	514)	TCVN1-5Q	JBS-23AD	JBS-22AD	515)	TXVN2-5C	JBS-23AD	JBS-22AD	516)	TXJN3-5L	JBS-23AD	JBS-22AD
748)	517)	TFLSW46G	JBS-23AD	JBS-22AD	518)	TXVN5010	JBS-23AD	JBS-22AD	519)	JBS-23AD	TCVN1-3Q	JBS-22AD
751)	520)	JBS-23AD	TXVN2-3C	JBS-22AD	521)	JBS-23AD	TXJN3-3L	JBS-22AD	522)	JBS-23AD	TFLSW44G	JBS-22AD
754)	523)	JBS-23AD	TXVN5030	JBS-22AD	524)	JBS-23AD	JBS-22AD	TPMP26-S	525)	JBS-23AD	JBS-22AD	TMOP26-S
757)	526)	JBS-23AD	JBS-22AD	TCCP26-F	527)	JBS-23AD	TPMP24-S	JBS-22AD	528)	JBS-23AD	TMOP24-S	JBS-22AD
760)	529)	JBS-23AD	TCCP24-F	JBS-22AD	530)	TPMP21-S	TCCP22-F	JBS-26AD	531)	TMOP21-S	TCCP22-F	JBS-26AD
763)	532)	TCCP21-F	TCCP22-F	JBS-26AD	533)	TPMP21-S	TPMP22-S	JBS-26AD	534)	TMOP21-S	TPMP22-S	JBS-26AD
766)	535)	TCCP21-F	TPMP22-S	JBS-26AD	536)	TPMP21-S	TMOP22-S	JBS-26AD	537)	TMOP21-S	TMOP22-S	JBS-26AD
769)	538)	TCCP21-F	TMOP22-S	JBS-26AD	539)	TPMP21-S	TCVN1-1Q	JBS-26AD	540)	TMOP21-S	TCVN1-1Q	JBS-26AD
772)	541)	TCCP21-F	TCVN1-1Q	JBS-26AD	542)	TPMP21-S	TXVN2-1C	JBS-26AD	543)	TMOP21-S	TXVN2-1C	JBS-26AD
775)	544)	TCCP21-F	TXVN2-1C	JBS-26AD	545)	TPMP21-S	TXJN3-1L	JBS-26AD	546)	TMOP21-S	TXJN3-1L	JBS-26AD
778)	547)	TCCP21-F	TXJN3-1L	JBS-26AD	548)	TPMP21-S	TFLSW42G	JBS-26AD	549)	TMOP21-S	TFLSW42G	JBS-26AD
781)	550)	TCCP21-F	TFLSW42G	JBS-26AD	551)	TPMP21-S	TXVN5050	JBS-26AD	552)	TMOP21-S	TXVN5050	JBS-26AD
784)	553)	TCCP21-F	TXVN5050	JBS-26AD	554)	TCVN1--Q	TCCP22-F	JBS-26AD	555)	TXVN2--C	TCCP22-F	JBS-26AD
787)	556)	TXJN3--L	TCCP22-F	JBS-26AD	557)	TFLSW41G	TCCP22-F	JBS-26AD	558)	TXVN5060	TCCP22-F	JBS-26AD
790)	559)	TCVN1--Q	TPMP22-S	JBS-26AD	560)	TXVN2--D	TPMP22-S	JBS-26AD	561)	TXJN3--L	TPMP22-S	JBS-26AD
793)	562)	TFLSW41G	TPMP22-S	JBS-26AD	563)	TXVN5060	TPMP22-S	JBS-26AD	564)	TCVN1--Q	TMOP22-S	JBS-26AD
796)	565)	TXVN2--C	TMOP22-S	JBS-26AD	566)	TXJN3--L	TMOP22-S	JBS-26AD	567)	TFLSW41G	TMOP22-S	JBS-26AD
799)	568)	TXVN5060	TMOP22-S	JBS-26AD	569)	TCVN1--Q	TCVN1-1Q	JBS-26AD	570)	TXVN2--F	TCVN1-1Q	JBS-26AD
802)	571)	TXJN3--L	TCVN1-1Q	JBS-26AD	572)	TFLSW41G	TCVN1-1Q	JBS-26AD	573)	TXVN5060	TCVN1-1Q	JBS-26AD
805)	574)	TCVN1--Q	TXVN2-1C	JBS-26AD	575)	TXVN2--C	TXVN2-1C	JBS-26AD	576)	TXJN3--L	TXVN2-1C	JBS-26AD
808)	577)	TFLSW41G	TXVN2-1C	JBS-26AD	578)	TXVN5060	TXVN2-1C	JBS-26AD	579)	TCVN1--Q	TXJN3-1L	JBS-26AD
811)	580)	TXVN2--C	TXJN3-1L	JBS-26AD	581)	TXJN3--L	TXJN3-1L	JBS-26AD	582)	TFLSW41G	TXJN3-1L	JBS-26AD
814)	583)	TXVN5060	TXJN3-1L	JBS-26AD	584)	TCVN1--Q	TFLSW42G	JBS-26AD	585)	TXVN2--C	TFLSW42G	JBS-26AD
817)	586)	TXJN3--L	TFLSW42G	JBS-26AD	587)	TFLSW41G	TFLSW42G	JBS-26AD	588)	TXVN5060	TFLSW42G	JBS-26AD

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH THREE BASIC EVENTS

820)	589)	TCVN1--Q	TXVN5050	JBS-26AD	590)	TXVN2--C	TXVN5050	JBS-26AD	591)	TXJN3--L	TXVN5050	JBS-26AD
823)	592)	TFLSW41G	TXVN5050	JBS-26AD	593)	TXVN5060	TXVN5050	JBS-26AD	594)	JBS-23AD	JBS-22AD	JBS-26AD
826)	595)	TCVN1-2Q	JBS-25AD	TCVN1-1Q	596)	TXVN2-2C	JBS-25AD	TCVN1-1Q	597)	TXJN3-2L	JBS-25AD	TCVN1-1Q
829)	598)	TFLSW43G	JBS-25AD	TCVN1-1Q	599)	TXVN5040	JBS-25AD	TCVN1-1Q	600)	TCVN1-2Q	JBS-25AD	TXVN2-1C
832)	601)	TXVN2-2C	JBS-25AD	TXVN2-1C	602)	TXJN3-2L	JBS-25AD	TXVN2-1C	603)	TFLSW43G	JBS-25AD	TXVN2-1C
835)	604)	TXVN5040	JBS-25QD	TXVN2-1C	605)	TCVN1-2Q	JBS-25AD	TXJN3-1L	606)	TXVN2-2C	JBS-25AD	TXJN3-1L
838)	607)	TXJN3-2L	JBS-25AD	TXJN3-1L	608)	TFLSW43G	JBS-25AD	TXJN3-1L	609)	TXVN5040	JBS-25AD	TXJN3-1L
841)	610)	TCVN1-2Q	JBS-25AD	TFLSW42G	611)	TXVN2-2C	JBS-25AD	TFLSW42G	612)	TXJN3-2L	JBS-25AD	TFLSW42G
844)	613)	TFLSW43G	JBS-25AD	TFLSW42G	614)	TXVN5040	JBS-25AD	TFLSW42G	615)	TCVN1-2Q	JBS-25AD	TXVN5050
847)	616)	TXVN2-2C	JBS-25AD	TXVN5050	617)	TXJN3-2L	JBS-25AD	TXVN5050	618)	TFLSW43G	JBS-25AD	TXVN5050
850)	619)	TXVN5040	JBS-25AD	TXVN5050	620)	TCVN1-2Q	JBS-25AD	TCCP22-F	621)	TXVN2-2C	JBS-25AD	TCCP22-F
853)	622)	TXJN3-2L	JBS-25AD	TCCP22-F	623)	TFLSW43G	JBS-25AD	TCCP22-F	624)	TXVN5040	JBS-25AD	TCCP22-F
856)	625)	TCVN1-2Q	JBS-25AD	TPMP22-S	626)	TXVN2-2C	JBS-25AD	TPMP22-S	627)	TXJN3-2L	JBS-25AD	TPMP22-S
859)	628)	TFLSW43G	JBS-25AD	TPMP22-S	629)	TXVN5040	JBS-25AD	TPMP22-S	630)	TCVN1-2Q	JBS-25AD	TMOP22-S
862)	631)	TXVN2-2C	JBS-25AD	TMOP22-S	632)	TXJN3-2L	JBS-25AD	TMOP22-S	633)	TFLSW43G	JBS-25AD	TMOP22-S
865)	634)	TXVN5040	JBS-25AD	TMOP22-S	635)	JBS-25AD	TCCP22-F	TPMP23-S	636)	JBS-25AD	TPMP22-S	TPMP23-S
868)	637)	JBS-25AD	TMOP22-S	TPMP23-S	638)	JBS-25AD	TCCP22-F	TMOP23-S	639)	JBS-25AD	TPMP22-S	TMOP23-S
871)	640)	JBS-25AD	TMOP22-S	TMOP23-S	641)	JBS-25AD	TCCP22-F	TCCP23-F	642)	JBS-25AD	TPMP22-S	TCCP23-F
874)	643)	JBS-25AD	TMOP22-S	TCCP23-F	644)	JBS-25AD	TCVN1-1Q	TPMP23-S	645)	JBS-25AD	TXVN2-1C	TPMP23-S
877)	646)	JBS-25AD	TXJN3-1L	TPMP23-S	647)	JBS-25AD	TFLSW42G	TPMP23-S	648)	JBS-25AD	TXVN5050	TPMP23-S
880)	649)	JBS-25AD	TCVN1-1Q	TMOP23-S	650)	JBS-25AD	TXVN2-1C	TMOP23-S	651)	JBS-25AD	TXJN3-1L	TMOP23-S
883)	652)	JBS-25AD	TFLSW42G	TMOP23-S	653)	JBS-25AD	TXVN5050	TMOP23-S	654)	JBS-25AD	TCVN1-1Q	TCCP23-F
886)	655)	JBS-25AD	TXVN2-1C	TCCP23-F	656)	JBS-25AD	TXJN3-1L	TCCP23-F	657)	JBS-25AD	TFLSW42G	TCCP23-F
888)	658)	JBS-25AD	TXVN5050	TCCP23-F	659)	JBS-23AD	JBS-25AD	JBS-22AD				

CUTSETS WITH FOUR BASIC EVENTS

890)	1)	TCVN1-2Q	JBS-23AD	TCVN1--Q	JBS-22AD	2)	TXVN2-2C	JBS-23AD	TCVN1--Q	JBS-22AD
892)	3)	TXJN3-2L	JBS-23AD	TCVN1--Q	JBS-22AD	4)	TFLSW43G	JBS-23AD	TCVN1--Q	JBS-22AD
894)	5)	TXVN5040	JBS-23AD	TCVN1--Q	JBS-22AD	6)	TCVN1-2Q	JBS-23AD	TXVN2--C	JBS-22AD
896)	7)	TXVN2-2C	JBS-23AD	TXVN2--C	JBS-22AD	8)	TXJN3-2L	JBS-23AD	TXVN2--C	JBS-22AD
898)	9)	TFLSW43G	JBS-23AD	TXVN2--C	JBS-22AD	10)	TXVN5040	JBS-23AD	TXVN2--C	JBS-22AD

TABLE 1.5.2.3.8-5 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM CUTSETS

CUTSETS WITH FOUR BASIC EVENTS

900)	11)	TCVN1-2Q	JBS-23AD	TXJN3--L	JBS-22AD	12)	TXVN2-2C	JBS-23AD	TXJN3--L	JBS-22AD
902)	13)	TXJN3-2L	JBS-23AD	TXJN3--L	JBS-22AD	14)	TFLSW43G	JBS-23AD	TXJN3--L	JBS-22AD
904)	15)	TXVN5040	JBS-23AD	TXJN3--L	JBS-22AD	16)	TCVN1-2Q	JBS-23AD	TFLSW41G	JBS-22AD
906)	17)	TXVN2-2C	JBS-23AD	TFLSW41G	JBS-22AD	18)	TXJN3-2L	JBS-23AD	TFLSW41G	JBS-22AD
908)	19)	TFLSW43G	JBS-23AD	TFLSW41G	JBS-22AD	20)	TXVN5040	JBS-23AD	TFLSW41G	JBS-22AD
910)	21)	TCVN1-2Q	JBS-23AD	TXVN5060	JBS-22AD	22)	TXVN2-2C	JBS-23AD	TXVN5060	JBS-22AD
912)	23)	TXJN3-2L	JBS-23AD	TXVN5060	JBS-22AD	24)	TFLSW43G	JBS-23AD	TXVN5060	JBS-22AD
914)	25)	TXVN5040	JBS-23AD	TXVN5060	JBS-22AD	26)	TCVN1-2Q	JBS-23AD	TPMP21-S	JBS-22AD
916)	27)	TXVN2-2C	JBS-23AD	TPMP21-S	JBS-22AD	28)	TXJN3-2L	JBS-23AD	TPMP21-S	JBS-22AD
918)	29)	TFLSW43G	JBS-23AD	TPMP21-S	JBS-22AD	30)	TXVN5040	JBS-23AD	TPMP21-S	JBS-22AD
920)	31)	TCVN1-2Q	JBS-23AD	TMOP21-S	JBS-22AD	32)	TXVN2-2C	JBS-23AD	TMOP21-S	JBS-22AD
922)	33)	TXJN3-2L	JBS-23AD	TMOP21-S	JBS-22AD	34)	TFLSW43G	JBS-23AD	TMOP21-S	JBS-22AD
924)	35)	TXVN5040	JBS-23AD	TMOP21-S	JBS-22AD	36)	TCVN1-2Q	JBS-23AD	TCCP21-F	JBS-22AD
926)	37)	TXVN2-2C	JBS-23AD	TCCP21-F	JBS-22AD	38)	TXJN3-2L	JBS-23AD	TCCP21-F	JBS-22AD
928)	39)	TFLSW43G	JBS-23AD	TCCP21-F	JBS-22AD	40)	TXVN5040	JBS-23AD	TCCP21-F	JBS-22AD
930)	41)	JBS-23AD	TPMP21-S	JBS-22AD	TPMP23-S	42)	JBS-23AD	TMOP21-S	JBS-22AD	TPMP23-S
932)	43)	JBS-23AD	TCCP21-F	JBS-22AD	TPMP23-S	44)	JBS-23AD	TPMP21-S	JBS-22AD	TMOP23-S
934)	45)	JBS-23AD	TMOP21-S	JBS-22AD	TMOP23-S	46)	JBS-23AD	TCCP21-F	JBS-22AD	TMOP23-S
936)	47)	JBS-23AD	TPMP21-S	JBS-22AD	TCCP23-F	48)	JBS-23AD	TMOP21-S	JBS-22AD	TCCP23-F
938)	49)	JBS-23AD	TCCP21-F	JBS-22AD	TCCP23-F	50)	JBS-23AD	TCVN1--Q	JBS-22AD	TPMP23-S
940)	51)	JBS-23AD	TXVN2--C	JBS-22AD	TPMP23-S	52)	JBS-23AD	TXJN3--L	JBS-22AD	TPMP23-S
942)	53)	JBS-23AD	TFLSW41G	JBS-22AD	TPMP23-S	54)	JBS-23AD	TXVN5060	JBS-22AD	TPMP23-S
944)	55)	JBS-23AD	TCVN1--Q	JBS-22AD	TMOP23-S	56)	JBS-23AD	TXVN2--C	JBS-22AD	TMOP23-S
946)	57)	JBS-23AD	TXJN3--L	JBS-22AD	TMOP23-S	58)	JBS-23AD	TFLSW41G	JBS-22AD	TMOP23-S
948)	59)	JBS-23AD	TXVN5060	JBS-22AD	TMOP23-S	60)	JBS-23AD	TCVN1--Q	JBS-22AD	TCCP23-F
950)	61)	JBS-23AD	TXVN2--C	JBS-22AD	TCCP23-F	62)	JBS-23AD	TXJN3--L	JBS-22AD	TCCP23-F
952)	63)	JBS-23AD	TFLSW41G	JBS-22AD	TCCP23-F	64)	JBS-23AD	TXVN5060	JBS-22AD	TCCP23-F

TABLE 1.5.2.3.8-6

INDIAN POINT 2 SERVICE WATER SYSTEM - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential for Other Systems Impact	Comments
A. NUCLEAR HEADER				
1. 408				
a. Pumps 24, 25, 26 Discharge Header	24	Yes	Loss of cooling to containment building fan cooling units (CBFCUs) and emergency diesel generators (EDGs).	Operator can isolate and shift services to an intact header. (Time required approximately 1 hour.)
b. Supply to CBFCUs (after SWN-38)	18	Yes	Same as 1a.	Operator can isolate SWN-38 and recover EDGs. (T ≈ 15 min.) Isolation at SWN-40 or SWN-40-1 and opening of SWN-39 recovers two of five CBFCUs. (T ≈ 30 min.)
c. Supply to CBFCUs (after SWN-38)	14	Yes	Same as 1a.	Same as 1b.
d. Supply to CBFCUs (after SWN-40, 40-1)	18	Yes	Same as 1a.	Operator can isolate SWN-40 or 40-1 and recover three of five CBFCUs and EDGs. (T ≈ 15 min.)

TABLE 1.5.2.3.8-6 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential for Other Systems Impact	Comments
e. Supply to Various Conventional Plant Services (before FCV-1111)	16	Yes	Same as 1a.	Same as 1a.
f. Supply to intake structure services (upstream of SWN-5)	8	Yes	Same as 1a.	Same as 1a.
2. 407				
a. Supply to Component Cooling System (CCS) Heat Exchanger (before SWN-31)	20	Yes	Same as 1a.	Same as 1a.
3. 414				
a. Supply to EDGs (after SWN-29)	10	Yes	Same as 1a.	Operator can isolate at SWN-29 and recover all five CBFCUs. (T ≈ 15 min.) Isolation of individual EDG header supply valves and shift of headers by opening SWN-30 restores the EDGs. (T ≈ 30 minutes.)

TABLE 1.5.2.3.8-6 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential for Other Systems Impact	Comments
b. Supply to EDGs (before SWN-29)	10	Yes	Same as 1a.	Same as 1a.
4. 410				
a. Supply to Turbine Oil Coolers, etc. (before SWN-6)	10	Yes	Same as 1a.	Same as 1a.
b. Supply to Turbine Oil Coolers, etc. (after SWN-6)	10	Yes	Same as 1a.	Operator can isolate at SWN-6 and recover header. (T ≈ 15 min.)
5. 413				
a. Supply to EDG (after SWN-30)	10	Yes	Same as 1a.	Operator can isolate individual EDG header supply valves downstream of SWN-30 and recover all five CBFCUs and all three EDGs. (T ≈ 15 min.)
6. 409				
a. Supply to CBFCU (after SWN-39)	18	Yes	Same as 1a.	Same as 1d.

TABLE 1.5.2.3.8-6 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential for Other Systems Impact	Comments
7. 11				
a. 11a Supply to CBFCU 21 (before SWN-41-1-B)	10	Yes	Same as 1a.	Same as 1b.
b. 11b Supply to CBFCU 23 (before SWN-41-3-B)	10	Yes	Same as 1a.	Same as 1d.
c. 11c Supply to CBFCU 24 (before SWN-41-4-B)	10	Yes	Same as 1a.	Same as 1d.
d. 11d Supply to CBFCU 22 (before SWN-41-2-B)	10	Yes	Same as 1a.	Same as 1c.
e. 11e Supply to CBFCU 25 (before SWN-41-5-B)	10	Yes	Same as 1a.	Same as 1c.
8. a. 406 (in vicinity of TCV-1103, 1104, 1105)	18	No	Flooding in lower levels of PAB	Operator action to open doors on lower levels minimizes effects of flooding.
B. CONVENTIONAL HEADER				
9. 409				
a. Pumps 21, 22, 23 Discharge Header	24	Yes	Loss of cooling to CCS heat exchangers.	Same as 1a.

TABLE 1.5.2.3.8-6 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential for Other Systems Impact	Comments
b. Supply to Various Conventional Plant Services (before FCV-1112)	16	Yes	Same as 9a.	Same as 1a.
c. Supply to Various Conventional Plant Services (after FCV-1112)	16	Yes	Same as 9a.	Operator can isolate FCV-1112 and recover header. (T≈15 min.)
d. Supply to Intake Structure Services (upstream of SWN-4)	8	Yes	Same as 9a.	Same as 1a.
e. Supply to Intake Structure Services (after SWN-4)	8	Yes	Same as Item 9a.	Operator can isolate at SWN-4 and recover header. (T≈15 min.)
10. 407				
a. Supply to CCS Heat Exchanger (after SWN-31)	18	Yes	Loss of cooling to CCS heat exchangers.	Operator can isolate at SWN-31-1 or 33 and restore cooling to one CCS heat exchanger. (T≈15 min.)
11. 411				
a. Supply to CCS Heat Exchanger (before SWN-32)	20	Yes	Same as 9a.	Same as 1a.

TABLE 1.5.2.3.8-6 (continued)

INDIAN POINT 2 SERVICE WATER SYSTEM - SYSTEM EFFECTS OF PIPE FAILURE

Pipe Section	Diameter (inches)	System Failure	Potential for Other Systems Impact	Comments
b. Supply to CCS Heat Exchanger (after SWN-32) (includes 18 inches - 407)	18	Yes	Same as 9a.	Operator can isolate at SWN-32, 34, and 33 (or 31-1) and open SWN-31 and restore cooling to one CCS heat exchanger. (T ≈ 30 min.)
12. 413				
a. Supply to EDG (Before SWN-30)	10	Yes	Same as 9a.	Same as 1a.
13. 410				
a. Supply to Turbine Oil Coolers, etc. (before SWN-7)	10	Yes	Same as 9a.	Same as 1a.
14. 405				
a. Outlet CCS Heat Exchanger 21 (after SWN-35) (inside PAB)	18	Yes	Same as 9a.	Loss of CCS heat exchangers (isolated to minimize flooding effects in PAB).
b. Outlet CCS Heat Exchanger 22 (after SWN-35-1) (Inside PAB)	18	Yes	Same as 9a.	Same as 14a.

TABLE 1.5.2.3.8-7A

INDIAN POINT 2 BOUNDARY CONDITION, ELECTRIC POWER AVAILABLE AT ALL SWITCHGEAR BUSES, NUCLEAR HEADER

Component	Failure Data (Hourly) Mean	Failure Data (Hourly) Variance	Failure Data (Demand) Mean	Failure Data (Demand) Variance	System Effect	Failure Data (t = 24 hours) Mean	Failure Data (t = 24 hours) Variance
A. Single Events							
1. Water Supply							
a. Screen Plugging	2.66×10^{-5}	4.32×10^{-9}	-	-			
b. Bypass Gates Failure	-	-	7.49×10^{-4}	4.01×10^{-7}			
TOTAL					System Failure	6.03×10^{-10}	9.54×10^{-18}
2. Piping Failures	1.46×10^{-8}	1.24×10^{-14}	-	-	System Failure	3.51×10^{-7}	7.14×10^{-12}
B. Double Events							
1. Pump Trains							
a. Pump Fails to Start	-	-	6.41×10^{-3}	7.78×10^{-6}			
b. Pump Fails to Run	1.52×10^{-5}	2.09×10^{-10}	-	-			
c. Expansion Joint Ruptures	8.60×10^{-9}	6.00×10^{-15}	-	-			
d. Discharge Strainer Plugs	2.66×10^{-5}	4.32×10^{-9}	-	-			
e. Test Valve Open	1.99×10^{-8}	1.83×10^{-13}	-	-			
f. Check Valve Fails	-	-	7.02×10^{-5}	1.09×10^{-8}			
g. Discharge Valve Fails	7.40×10^{-8}	5.89×10^{-15}	-	-			
Single Train Total	4.19×10^{-5}	3.44×10^{-9}	6.48×10^{-3}	7.31×10^{-6}			
Two of Three Pump Trains	-	-	-	-	System Failure	1.89×10^{-4}	1.46×10^{-8}
2. EDG Flow Control Valve							
a. Valve Fails	-	-	7.49×10^{-4}	4.01×10^{-7}			
TOTAL	-	-	-	-	System Failure	9.44×10^{-7}	6.36×10^{-12}
3. Pump Failure to Start and check valve fails open	-	-	-	-	System Failure	9.64×10^{-6}	8.02×10^{-11}
C. Test (with pump trains)	-	-	-	-			
D. Human Error							
1. Mispositioned Switch	-	-	-	-	System Failure	1.11×10^{-5}	3.94×10^{-9}
2. Test Lineup Error	-	-	-	-	System Failure	3.30×10^{-5}	4.16×10^{-9}
E. Common Cause	*						
F. Other	*						
G. Header Total	-	-	-	-	System Failure	2.44×10^{-4}	2.16×10^{-8}

*Negligible failure frequency.

TABLE 1.5.2.3.8-7B

INDIAN POINT 2 BOUNDARY CONDITION, ELECTRIC POWER AVAILABLE AT ALL SWITCHGEAR BUSES, CONVENTIONAL HEADER

Component	Failure Data (Hourly) Mean	Failure Data (Hourly) Variance	Failure Data (Demand) Mean	Failure Data (Demand) Variance	System Effect	Failure Data (t = 24 hours) Mean	Failure Data (t = 24 hours) Variance
A. Single Events							
1. Water Supply							
a. Screen Plugging	2.66×10^{-5}	4.32×10^{-9}	-	-			
b. Bypass Gates Failure	-	-	7.49×10^{-4}	4.01×10^{-7}			
TOTAL	-	-	-	-	System Failure	6.03×10^{-10}	9.54×10^{-18}
2. Piping Failures	1.12×10^{-8}	7.25×10^{-15}	-	-	System Failure	2.68×10^{-7}	4.18×10^{-12}
B. Triple Events							
1. Pump Trains							
a. Pump Fails to Start	-	-	6.41×10^{-3}	7.78×10^{-6}			
b. Pump Fails to Run	1.52×10^{-5}	2.09×10^{-10}	-	-			
c. Expansion Joint Ruptures	8.60×10^{-9}	6.00×10^{-15}	-	-			
d. Discharge Strainer Plugs	2.66×10^{-5}	4.32×10^{-9}	-	-			
e. Test Valve Open	1.99×10^{-8}	1.83×10^{-13}	-	-			
f. Check Valve Fails	-	-	7.02×10^{-5}	1.09×10^{-8}			
g. Discharge Valve Fails	7.40×10^{-8}	5.89×10^{-15}	-	-			
Single Train Total	4.19×10^{-5}	3.44×10^{-9}	6.52×10^{-3}	7.32×10^{-6}			
(1/3) Pump Trains Total	-	-	-	-	System Failure	4.97×10^{-6}	2.50×10^{-11}
C. Test and Maintenance (with pump trains)	-	-	-	-			
D. Human Error							
1. Test Lineup Error	-	-	-	-	System Failure	1.43×10^{-7}	1.31×10^{-13}
E. Common Cause	*						
F. Other	*						
G. Header Total					System Failure	5.38×10^{-6}	2.66×10^{-11}

*Negligible failure frequency.

TABLE 1.5.2.3.8-7C

INDIAN POINT 2 BOUNDARY CONDITION, LOSS OF ELECTRIC POWER AT ONE SWITCHGEAR BUS, NUCLEAR HEADER

Component	Failure Data (Hourly) Mean	Failure Data (Hourly) Variance	Failure Data (Demand) Mean	Failure Data (Demand) Variance	System Effect	Failure Data (t = 24 hours) Mean	Failure Data (t = 24 hours) Variance
A. Single Events							
1. Water Supply							
a. Screen Plugging	2.66×10^{-5}	4.32×10^{-9}	-	-			
b. Bypass Gates Failure	-	-	7.49×10^{-4}	4.01×10^{-7}			
TOTAL					System Failure	6.03×10^{-10}	9.54×10^{-18}
2. Piping Failures	1.46×10^{-8}	1.24×10^{-14}	-	-	System Failure	3.51×10^{-7}	7.14×10^{-12}
B. Double Events							
1. Pump Trains							
a. Pump Fails to Start	-	-	6.41×10^{-3}	7.78×10^{-6}			
b. Pump Fails to Run	1.52×10^{-5}	2.09×10^{-10}	-	-			
c. Expansion Joint Ruptures	8.60×10^{-9}	6.00×10^{-15}	-	-			
d. Discharge Strainer Plugs	2.66×10^{-5}	4.32×10^{-9}	-	-			
e. Test Valve Open	1.99×10^{-8}	1.83×10^{-13}	-	-			
f. Check Valve Fails	-	-	7.02×10^{-5}	1.09×10^{-8}			
g. Discharge Valve Fails	7.40×10^{-8}	5.89×10^{-15}	-	-			
Single Train Total	4.19×10^{-5}	3.44×10^{-9}	6.48×10^{-3}	7.31×10^{-6}			
2 of 3 Pump Trains	-	-	-	-	System Failure	1.80×10^{-2}	3.30×10^{-5}
2. EDG Flow Control Valve							
a. Valve Fails	-	-	7.49×10^{-4}	4.01×10^{-7}			
TOTAL	-	-	-	-	System Failure	9.44×10^{-7}	6.36×10^{-12}
C. Test and Maintenance (with pump trains)	-	-	-	-			
D. Human Error							
1. Mispositioned Switch	-	-	-	-	System Failure	1.11×10^{-5}	3.94×10^{-9}
2. Test Lineup Error (with pump trains)	-	-	-	-			
E. Common Cause	*						
F. Other	*						
G. Header Total	-	-	-	-	System Failure	1.80×10^{-2}	3.29×10^{-5}

*Neglibible failure frequency.

TABLE 1.5.2.3.8-7D

INDIAN POINT 2 BOUNDARY CONDITION, LOSS OF ELECTRIC POWER AT ONE SWITCHGEAR BUS, CONVENTIONAL HEADER

Component	Failure Data (Hourly) Mean	Failure Data (Hourly) Variance	Failure Data (Demand) Mean	Failure Data (Demand) Variance	System Effect	Failure Data (t = 24 hours) Mean	Failure Data (t = 24 hours) Variance
A. Single Events							
1. Water Supply							
a. Screen Plugging	2.66×10^{-5}	4.32×10^{-9}	-	-			
b. Bypass Gates Failure			7.49×10^{-4}	4.01×10^{-7}			
TOTAL	-	-	-	-	System Failure	6.03×10^{-10}	9.54×10^{-18}
2. Piping Failures	1.12×10^{-8}	7.25×10^{-15}	-	-	System Failure	2.68×10^{-7}	4.18×10^{-12}
B. Triple Events							
1. Pump Trains							
a. Pump Fails to Start	-	-	6.41×10^{-3}	7.78×10^{-6}			
b. Pump Fails to Run	1.52×10^{-5}	2.09×10^{-10}	-	-			
c. Expansion Joint Ruptures	8.60×10^{-9}	6.00×10^{-15}	-	-			
d. Discharge Strainer Plugs	2.66×10^{-5}	4.32×10^{-9}	-	-			
e. Test Valve Open	1.99×10^{-8}	1.83×10^{-13}	-	-			
f. Check Valve Fails	-	-	7.02×10^{-5}	1.09×10^{-8}			
g. Discharge Valve Fails	7.40×10^{-8}	5.89×10^{-15}	-	-			
Single Train total	4.19×10^{-5}	3.44×10^{-10}	6.52×10^{-3}	7.32×10^{-6}			
(1/3) Pump Trains Total	-	-	-	-	System Failure	5.89×10^{-4}	7.37×10^{-8}
C. Test and Maintenance (with pump trains)	-	-	-	-			
D. Human Error							
1. Test Lineup Error (with pump trains)	-	-	-	-			
E. Common Cause	*						
F. Other	*						
G. Header Total					System Failure	5.89×10^{-4}	7.35×10^{-8}

*Negligible failure frequency.

TABLE 1.5.2.3.8-7E

INDIAN POINT 2 BOUNDARY CONDITION, LOSS OF ELECTRIC POWER AT TWO SWITCHGEAR BUSES, NUCLEAR HEADER

Component	Failure Data (Hourly) Mean	Failure Data (Hourly) Variance	Failure Data (Demand) Mean	Failure Data (Demand) Variance	System Effect	Failure Data (t = 24 hours) Mean	Failure Data (t = 24 hours) Variance
A. Single Events							
1. Water Supply							
a. Screen Plugging	2.66×10^{-5}	4.32×10^{-9}	-	-			
b. Bypass Gates Failure	-	-	7.49×10^{-4}	4.01×10^{-7}			
TOTAL					System Failure	6.03×10^{-10}	9.54×10^{-18}
2. Piping Failures	1.46×10^{-8}	1.24×10^{-14}	-	-	System Failure	3.51×10^{-7}	7.14×10^{-12}
B. Double Events							
1. Pump Trains							
a. Pump Fails to Start	-	-	6.41×10^{-3}	7.78×10^{-6}			
b. Pump fails to Run	1.52×10^{-5}	2.09×10^{-10}	-	-			
c. Expansion Joint Ruptures	8.60×10^{-9}	6.00×10^{-15}	-	-			
d. Discharge Strainer Plugs	2.66×10^{-5}	4.32×10^{-9}	-	-			
e. Test Valve Open	1.99×10^{-8}	1.83×10^{-13}	-	-			
f. Check Valve Fails	-	-	7.02×10^{-5}	1.09×10^{-8}			
g. Discharge Valve Fails	7.40×10^{-8}	5.89×10^{-15}	-	-			
Single Train Total	4.19×10^{-5}	3.44×10^{-9}	6.48×10^{-3}	7.31×10^{-6}			
2 of 3 Pump Trains					System Failure	1.0	0.0
2. EDG Flow Control Valve							
a. Valve Fails	-	-	7.47×10^{-4}	4.05×10^{-7}			
TOTAL	-	-	-	-	System Failure	9.44×10^{-7}	6.36×10^{-12}
C. Test (with pump trains)							
D. Human Error							
1. Mispositioned Switch	-	-	-	-	System Failure	1.11×10^{-5}	3.94×10^{-9}
2. Test Lineup Error (with pump trains)	-	-	-	-			
E. Common Cause	*						
F. Other	*						
G. Header Total	-	-	-	-	System Failure	1.0	0.0

*Negligible failure frequency.

TABLE 1.5.2.3.8-7F

INDIAN POINT 2 BOUNDARY CONDITION, LOSS OF ELECTRIC POWER AT TWO SWITCHGEAR BUSES, CONVENTIONAL HEADER

Component	Failure Data (Hourly) Mean	Failure Data (Hourly) Variance	Failure Data (Demand) Mean	Failure Data (Demand) Variance	System Effect	Failure Data (t = 24 hours) Mean	Failure Data (t = 24 hours) Variance
A. Single Events							
1. Water Supply							
a. Screen Plugging	2.66×10^{-5}	4.32×10^{-9}	-	-			
b. Bypass Gates Failure			7.49×10^{-4}	4.01×10^{-7}			
TOTAL	-	-	-	-	System Failure	6.03×10^{-10}	9.54×10^{-18}
2. Piping Failures	1.12×10^{-8}	7.25×10^{-15}	-	-	System Failure	2.68×10^{-7}	4.18×10^{-12}
B. Triple Events							
1. Pump Trains							
a. Pump Fails to Start	-	-	6.41×10^{-3}	7.78×10^{-6}			
b. Pump Fails to Run	1.52×10^{-5}	2.09×10^{-10}	-	-			
c. Expansion Joint Ruptures	8.60×10^{-9}	6.00×10^{-15}	-	-			
d. Discharge Strainer Plugs	2.66×10^{-5}	4.32×10^{-9}	-	-			
e. Test Valve Open	1.99×10^{-8}	1.83×10^{-13}	-	-			
f. Check Valve Fails	-	-	7.02×10^{-5}	1.09×10^{-8}			
g. Discharge Valve Fails	7.40×10^{-8}	5.89×10^{-15}	-	-			
Single Train Total	4.19×10^{-5}	3.44×10^{-10}	6.52×10^{-3}	7.32×10^{-6}			
(1/3) Pump Trains Total	-	-	-	-	System Failure	7.87×10^{-2}	2.79×10^{-4}
C. Test and Maintenance (with pump trains)	-	-	-	-			
D. Human Error							
1. Test Lineup Error (with pump trains)	-	-	-	-			
E. Common Cause	*						
F. Other	*						
G. Header Total					System Failure	7.87×10^{-2}	2.79×10^{-4}

*Negligible failure frequency.

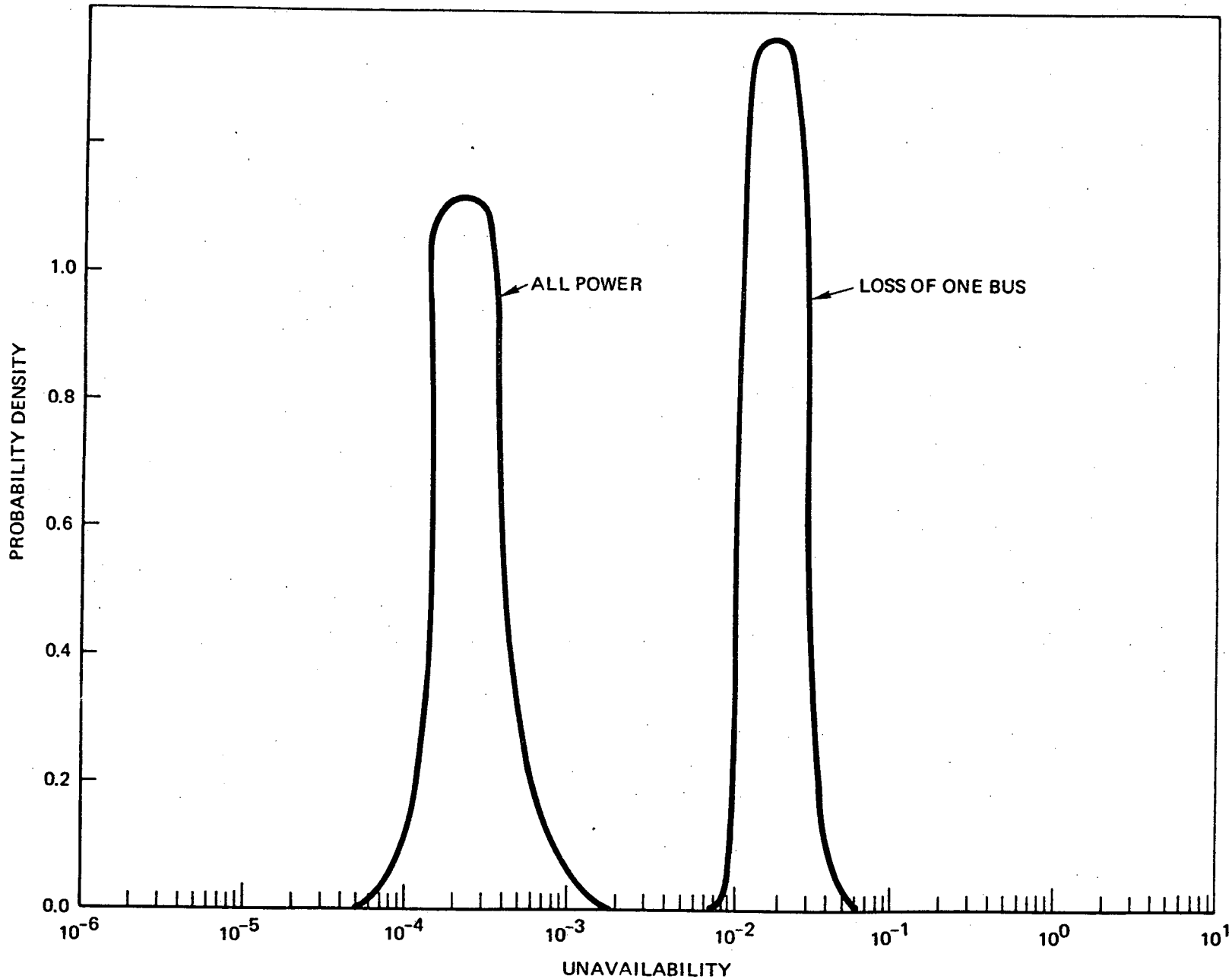


Figure 1.5.2.3.8-1. Probability Distribution of Indian Point 2 Service Water System Unavailability

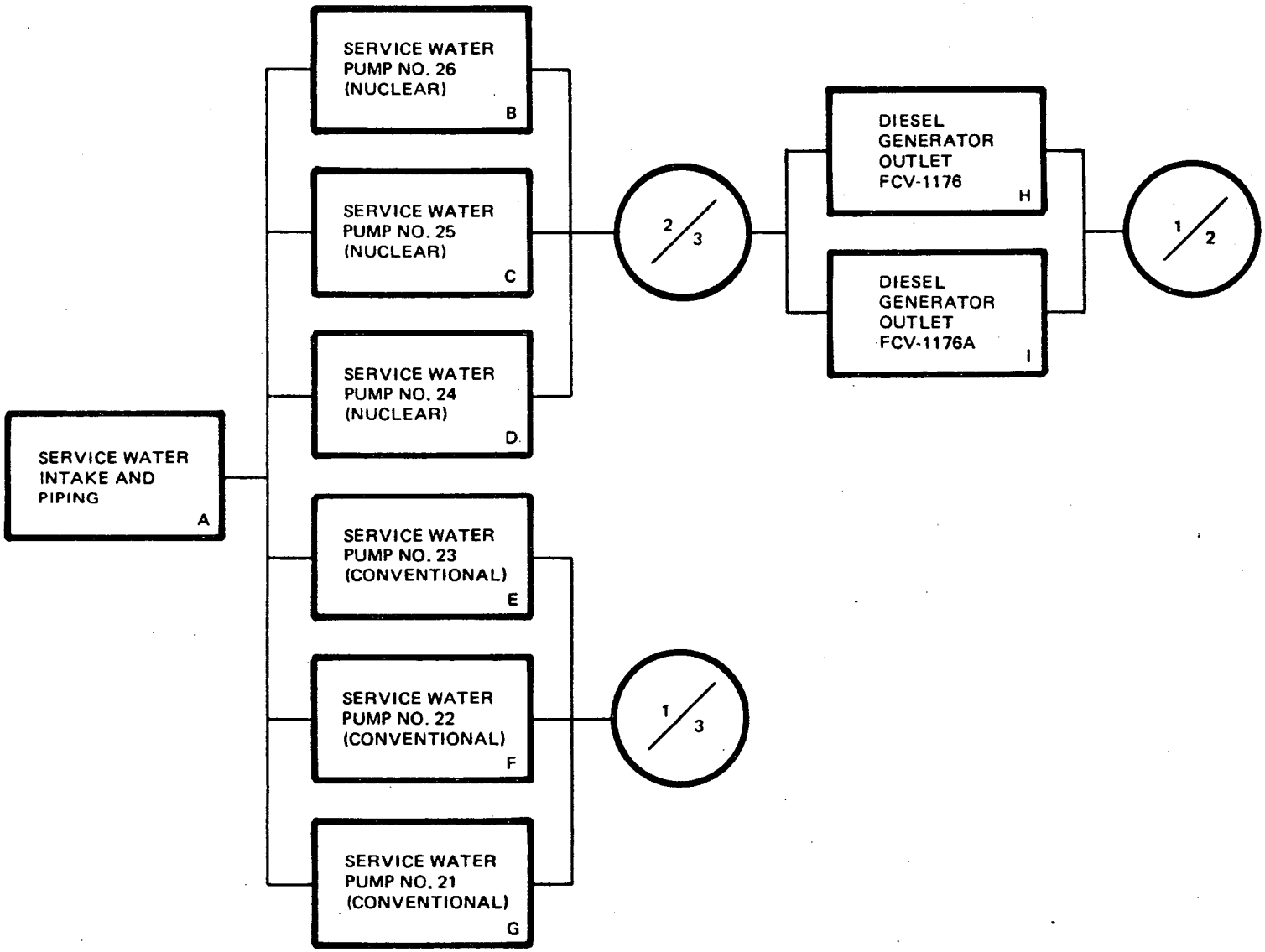


Figure 1.5.2.3.8-2. Indian Point 2 Service Water System Block Diagram

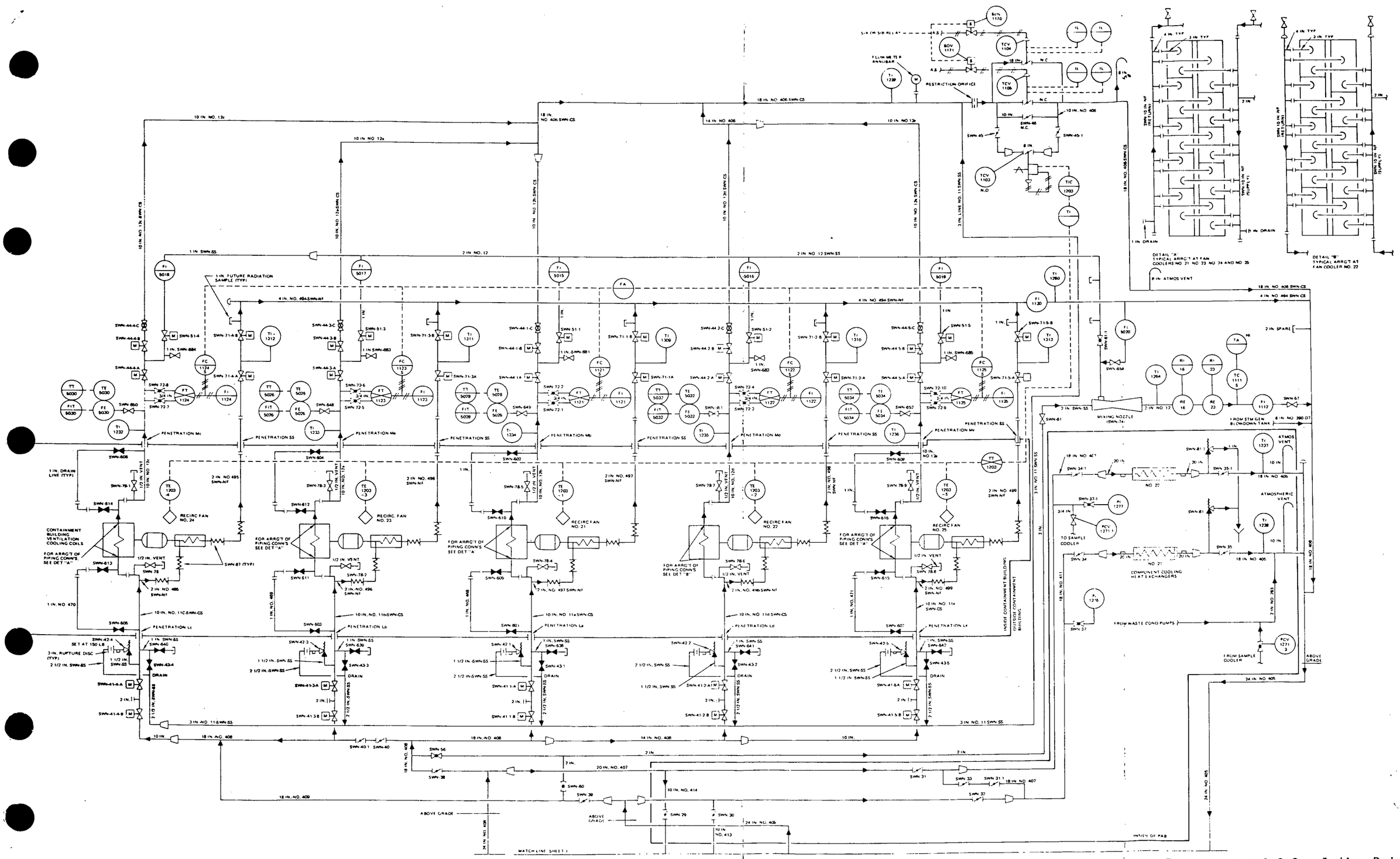


Figure 1.5.2.3.8-3. Indian Point 2
Simplified Schematic of Service Water System
(Sheet 1 of 2)

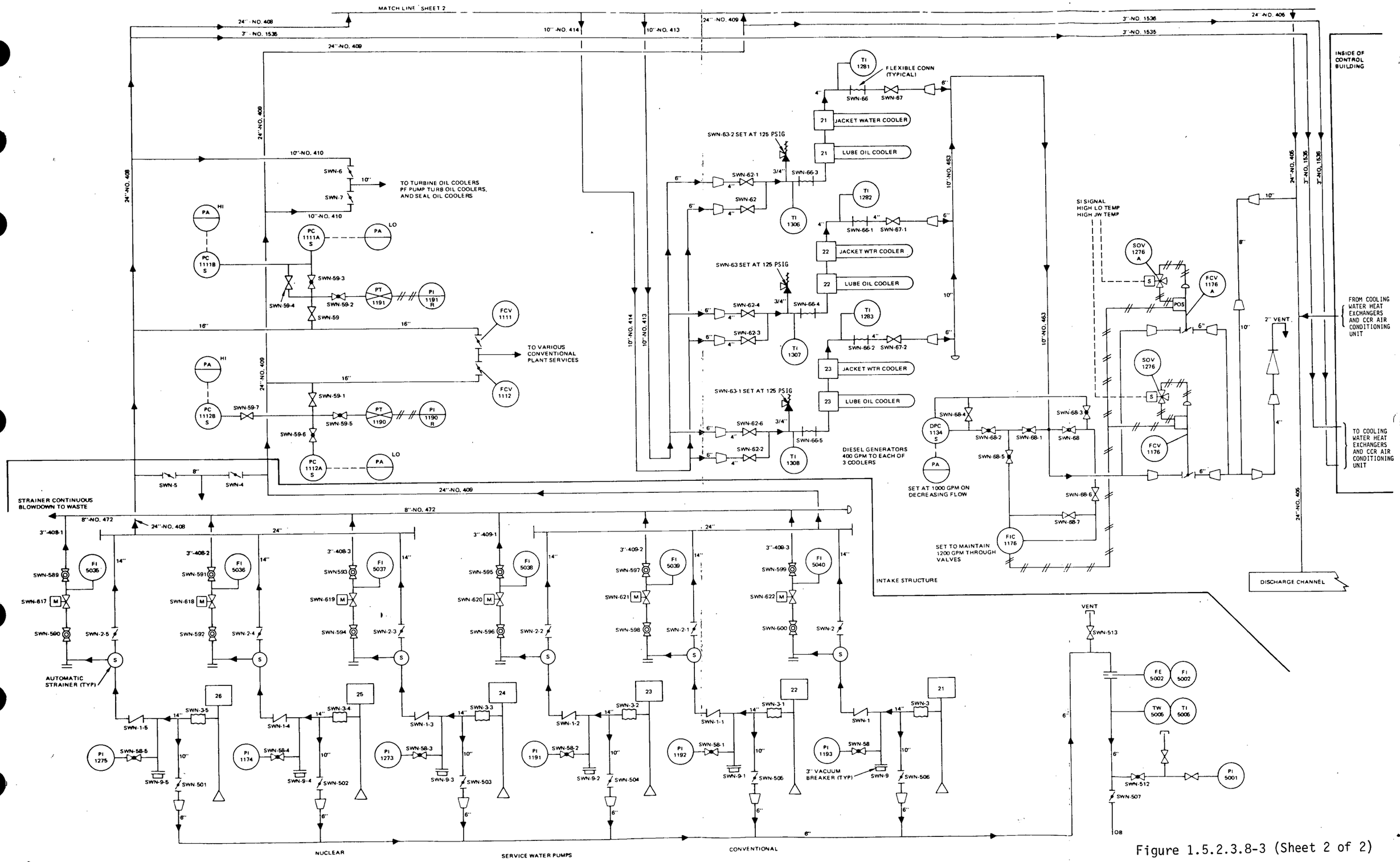
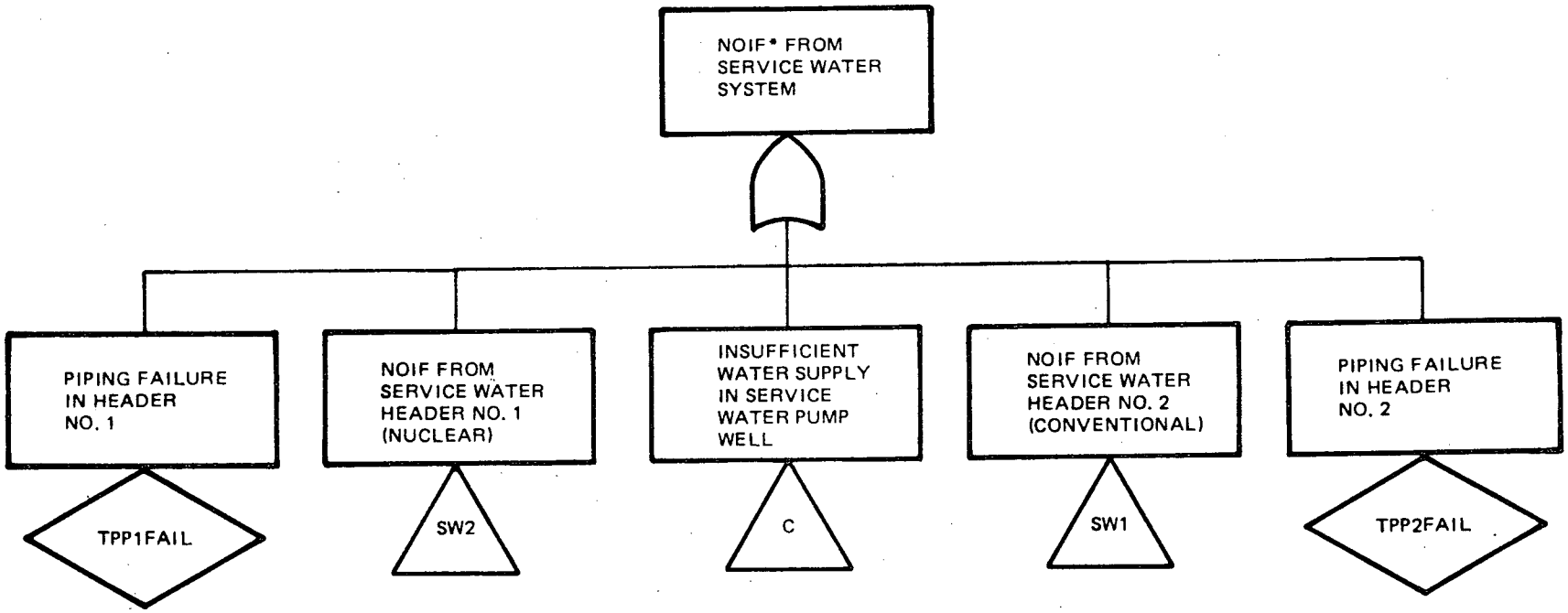
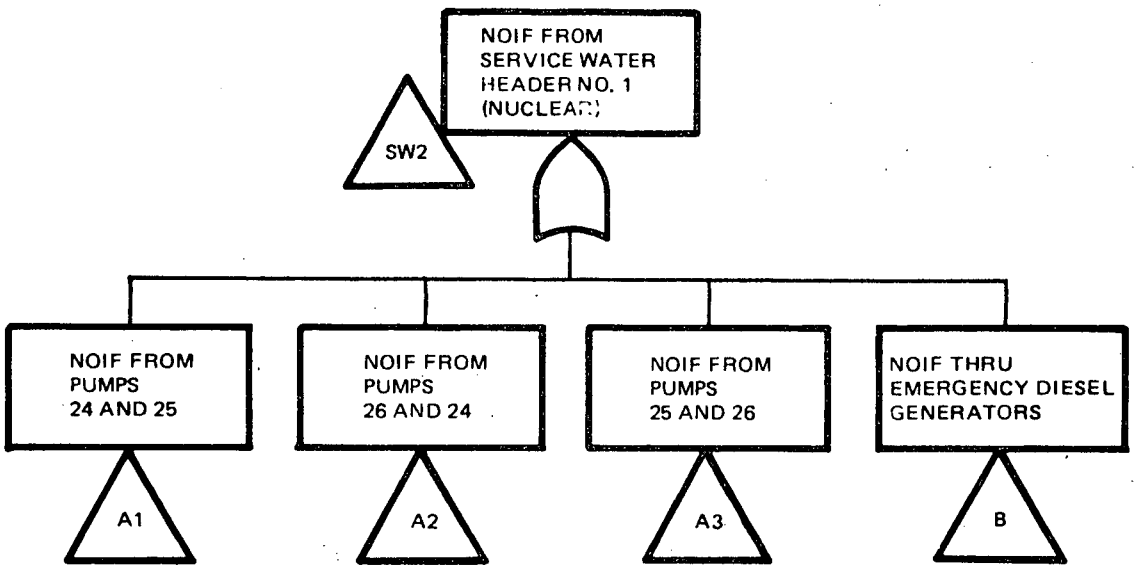


Figure 1.5.2.3.8-3 (Sheet 2 of 2)



*NOIF – NO OR INSUFFICIENT FLOW

Figure 1.5.2.3.8-4. Indian Point 2 Service Water System Fault Tree (Sheet 1 of 6)



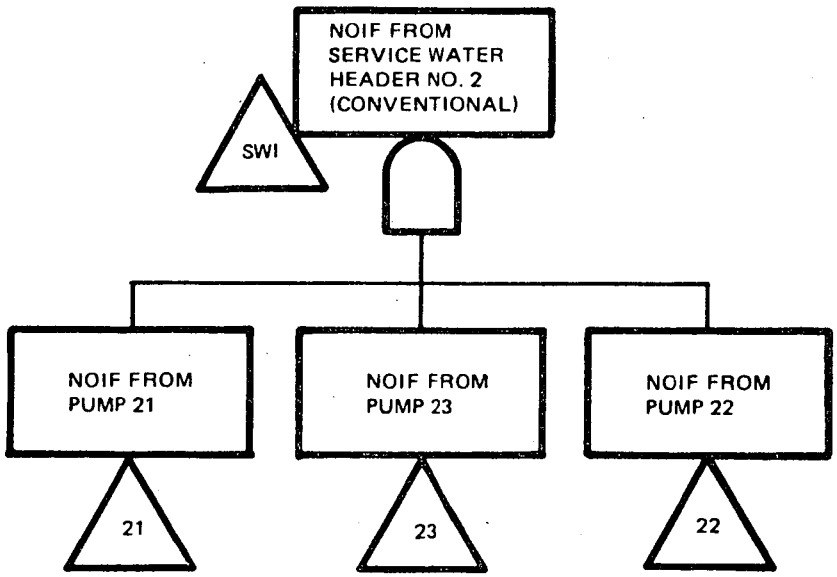


Figure 1.5.2.3.8-4 (Sheet 2 of 6)

α	γ	δ	ϵ	ϕ	β	Δ
A1	24	25	3A/2A	3	23A	502
A2	26	24	5A	5	25A	503
A3	25	26	6A	4	26A	501

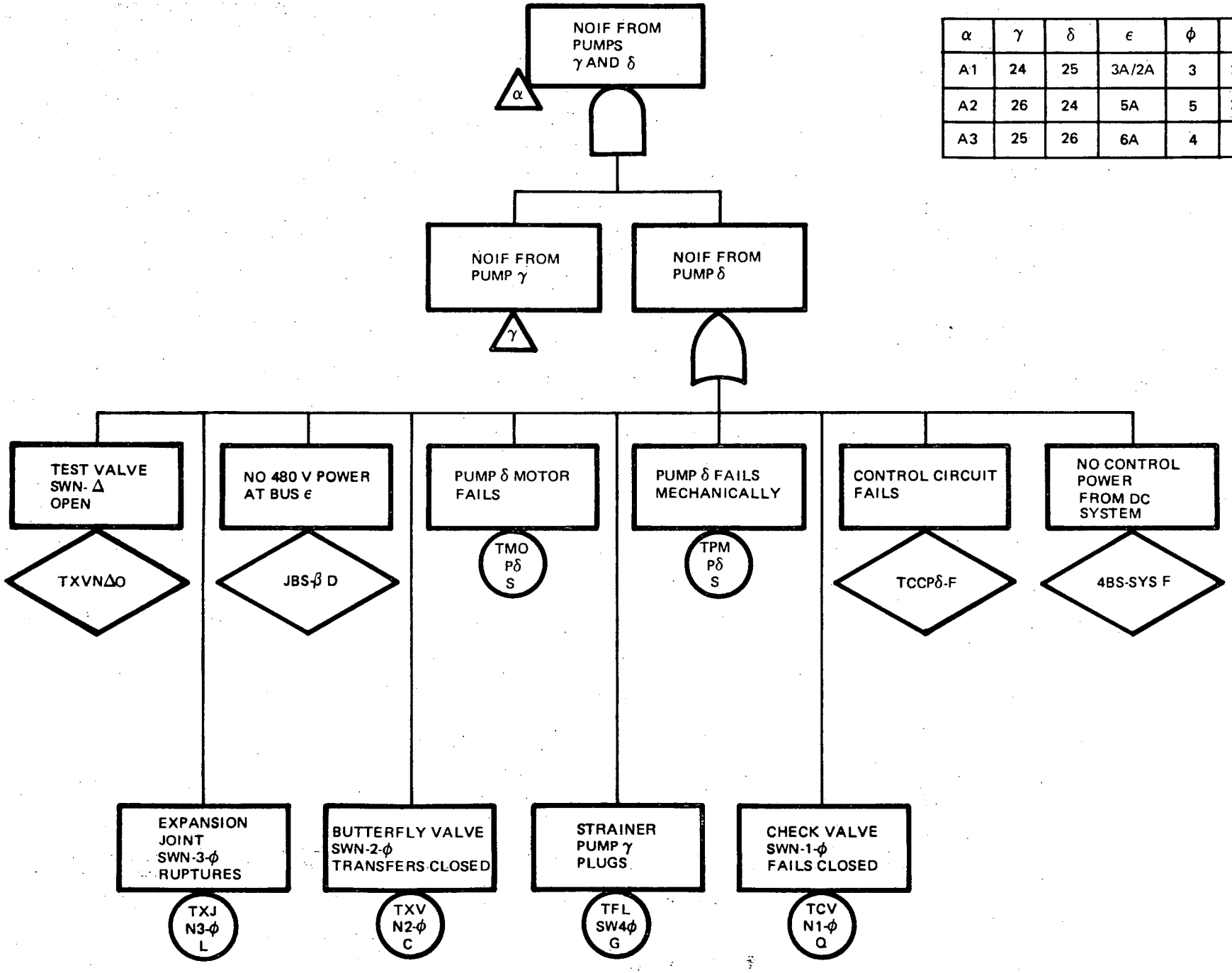


Figure 1.5.2.3.8-4 (Sheet 3 of 6)

γ	θ	ϕ	β	Δ
24	5A	3	25A	503
26	6A	5	26A	501
25	3A/2A	4	23A	502
21	5A	–	25A	506
23	6A	2	26A	504
22	2A/3A	1	22A	505

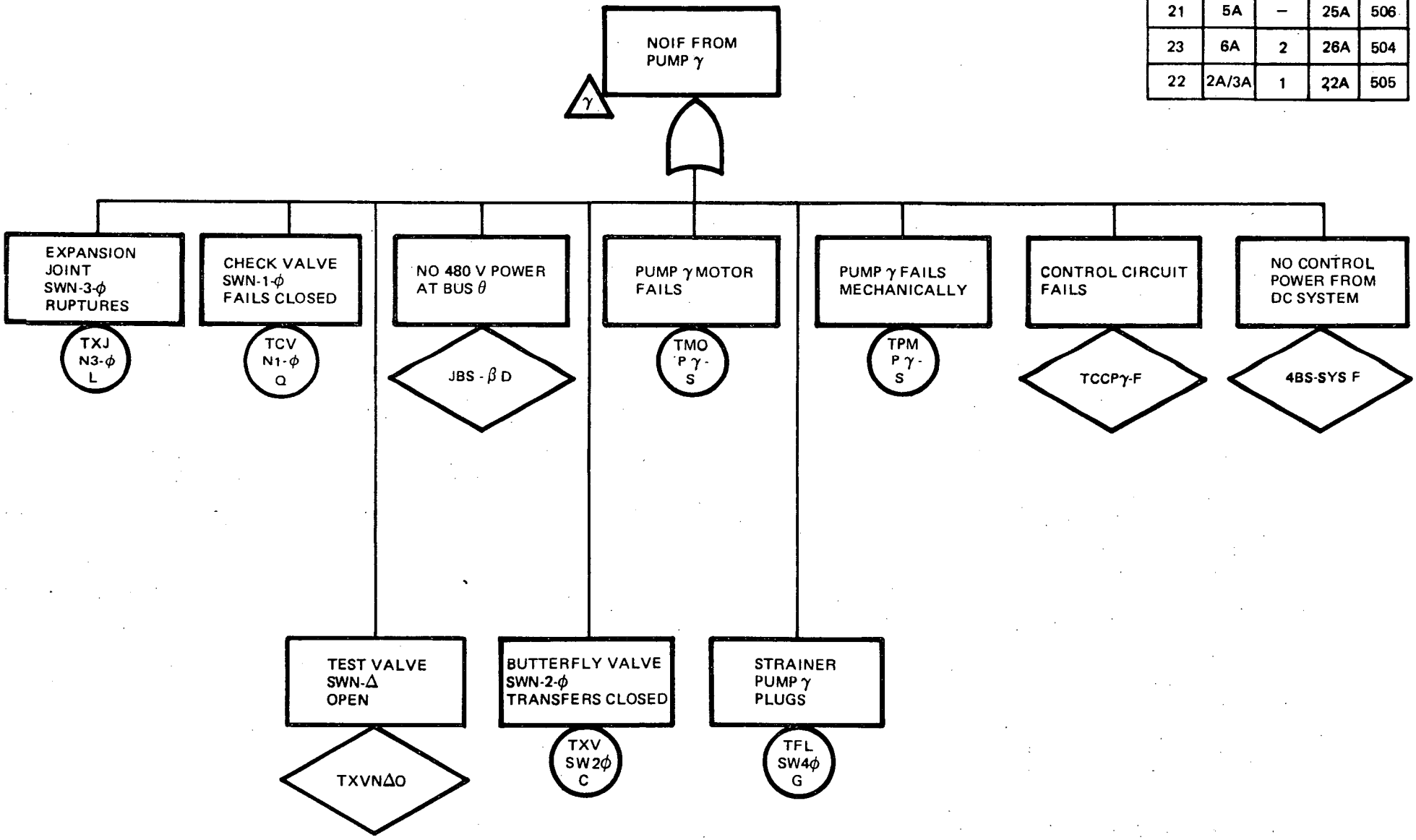


Figure 1.5.2.3.8-4 (Sheet 4 of 6)

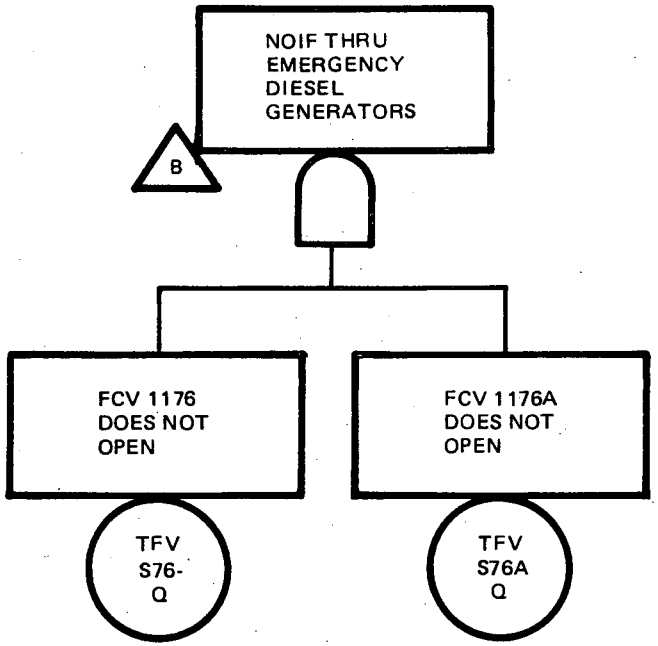


Figure 1.5.2.3.8-4 (Sheet 5 of 6)

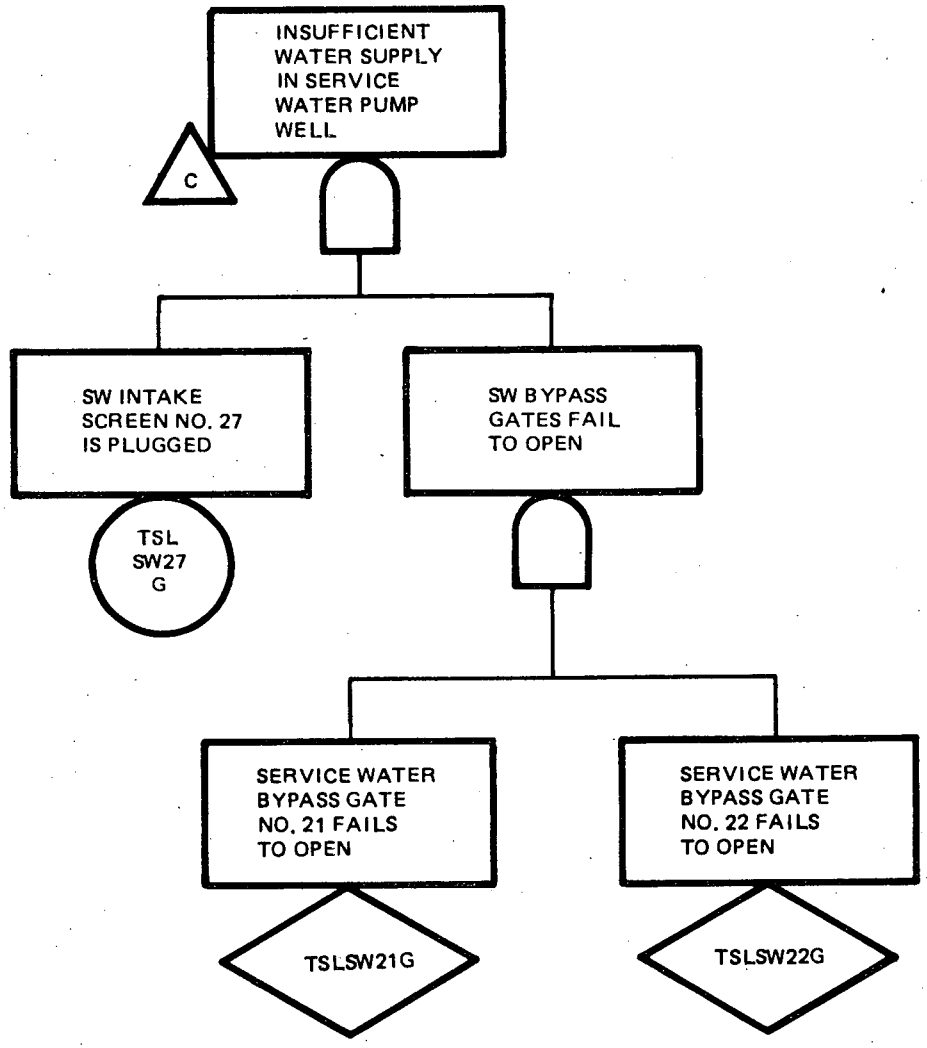


Figure 1.5.2.3.8-4 (Sheet 6 of 6)

1.5.2.3.9 Indian Point 3 Auxiliary Feedwater System

1.5.2.3.9.1 Summary.

1.5.2.3.9.1.1 Introduction. The Indian Point Unit 2 auxiliary feedwater system (AFWS) is a heat removal system for the steam generators. It can operate in conjunction with, or independently from, the main feedwater system for emergencies or as optional equipment in startup, shutdown, or hot standby conditions.

The AFWS analysis determines the system minimal cutsets; i.e., the smallest groups of combined failure modes that lead to system failure. The analysis also catalogs the causes for specific failure modes and evaluates their probability of occurrence. The cause categories are unrecoverable random independent failures, unrecoverable test and maintenance, independent human error, common cause, and other.

The analysis is based on the system as it exists in three given electrical states. These are:

1. Full Power. The system has full electrical capabilities.

2. One Bus Unavailable. The system has one main bus not functioning. (Four buses supply power to the AFWS but only two are of primary concern because the other two supply components whose failure state does not prevent the system from operating.)

3. No Power. The system has no electric power.

The data used for calculations reflect the generic data (prior), as well as the plant specific data (posterior). These data were analyzed using computer codes and fault trees to produce quantitative evaluations.

1.5.2.3.9.1.2 Boundary Conditions. The boundary of the analysis is presented in Figure 1.5.2.3.9-1. The turbine steam supply from the steam generators and all the AFWS components are included directly in the analysis. The water supplies are not analyzed in detail. However, the piping systems and valves that deliver water or steam to and remove them from the AFWS are included. Electrical power supplies are outside the boundary of the analysis and are considered later in Cases 1, 2, and 3. The AFWS actuation signal is also outside the boundary of the analysis. The analysis is conducted conditional on the presence of an AFWS actuation signal. The electrical system is discussed in the electrical section, and the AFWS actuation signal in the safeguards actuation section. Finally, some human interactions are included in the analysis. The human interactions concerning test and maintenance, as well as operator response to system failure on demand, are considered.

1.5.2.3.9.1.3 Results. The AFWS unavailability was calculated for the three states of the electric power system. The results are shown in Table 1.5.2.3.9-1. Table 1.5.2.3.9-1 indicates that the state of the electric power system is very important. The AFWS depends primarily on two electrical buses for power and is designed to function without electric power. However, loss of all electric power increases the system unavailability because the two motor-driven pumps would become inoperative.

The dominant contributors to unavailability are different for each state of the electric power system. The dominant contributors for the full power state are:

- Nonrecoverable Random Failures. Failure of the condensate storage tank and city water supplies (mean unavailability: 1.02×10^{-5}; approximate unavailability contribution: 51.5%).

- Independent Human Error. Failure of the operator to valve in the city water supply along with a failure of the condensate storage tank water supply (mean unavailability: 5.47×10^{-6}; approximate unavailability contribution: 27.9%).

- Common Cause. Common cause failure to restore the motor and turbine-driven pump discharge valves after tests (mean unavailability: 2.48×10^{-6}; approximate unavailability contribution: 12.7%).

For the case in which one electrical bus was not functioning, the dominant contributors are:

- Independent Human Error. Operator failure to start* the turbine-driven pump and to open valves 405A, B, C, and D along with a failure of the motor-driven pump (mean unavailablity: 4.90×10^{-5}; approximate unavailability contribution: 30.2%).

- Test and Maintenance. Turbine pump maintenance along with a failure of the other motor-driven pump (mean unavailability: 3.19×10^{-5}; approximate unavailability contribution: 20.0%).

- Independent Human Error. Operator failure to start the turbine-driven pump and to open valves 405A, B, C, and D along with maintenance on the motor-driven pump (mean unavailability: 1.60×10^{-5}; approximate unavailablity contribution: 9.9%).

- Nonrecoverable Random Failure. Failure of turbine and motor-driven pump trains (mean unavailability: 1.45×10^{-5}; approximate unavailability contribution: 9.0%).

*Throughout this analysis, failure to start the turbine-driven pump means failure to bring pump up to speed with hand controller because the pump will run at minimum speed when given an automatic start signal.

- Independent Human Error. Operator failure to start the turbine-driven pump and to open valves 405A, B, C, and D along with failure of either set of discharge valves on the remaining motor-driven pump (mean unavailability: 1.26×10^{-5}; approximate unavailability contribution: 7.8%).

- Nonrecoverable Random Failure. Failure of the CST and city water supplies (mean unavailability: 1.02×10^{-5}; approximate unavailability contribution: 6.3%).

- Test and Maintenance. Turbine-driven pump maintenance along with a failure in either set of discharge valves on the remaining motor-driven pump (mean unavailability: 8.22×10^{-6}; approximate unavailability contribution: 5.1%).

For the case in which there is no electric power, the dominant contributors to unavailability are:

- Independent Human Error. Failure of the operator to start the turbine-driven pump (mean unavailability: 7.00×10^{-3}; approximate unavailability contribution: 51.1%).

- Test and Maintenance. Turbine-driven pump maintenance (mean unavailability: 4.56×10^{-3}; approximate unavailability contribution: 33.3%).

- Nonrecoverable Random Failures. Failure of the turbine-driven pump train (mean unavailability: 2.07×10^{-3}; approximate unavailability contribution: 15.1%).

The results presented in this section show that the Indian Point 2 AFWS is very reliable in the emergency mode. Redundancy, separation, availability during testing, and recoverability make the system sound. Figure 1.5.2.3.9-2 shows the curves for the three power states discussed in this analysis. The results are based on the failure of the AFWS to deliver at least 150 gpm to each of two steam generators. Based on normal steam generator water inventories, approximately 30 minutes are available from the time of reactor trip until auxiliary feedwater is required. The dominant contributors to conditional unavailability are human error (inaction), test and maintenance, and nonrecoverable random failures.

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1.5.2.3.9.2 System Description.

1.5.2.3.9.2.1 System Function. The AFWS emergency function provides heat removal for the primary system when the main feedwater system is not available. A simplified block diagram of the AFWS is shown in Figure 1.5.2.3.9-3. Water is supplied to each of four steam generators through three pumps. The AFWS must provide cooling during small loss of coolant accidents and during transients that lead to a loss of main feedwater. The AFWS provides initial cooling to prevent overpressurization of the primary system and has sufficient preferred water supply to remove the residual heat generated by the reactor for at least 24 hours for hot shutdown conditions. The system is also used during normal plant startup, shutdown, and hot standby conditions. For success under emergency conditions, flow from at least one pump must be delivered to at least two steam generators (150 gpm to each) within 30 minutes of the initial demand.

1.5.2.3.9.2.2 System Operation. A simplified diagram of the AFWS for the Indian Point Unit 2 is presented in Figure 1.5.2.3.9-4.

The AFWS consists of two subsystems. One subsystem uses two motor-driven pumps, each with a capacity of 400 gpm. The discharge piping is arranged so that each pump supplies two steam generators. The other subsystem uses a steam turbine-driven pump. The steam for this pump can be supplied from steam generators 22 and 23 upstream of the main steam isolation valves. A pressure reducing control valve reduces the pressure to the 600 psi design value of the turbine. This system supplies a total of 800 gpm to all four steam generators.

Redundant water supplies are available to the AFWS. The primary source is gravity feed from the seismic category I condensate storage tank, which has a total capacity of 600,000 gallons. Of this volume, at least 360,000 gallons are dedicated for AFWS use. Availability of water from this source is guaranteed by LCV-1158, which closes when the quantity of water in the tank drops to 360,000 gallons, isolating the condensate storage tank outlet from all other systems. Redundant level indicators and control room alarms are provided for the condensate storage tank. When LCV-1158 closes, water supply to the main condensers is prevented and the availability of a sufficient quantity of water to remove the residual heat generated by the reactor for at least 24 hours at hot shutdown conditions is ensured. Two locked open manual valves, CT-6 and CT-64, are present in series along the main supply line from the condensate storage tank. Output from redundant position switches on both valves are displayed and alarmed in the control room.

Each auxiliary feedwater pump takes suction on the header through a check valve and a locked open manual gate valve (CT-32, CT-33; CT-26, CT-27; CT-29, CT-30). Individual flow elements are provided on the

suction to each of the two motor-driven pumps (21 and 23). These elements provide a low suction flow pump trip feature for each of the motor-driven pumps. Pump suction pressure is indicated in the central control room for each pump by PI-1263-R, PI-1264-R, and PI-1265-R.

The secondary water supply for the auxiliary pumps is the 1.5 million gallon city water storage tank which is shared by Units 2 and 3. A manual gate valve (CT-49) that is normally open is located in the city water supply line buried outside the auxiliary pump building. Each pump is supplied from a header through a check valve and fail close air-operated control valve which is normally closed (CT-25, PCV-1187; CT-28, PCV-1188; CT-31, PCV-1189). These valves are controlled manually by a switch located in the central control room. This switch operates the solenoid, applying or removing air from the valve. The valve position is indicated in the control room.

Discharge from each of the pumps is routed to the steam generators as illustrated in Figure 1.5.2.3.9-4. Steam generators 21 and 22 are supplied by motor-driven auxiliary feedwater pump 21. Steam generators 23 and 24 are supplied by motor-driven auxiliary feedwater pump 23. All four steam generators are supplied by the turbine-driven auxiliary feedwater pump 22.

Each of the auxiliary feedwater lines has an air-operated fail open flow control valve for feedwater regulation (FCV-405A, B, C, D, and FCV-406A, B, C, D). The feedwater flow control valves in the pump sections are normally closed. Each of these eight lines also includes a check valve and two locked open manual isolation valves in series with the air-operated valve. A common flow transmitter for each steam generator indicates flow in the central control room from the header common to the motor and turbine-driven pump sections. Pump discharge pressure is provided both locally and in the control room. Recirculation lines, which are provided for pump protection, are located upstream of the check valves at the pump discharges (BFD-31, 34, 39) and are routed back to the condensate storage tank.

Level in the steam generators is maintained manually from the control room by positioning the flow control valves. Each valve can be positioned from the control room by electric/air converters. Air to these valves and to the city water supply valves described previously is from a common header which is supplied by air compressors powered from 480V switchgear buses. The air supply to the valves is automatically backed up by an emergency high pressure nitrogen (bottle) system.

All pneumatic instruments associated with the auxiliary pump flow controls have an automatic nitrogen backup. Three nitrogen bottles are located inside the auxiliary feed pump room. These bottles are connected to the instrument air supply downstream of a check valve. A pressure regulator set at 50 psig will feed nitrogen into the instrument air supply system whenever the normal air supply pressure drops below this setting. A pressure switch, PC-1355-S, located at the bottles will

annunciate in the control room to warn the operator when the bottles need to be changed. A nitrogen bottle is also located in the auxiliary pump room to provide an emergency air supply to PCV-1139 to control steam flow to the turbine-driven auxiliary feedwater pump.

In addition to remote control from the control room, all the AFWS pumps and regulating valves can be operated locally in the auxiliary feedwater building.

The AFWS is not designed to automatically terminate feedwater flow to a depressurized steam generator and provide flow to the intact steam generator. The operator must do this.

1.5.2.3.9.2.2.1 Motor-driven auxiliary feedwater pump subsystem. The motor-driven pumps are Ingersoll-Rand Company 3HMTA, nine-stage, horizontal, split case centrifugal units. Each supplies 400 gpm of water at a head of 1,350 psi. The motor drives are furnished by Westinghouse Electric Corporation.

Auxiliary feedwater pumps 21 and 23 are driven by motors supplied from independent 480V emergency buses 3A and 6A, respectively. Control switches exist both locally and in the central control room on the condensate and feedwater supervisory panel. The local switches allow "Start and Stop" pushbutton operation of the pumps. The switches in the control room have three positions, "On-Auto-Trip." The following conditions will automatically start the motor-driven pumps:

- The loss of either of two main feedwater pumps.
- A two out of three coincidence of low-low steam generator level in any one of four steam generators.
- If there is a unit trip which is initiated by a safety injection signal, the following will occur:
  - All buses will clear, tripping the pumps if they are on the line.
  - The pumps will receive a start signal as part of the automatic safeguard bus reloading sequence.
- Unit trip plus loss of offsite power with no safety injection signal. This will provide both pumps with a start signal after the diesels have tied into the 480V buses. A time delay is associated with starting the pumps to allow for loading of the diesels.

Undervoltage on either bus 3A or 6A will trip the pump fed by the bus. The generation of a safety injection signal will trip the pumps if they are on and will subsequently reload them.

The following indications and alarms are provided in the central control room to monitor the pumps:

- On-off-auto trip lights.
- Lock off alarm.
- Auto trip alarm.
- On local control alarm.

Each motor-driven pump has a pressure sustaining control system to prevent the pump from "running out" on its curve. As the discharge pressure of the pump decreases below the setpoint, PT-406A for pump 21 and PT-406B for pump 23 will each generate a signal that will override those from the flow controllers on the condensate and feedwater supervisory panel. The signal will modulate the valves toward the closed position until the pressure is restored in the discharge line that has low pressure.

1.5.2.3.9.2.2.2 Turbine-driven auxiliary feedwater pump subsystem. The full size, turbine-driven pump is a Worthington Corporation 4-WT-127 horizontal, multistage, centrifugal pump with a capacity of 800 gpm at 1,350 psi. The turbine drive is a horizontal axial flow, noncondensing unit rated at 970 hp at 3,570 rpm. The main steam system ahead of the main steam isolation valves supplies steam for the turbine.

Two temperature controlled air-operated shutoff valves, PCV-1310A and PCV-1310B, are mounted in series in the steam line to the turbine-driven pump. These valves protect the motor-driven pumps from becoming inoperable in the unlikely event that the pump steam supply line in the auxiliary feedwater pump room ruptures.

During turbine operation, the steam supply pressure is regulated by PCV-1139. This pressure control valve maintains a 600 psig steam pressure to the turbine. Pressure controller 1176-S senses the downstream pressure and generates a signal to the positioner. The control signal generated by the positioner is then applied to the diaphragm of PCV-1139 through the start solenoids. Pressure controller 1176-S will also alarm low pressure at 550 psig in the central control room. Once the pressure has been reduced, the steam enters the turbine steam chest which contains the governor and turbine trip valves.

The turbine-driven pump is a variable speed device, whereas the two motor-driven pumps are constant speed devices. The speed of the turbine-driven pump is controlled by a remote pneumatic speed changer (HC-1118) that is located on the condensate and feedwater supervisory panel in the central control room. The speed changer is designed to operate over an entire speed range of zero to 100%.

Pressure reducing valve PCV-1139 is used as the steam shutoff and start valve for the auxiliary feed pump turbine. "Trip-Auto-On" switches control the operation of this valve. One switch is located in the central control room, and one is in the auxiliary boiler feed pump building. These switches control the position of the solenoid valves mounted on the air inlet to the valve actuator. In their deenergized state, these solenoid valves allow the positioner output to open the

valve. Normally, the valve is maintained in standby and the control switches are in "Auto." In this state, the positioner output is cut off and full instrument air pressure is applied to the valve actuator that holds the valve closed. The solenoid valves will be automatically deenergized and the turbine-driven pump started by either of the following:

1. A two out of three coincidence of low-low water level in any two of the four steam generators.

2. Loss of offsite power concurrent with a main turbine generator trip (provided that a safety injection signal does not exist).

The turbine governor valve is controlled by a governor and speed changer. The speed changer can be operated locally or from the control room by HC-1118. A trip valve has been provided to immediately shut down the turbine on an overspeed of 4,516 rpm. Operator action is required locally at the turbine to reset the overspeed trip. Turbine speed is indicated locally and in the central control room. Under normal conditions, the operator must use HC-1118 to bring the turbine up to speed; the automatic signal to PCV-1139 will not do this. Loss of air to HC-1118 causes failure of the speed changer in the full closed position.

1.5.2.3.9.2.3 Supporting Systems. The AFWS is started by a signal from the safeguards actuation system (SAS), which starts the motor-driven auxiliary feedwater pump. Manual actuation is also possible from the control room. Power supplies for each component requiring electrical power are identified in Table 1.5.2.3.9-2. The piping analysis is shown in Table 1.5.2.3.9-3. The instrument air system is the primary air supply for controlled operation of all air-operated valves in the system and the speed control system on the auxiliary feedwater turbine. The city water supply system is required as a secondary supply for the system.

The operator also plays an integral role in the operation of the AFWS. Specifically, the operator must open the four normally closed air-operated flow control valves (FCV-405A, B, C, and D) on the feed lines from the turbine-driven auxiliary feedwater pump when this pump is needed. This can be done from the control room. In addition, the operator must open the three normally closed air-operated stop valves (PCV-1187, 1188, and 1189) on the supply lines from the city water supply to the auxiliary feed pumps when there is loss of flow from the condensate storage tank. This can be done from the control room under normal conditions. However, because the city water valves are fail closed valves, when there is loss of AC power from the 120 VAC distribution panel 21 or loss of instrument air and backup nitrogen to these valves, the operator must manually open them in the pump room. Furthermore, because the auxiliary feedwater turbine speed control system (HC-1118) depends on instrument air, the operator must also operate the turbine-driven pump in the pump room when there is loss of instrument air.

1.5.2.3.9.2.4 Test Requirements. The following procedures form the test schedule for Indian Point Unit 2. The procedure numbers are in parentheses. Details of the required testing frequency and the indirect testing of all AFWS components are provided in Table 1.5.2.3.9-4. The numbers in the table are conservative and, in many cases, do not include indirect testing which ocurrs during periodic shutdowns. The major test procedures and their general application are outlined below:

- Each motor-driven auxiliary feedwater pump is started at least once a month (PT-M23). Full flow is established to the steam generators once every refueling (PT-R7).

- The steam turbine-driven auxiliary feedwater pump is started at least once a month (PT-M37) with full flow established to the steam generators once every refueling (PT-R22).

- Various safety related systems, including the auxiliary feedwater discharge valves, the turbine pump air-operated steam control valve, and the city water supply air valves are stroked every 3 months (PT-Q13).

- The auxiliary feedwater pump turbine manual overspeed trip is tested on a variable schedule. In first test, the manual overspeed turbine trip level is used to trip the turbine during operation (PT-V6). The other test runs the turbine up until it overspeeds to test the setpoint of the mechanical overspeed trip mechanism. The turbine is uncoupled from the pump during this second test (PT-V8). Following both tests, the trip mechanism must be reset.

The automatic initiation of the two motor-driven auxiliary feedwater pumps is tested on receipt of an engineered safeguards signal and is verified at refueling (i.e., approximately 18-month intervals).

1.5.2.3.9.2.5 Maintenance Requirements. The plant technical specifications limit the time that an auxiliary feedwater pump or pump train may be out of service to 72 hours. Further, a minimum of 360,000 gallons of water in the condensate storage tank and a backup supply from the city water supply must be available. If during power operation these conditions cannot be met within 72 hours, the reactor must be placed in the hot shutdown condition within the next 12 hours and subsequently cooled below 350°F using normal operating procedures.

1.5.2.3.9.3 Logic Model.

1.5.2.3.9.3.1 Top Events. For success under emergency conditions, flow from at least one pump must be delivered to at least two steam generators (150 gpm to each) within 30 minutes of the initial demand. Success of the system is examined for the conditional probabilities associated with loss of the various states of the electric power system, instrument air system, maintenance, and human error.

1.5.2.3.9.3.2 System Fault Tree. A fault tree was constructed to model the failures that must occur to prevent successful system operation. The top event is defined as "AFWS Failure to Deliver at Least 150 gpm to Each of Two Steam Generators." Sufficient flow is defined as the flow delivered from at least one pump train to at least two steam generators. The fault tree shows that there must be insufficient flow to at least three of the four steam generators for the system to fail. In each case, this requires that there is no flow or insufficient flow through the steam generator inlet valve section, or that there is no flow or insufficient flow delivered to that section. Moreover, there must be no flow or insufficient flow from either motor-driven pump (i.e., both must fail) and no flow or insufficient flow from the turbine-driven pump. Finally, there must be no water from either of the two potential water sources. This complete fault tree model is presented in Figure 1.5.2.3.9-5 which models the system down to the level of major components. Included were the pumps, valves, electrical supply, motor operators, and turbine and control mechanisms. Drain lines and valves, piping, and connected lines which are small, i.e., those whose failure would not significantly affect the system, were not modeled. The AFWS is modeled from the water sources to the steam generators. Electrically, it is modeled from the bus to the system.

1.5.2.3.9.3.3 Fault Tree Coding. Table 1.5.2.3.9-5 is a list of basic events, their failure modes, their corresponding codes, and unavailability (or failure probability on demand).

1.5.2.3.9.3.4 Minimal Cutsets. The minimal cutsets were identified using FATRAM (part of RAS). The valid minimal cutsets for each electric power state differed because some of the cutsets changed when a power state was given as a condition. Generally, this is why loss of electric power increases unavailability. For example, a three-event cutset could be reduced to a two-event cutset. One of the members of the cutset no longer has a fractional unavailability, but has been defined as unavailable. Therefore, the new two-event cutset will have a higher unavailability. This will lead to a higher system unavailability.
Table 1.5.2.3.9-6 lists the "base" minimal cutsets. "Base" in this case means the group of minimal cutsets for the whole fault tree without any reduction because of definitions of state.

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1.5.2.3.9.4 Quantification.

1.5.2.3.9.4.1 General. The numbers that appear in the quantification of the AFWS were calculated by a method of histogram multiplication. The histograms for the basic components are created from a mean and variance for those components. The basic components are then built into larger components (supercomponents) as needed to evaluate the cutsets from the fault tree. Tables 1.5.2.3.9-7A through 1.5.2.3.9-7I is a collection of these supercomponents used in the AFWS calculations. Tables 1.5.2.3.9-8A through 1.5.2.3.9-8L shows how each supporting row and column of Table 1.5.2.3.9-1 was created, using the supercomponents and other needed data.

1.5.2.3.9.4.2 Random Failures (See Tables 1.5.2.3.9-8A, 1.5.2.3.9-8B, and 1.5.2.3.9-8C). Random system failures reflect the system malfunctions that result from random component failures. The coincidental failure of each component in an AFWS cutset causes a random system failure. These random failures can be divided into two types: nonrecoverable and recoverable. These failures do not include, and should be differentiated from, test and maintenance failures, common cause failures, and independent human errors.

Nonrecoverable random failures for the AFWS are those which cannot be repaired within a specificied time. The time depends on system demands and component capabilities.

Recoverable failures require action for success when they occur. Section 1.5.2.3.9.4.5 on human interaction elaborates on recovery by system repair.

1.5.2.3.9.4.3 Test and Maintenance (See Tables 1.5.2.3.9-8D, 1.5.2.3.9-8E, and 1.5.2.3.9-8F).

1.5.2.3.9.4.3.1 Testing. Testing the AFWS consists primarily of surveillance testing to meet the plant technical specifications and ASME Section XI requirements.

Monthly testing is performed on each AFWS pump. For each pump test the manual gate valves in the pump discharge lines are closed and the pump is started manually from the control room or the local control panel. Each pump is then run 20 to 30 minutes to allow the system to stabilize. Required pump data are read and recorded. The AFWS pump test is then stopped and the manual gate valves are opened fully. For successful completion of the monthly pump test, the AFWS pump must develop minimum differential pressure on recirculation flow.

The condensate storage tank is continuously monitored by redundant indicators and alarms to verify the volume of water it contains.

The other components in the system have different test intervals, indicate in Table 1.5.2.3.9-8.

1.5.2.3.9.4.3.2 Maintenance. The plant technical specifications limit the time an AFWS pump or pump train may be out of service to 72 hours. After this time the plant must shut down.

Packing replacement and adjustment is the main reason for valve maintenance. In most cases, this maintenance can be performed with the valve in the normal position for system operation (fully open or fully closed). Valve repairs requiring disassembly of the valve, although not frequent, may have a major impact on system availability because of the system isolation requirements for safe performance of this maintenance. Those valves which require full AFWS shutdown for repair also require a plant shutdown (per technical specifications) and, therefore, do not contribute to the maintenance unavailability of the AFWS. Those valves requiring maintenance and that need only a single AFWS pump train shut down contribute to maintenance unavailability of the AFWS.

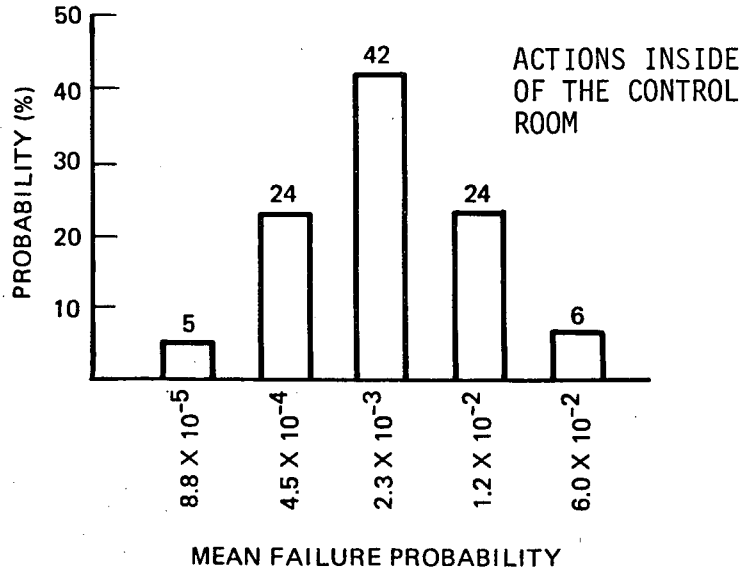
Pump maintenance consists of a range of actions from major disassembly to packing adjustment. Most maintenance on the AFWS pumps requires isolation of the pump from the system and, therefore, contributes to the maintenance unavailability of the pump train.

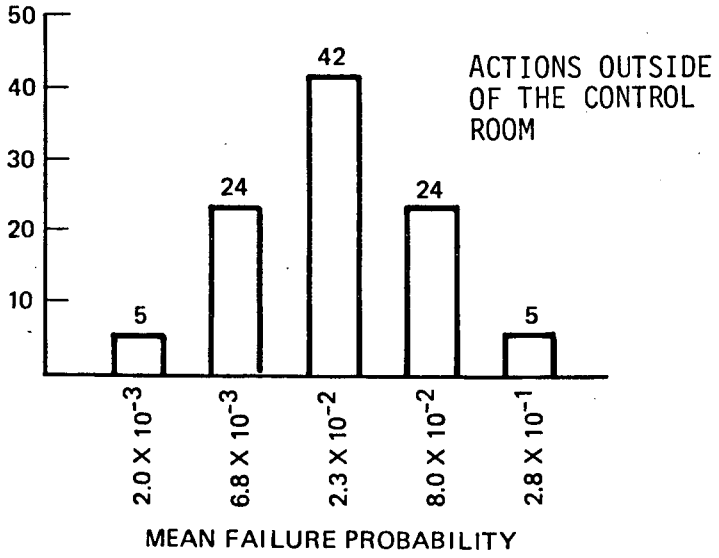
The maintenance on large motors ranges from inspection and cleaning to major disassembly. The prevalent failure mode is bearing failure which requires partial disassembly of the motor. All maintenance of the AFWS pump motors contributes to maintenance unavailability and is included in the pump train maintenance unavailability.

Turbine maintenance can range from simple adjustments to major disassembly. These outages are accounted for in the maintenance contribution to unavailability of the turbine-driven pump train. Table 1.5.2.3.9-9 gives the unavailability associated with maintenance on motor-driven and turbine pump trains. These figures are based on plant specific data.

1.5.2.3.9.4.4 Human Inaction. (See Tables 1.5.2.3.9-8G, 1.5.2.3.9-8H, and 1.5.2.3.9-8I). The probability of human inaction has been quantified into histograms based on discussions with operators, supervisory personnel, engineers, and after a review of the operating histories at other plants. The judgments take into account the high stress conditions in the control room during emergencies and the competing demands during the 30 minutes the operator has to perform his task.

The following histograms present the frequency distributions.





The means and variances of the previous histograms are presented in the following table.

Control Room Actions	With Existing Procedures	
	Mean	Variance
Actions in Control Room		
f (30 minutes)	0.007	$(0.02)^2$
Actions Outside Control Room		
f (30 minutes)	0.044	$(0.07)^2$

These failure frequency distributions are used to evaluate the probability that an operator takes correct action following a recoverable system failure.

A loss of the components that can be recovered by the operator is shown in the following:

- Turbine-Driven Auxiliary Feedwater Pump Trip. A major contributor to failure of turbine-driven AFWS pumps to start on demand is a failure of the turbine controls. This is primarily caused by turbine trip on overspeed during startup. The operator may manually reset the overspeed trip, or take control of the turbine-driven AFWS pump if it did not operate during demand. Based on experience and plant specific data for similar units, 50% of the failures to start are assumed recoverable within 30 minutes. The frequency of failure for the operator's not taking action within 30 minutes is f = 0.044 mean with 0.0049 variance.

- Failure of Either Condensate Storage Tank Outlet Valve. Failures in either condensate storage tank outlet valve are dominant contributors to failure for the cases analyzed. The city water storage tank is lined up with the AFWS and is a readily available source of water for the AFWS in case no water comes from the condensate storage tank. When the AFWS experiences low suction, the operator can switch over to these supplies by opening valves PCV-1187, 1188, and 1189. If the system air is out, the operator will still see low suction and can open these valves manually. Because the valves do not have hand cranks and need to be jacked open, this analysis conservatively assumes that there would not be enough time to open them.

1.5.2.3.9.4.5 Common Cause Analysis.

1.5.2.3.9.4.5.1 Common cause analysis. The method used to perform the common cause failure analysis is based on the system fault tree logic model. A search is made to identify those combinations of basic events that result in system failure, that is, the cutsets. In previous quantifications, each cutset was evaluated by considering each basic event as an independent "black box" with certain failure characteristics. Common cause differs in that it seeks to identify a failure characteristic in each of the basic events in a cutset pass. A simple example would be a cutset in which all the basic events are located in the same room and are susceptible to fire. Barriers between components, both physical and administrative, are considered in the analysis. The results of the common cause search are groups of cutsets identified by common failure characteristics and the absence of barriers.

1.5.2.3.9.4.5.2 Results of common cause analysis. A review of existing plant procedures indicated a potential for human error during monthly pump testing. During these tests, the manual gate valves, BFD-48-1, 3, 5, and 7 for the turbine-driven pump, and BFD-36, 38, 41, and 43 for the motor-driven pumps, are closed and the pumps are run in the recirculation mode for 20 to 30 minutes. At the completion of these tests, the pumps are secured and the manual gate valves are opened. The manual gate valves may erroneously not be reopened after the flow test. Tables 1.5.2.3.9-8J through 1.5.2.3.9-8K show the quantification of this common cause.

The AFWS components are in two general locations, the auxiliary pump room and the switchgear room. The following is a treatment of component susceptibilities to the environment:

- Conducting Medium. None present. Even if brought into the area, the equipment is protected.

- Impact. The AFWS is well protected against portable sources. No sources are present except for the turbine pump which, because of its placement and missile shield, poses no real threat to other AFWS components.

- Temperature. Fire is a possible risk and is analyzed in another section of this study. A turbine pump steam line break is also possible but the probability is small compared to other causes.

- Corrosion. There is no source of sufficient moisture. Further, regular maintenance is performed.

- Grit. Portable sources could be a problem, but equipment is well protected and heavy dirt is not generated during power operations.

- Vibration. Seismic problems are analyzed elsewhere in this study.

- Explosion. This is very unlikely; there are only portable sources and they are carefully controlled. Sufficient separation offers some protection.

A cutset containing all the same type of parts can have a common cause failure. If their is failure of the parts as a group, a system failure will occur. These components are tested regularly, but some problems may remain. For example, if a few similar parts show signs that they are wearing out, all parts of that type should be checked. However, there are situations in which tests do not accurately verify that a component is functioning properly. For example, the motor pump train is valved off and the pump is tested, but there is no flow test to ensure that the discharge valves are not plugged or otherwise obstructed. The environmental common causes and the similar parts common causes have not been explicity quantified in the AFWS section, but are considered to be in the range of 10^{-16} or less. This applies to those characteristics discussed previously and not analyzed in other sections. This range was based on the fact that these events are less likely than a pipe rupture, which has been quantified in the Reactor Safety Study as 10^{-10} failures/hour.

The common cause contribution is primarily due to a common human failure following testing--leaving all manual gate valves in the closed position. This is a recoverable failure and the unavailability contribution includes the 30-minute response time for operator intervention. Except for seismic contributions, which are evaluated in another section of this study, other common cause contributions were found to be negligible when compared to other derived values.

1.5.2.3.9.4.6 Other. The category "other," like parts of the common cause analysis, is not explicity quantified in the AFWS section for the same reasons. "Other" contributors to unavailability are less frequent than pipe rupture and, therefore, would have a value less than the pipe rupture failure rate. Because the pipe rupture number (1.0×10^{-10} failures/hour) is not a major contributor in the AFWS section, a smaller number would not be significant. Thus, the category "other" is defined as ε, which is less than 1.0×10^{-10} in the AFWS section.

1.5.2.3.9.5 Conclusions. The results presented in this section show that the Indian Point 2 AFWS is very reliable in the emergency mode. Redundancy, separation, availability during testing, and recoverability make the system sound. These results follow from the detailed fault tree in Figure 1.5.2.3.9-4, the data from Table 1.5.2.3.9-5, and the analysis described in Section 1.5.2.3.9.4. They are based on the failure of the AFWS to deliver at least 150 gpm to each of two steam generators. Approximately 30 minutes are available from the time of reactor trip until auxiliary feedwater is required based on normal steam generator water inventories. The dominant contributors to conditional unavailability are human error (inaction), test and maintenance, and nonrecoverable random failures.

A more detailed examination of the dominant contributors to unavailability is shown in Tables 1.5.2.3.9-11, 1.5.2.3.9-12, and 1.5.2.3.9-13. These tables display the dominant contributors, causes, and component failure modes for each case. For the "Full Power" case (Table 1.5.2.3.9-11), the dominant contributor is the water supply system followed by a human error related to the water system. The other major contributor is common cause associated with testing.

The "Loss of One Bus" case (Table 1.5.2.3.9-12) is dominated by three independent human errors related to the start of the turbine-driven pump and the opening of valves 405A, 405B, 405C, and 405D. There are also contributors from two test and maintenance failures and two nonrecoverable random failures.

The "No Power" case (Table 1.5.2.3.9-13) is different. In this case only the turbine train can be available, so single element cutsets in the turbine train are more important. Human error is the major contributor, followed by test and maintenance, and then nonrecoverable test and maintenance. This case shows that even with multiple failures that lead to a complete loss of all power, the AFWS should operate successfully. There is approximately a 1.4% chance of failure.

TABLE 1.5.2.3.9-1A

INDIAN POINT 2 AUXILIARY FEEDWATER SYSTEM UNAVAILABILITY TABLE FOR ALL CONTRIBUTORS

Contributor \ Power State	Full Power	Loss of One Bus	No Power
Mean Nonrecoverable Random Failures	A 1.03×10^{-5}	B 2.87×10^{-5}	C 2.07×10^{-3}
Mean Test and Maintenance	D 4.33×10^{-7}	E 4.57×10^{-5}	F 4.56×10^{-3}
Mean Independent Human Error	G 6.37×10^{-6}	H 8.48×10^{-5}	I 7.05×10^{-3}
Mean Common Cause	J 2.48×10^{-6}	K 2.48×10^{-6}	L 7.83×10^{-6}
Mean Others	ε	ε	ε
Mean Total	1.96×10^{-5}	1.62×10^{-4}	1.37×10^{-2}

X Calculated details are found in Table 1.5.2.3.9-8X (i.e., 1.5.2.3.9-8A through 1.5.2.3.9-8L).

TABLE 1.5.2.3.9-1B

INDIAN POINT 2 AUXILIARY FEEDWATER SYSTEM UNAVAILABILITY TABLE FOR THE DOMINANT CONTRIBUTORS

Statistical Category \ Power State	Full Power	Loss of One Bus	No Power
Table of Dominant Contributors for This Case	1.5.2.3.9-11	1.5.2.3.9-12	1.5.2.3.9-13
Approximate Percentage of Total Mean That Dominant Contributors Make Up	98	98	100
Mean	1.94×10^{-5}	1.59×10^{-4}	1.36×10^{-2}
Variance	4.72×10^{-10}	1.10×10^{-8}	1.67×10^{-4}
5th Percentile	2.75×10^{-6}	7.03×10^{-5}	3.88×10^{-3}
Median	1.06×10^{-5}	1.31×10^{-4}	9.69×10^{-3}
95th Percentile	4.67×10^{-5}	2.79×10^{-4}	3.55×10^{-2}

TABLE 1.5.2.3.9-2

INDIAN POINT 2 COMPONENT POWER SUPPLY SUMMARY

Component	Power Supply	Primary Source	Backup Source	Function
A. Steam Supply Train				
PCV-1139 (20-1/ABFP2)(1)	125 Volt DC Panel 22	Battery 22	Bus 2A	Steam Supply to Auxiliary Boiler Feed Pump 22 Turbine (Normally Closed)
PCV-1139 (20-2/ABFP2)(2)	125 Volt DC Panel 22	Battery 22	Bus 2A	Steam Supply to Auxiliary Boiler Feed Pump 22 Turbine (Normally Closed)
PCV-1310A (SOV-1310)(1)	125 Volt DC Panel 21	Battery 21	Bus 5A	Steam Supply Isolation Valve to Auxiliary BFP 22 Turbine (Normally Open)
PCV-1310B (SOV-1311)(1)	125 Volt DC Panel 22	Battery 22	Bus 2A	Steam Supply Isolation Valve to Auxiliary BFP 22 Turbine (Normally Open)
B. Turbine Pump 22 Train				
Auxiliary Boiler Feed Pump 22	Steam Driven	Residual Heat Generated Steam		
PCV-1188 (SOV-1288)(3)	120 Volt AC Distribution Panel 21	Bus 2A	Bus 6A	Valve on Alternate Path from City Water System for Auxiliary Feedwater Pump 22 Suction (Normally Closed)
FCV-405A(1)	120 Volt AC Vital Instrument Bus 21	Battery 21	Bus 5A	Auxiliary Boiler Feed Pump 22 Discharge to Steam Generator 21 (Normally Closed)
FCV-405B(1)	120 Volt AC Vital Instrument Bus 22	Battery 22	Bus 2A	Auxiliary Boiler Feed Pump 22 Discharge to Steam Generator 22 (Normally Closed)
FCV-405C(1)	120 Volt AC Vital Instrument Bus 23	Battery 23	Bus 3A	Auxiliary Boiler Feed Pump 22 Discharge to Steam Generator 23(Normally Closed)
FCV-405D(1)	120 Volt AC Vital Instrument Bus 24	Battery 24	Bus 6A	Auxiliary Boiler Feed Pump 22 Discharge to Steam Generator 24(Normally Closed)
C. Motor-Driven Pump 21 Train				
Auxiliary Boiler Feed Pump 21	480 Volt Bus 3A	Unit Auxiliary Transformer	Diesel 22	--
PCV-1187 (SOV-1287)(3)	120 Volt AC Distribution Panel 21	Bus 2A	Bus 6A	Valve on Alternate Path from City Water System for Auxiliary Feed Pump 21 Suction (Normally Closed)
FCV-406A(1)	120 Volt AC Vital Instrument Bus 23	Battery 23	Bus 3A	Auxiliary Boiler Feed Pump 21 Discharge to Steam Generator 21 (Normally Open)
FCV-406B(1)	120 Volt AC Vital Instrument Bus 23	Battery 23	Bus 3A	Auxiliary Boiler Feed Pump 21 Discharge to Steam Generator 22 (Normally Open)

(1) Valve Fails Open on Loss of Air or Electric Power
(2) Valve Fails Open on Loss of Air and Cannot be Closed Without Electric Power
(3) Valve Fails Closed on Loss of Air or Electric Power
(4) Redundant Position Switch/CCR Indication and Alarm

TABLE 1.5.2.3.9-2 (continued)

INDIAN POINT 2 COMPONENT POWER SUPPLY SUMMARY

Component	Power Supply	Primary Source	Backup Source	Function
D. Motor-Driven Pump 23 Train				
Auxiliary Boiler Feed Pump 23	480 Volt Bus 6A	Station Auxiliary Transformer	Diesel 23	--
PCV-1189 (SOV-1289)(3)	120 Volt AC Distribution Panel 21	Bus 2A	Bus 6A	Valve on Alternate Path from City Water System for Auxiliary Feed Pump 23 Suction (Normally Closed)
FCV-406C(1)	120 Volt AC Vital Instrument Bus 24	Battery 24	Bus 6A	Auxiliary Boiler Feed Pump 23 Discharge to Steam Generator 23 (Normally Open)
FCV-406D(1)	120 Volt AC Vital Instrument Bus 24	Battery 24	Bus 6A	Auxiliary Boiler Feed Pump 23 Discharge to Steam Generator 24 (Normally Open)
E. Miscellaneous				
LCV-1158 (SOV-1258)(3)	125 Volt DC Panel 21	Battery 21	Bus 5A	Condensate Storage Tank Low-Level Shutoff Valve (Normally Open)
CT-6(4)	Hand Operated	--		Condensate Storage Tank Discharge Valve (Locked Open)
CT-64(4)	Hand Operated	--		Condensate Storage Tank Discharge Valve (Locked Open)

(1)Valve Fails Open on Loss of Air or Electric Power
(2)Valve Fails Open on Loss of Air and Cannot be Closed Without Electric Power
(3)Valve Fails Closed on Loss of Air or Electric Power
(4)Redundant Position Switch/CCR Indication and Alarm

TABLE 1.5.2.3.9-3

INDIAN POINT 2 PIPING ANALYSIS

Pipe Section	Diameter (inches)	System Failure	Potential for Other System Impact	Initiating Event	Comments
Condensate Storage Tank Supply Line	12	No	None	No	Almost entire section can be isolated.
City Water Storage Tank Supply Line (before CT-49)	16	No	None	No	Almost entire section can be isolated.
City Water (after CT-49)	8	No	None	No	Almost entire section can be isolated.
Auxiliary Feed Line Downstream of BFD-79-3 to Steam Generator 23	4/18 AFWS/MF	No	Yes - Main Feed	Feed Line Break	Not isolated from steam generator downstream of the feedwater isolation valves.
Auxiliary Feed Line Downstream of BFD-79-3 to Steam Generator 24	4/18 AFWS/MF	No	Yes - Main Feed	Feed Line Break	Not isolated from steam generator downstream of the feedwater isolation valves.
Auxiliary Feed Line Downstream of BFD-79-3 to Steam Generator 22	4/18 AFWS/MF	No	Yes - Main Feed	Feed Line Break	Not isolated from steam generator downstream of the feedwater isolation valves.
Auxiliary Feed Line Downstream of BFD-79-3 to Steam Generator 21	4/18 AFWS/MF	No	Yes - Main Feed	Feed Line Break	Not isolated from steam generator downstream of the feedwater isolation valves.
Main Steam to AFWS Turbine Upstream of MS-41	4	No	Yes - Main Steam	Steam Line Break	No isolation but only a 4-inch break.
Main Steam to AFWS Turbine Upstream of MS-42	4	No	Yes - Main Steam	Steam Line Break	No isolation but only a 4-inch break.
Main Steam to AFWS Turbine Downstream of MS-41 and MS-42	4	No	Yes - Main Steam	Steam Line Break	No isolation but only a 4-inch break.

TABLE 1.5.2.3.9-4

INDIAN POINT 2 AFWS TESTING FREQUENCY

Component	Component (basic event)	Scheduled Testing (procedure)	Indirect Testing	Effective Test Schedule
JBSAC3AS	Electric train with AC bus 3A	None	Always energized	Constant monitoring
JBSAC6AS	Electric train with AC bus 6A	None	Always energized	Constant monitoring
4BSDC3AS	DC control power to bus 3A	None	Always energized	Constant monitoring
4BSDC6AS	DC control power to bus 6A	None	Always energized	Constant monitoring
NOAIR00S	Instrument air system	None	Always energized	Constant monitoring
PAV405AQ	Air-operated flow control valve FCV-405A	(3)*, (4)		18 months
PAV405BQ	Air-operated flow control valve FCV-405B	(3)*, (4)		18 months
PAV405CQ	Air-operated flow control valve FCV-405C	(3)*, (4)		18 months
PAV405DQ	Air-operated flow control valve FCV-405D	(3)*, (4)		18 months
PAV1139Q	Main steam air-operated valve PCV-1139	(2), (3),*(4)		Monthly
PAV1158X	CST low level shutoff valve LCV-1158	(3)		Quarterly
PAV1187Q	Air-operated shutoff valve PCV-1187	(3)*		Never
PAV1187Q	Air-operated shutoff valve PCV-1188	(3)*		Never
PAV1187Q	Air-operated shutoff valve PCV-1189	(3)*		Never
PAV406AG	Air-operated flow control valve FCV-406A	(3)*	(7), (8)	1,096 hours
PAV406BG	Air-operated flow control valve FCV-406B	(3)*	(7), (8)	1,096 hours
PAV406CG	Air-operated flow control valve FCV-406C	(3)*	(7), (8)	1,096 hours
PAV406DG	Air-operated flow control valve FCV-406D	(3)*	(7), (8)	1,096 hours
PAV310AG	Air-operated automatic high temperature shutoff valve PCV-1310A		(2), (4)	Monthly
PAV310BG	Air-operated automatic high temperature shutoff valve PCV-1310B		(2), (4)	Monthly

*Valves are stroked but there is no flow verification
**The monthly test PT-M37 proves only that one of the check valves, MS-41 or MS-42, worked properly
***Verifies only that it has not improperly closed valves under test conditions - assumed to be every 18 months

(1) Monthly (PT-M23)
(2) Monthly (PT-M37)
(3) Quarterly (PT-Q13)
(4) Refueling (PT-R22) - assumed every 18 months
(5) Variable (PT-V6)
(6) Variable (PT-V8)
(7) Refueling (PT-R7 - assumed every 18 months)
(8) Trips (based on unit experience 8 times per year)
(9) Weekly (PT-W4)

TABLE 1.5.2.3.9-4 (continued)

INDIAN POINT 2 AFWS TESTING FREQUENCY

Component	Component (basic event)	Scheduled Testing (procedure)	Indirect Testing	Effective Test Schedule
6CV0001X	Check valve on main feed supply line 1		(7), (8)	1,096 hours
6CV0002X	Check valve on main feed supply line 2		(7), (8)	1,096 hours
6CV0003X	Check valve on main feed supply line 3		(7), (8)	1,096 hours
6CV0004X	Check valve on main feed supply line 4		(7), (8)	1,096 hours
PCV0S41Q	Check valve MS-41**		(2)**	Monthly-never**
PCV0S42Q	Check valve MS-42**		(2)**	Monthly-never**
PCV0C25Q	Check valve CT-25			Never
PCV0C26Q	Check valve CT-26		(1), (7), (8)	438 hours
PCV0C28Q	Check valve CT-28			Never
PCV0029Q	Check valve CT-29		(2), (4)	Monthly
PCV0C31Q	Check valve CT-31			Never
PCV0031Q	Check valve BFD-31		(4)	18 months
PCV0032Q	Check valve CT-32		(1), (7), (8)	438 hours
PCV0034Q	Check valve BFD-34		(7), (8)	1,096 hours
PCV0035Q	Check valve BFD-35		(7), (8)	1,096 hours
PCV0037Q	Check valve BFD-37		(7), (8)	1,096 hours
PCV0039Q	Check valve BFD-39		(7), (8)	1,096 hours
PCV0040Q	Check valve BFD-40		(7), (8)	1,096 hours
PCV0042Q	Check valve BFD-42		(7), (8)	1,096 hours
PCV0470Q	Check valve BFD-47-0		(4)	18 months
PCV0471Q	Check valve BFD-47-1		(4)	18 months
PCV0472Q	Check valve BFD-47-2		(4)	18 months
PCV0473Q	Check valve BFD-47-3		(4)	18 months
PCV0790Q	Check valve BFD-79-0		(4), (7), (8)	1,096 hours
PCV0791Q	Check valve BFD-79-1		(4), (7), (8)	1,096 hours
PCV0792Q	Check valve BFD-79-2		(4), (7), (8)	1,096 hours
PCV0793Q	Check valve BFD-79-3		(4), (7), (8)	1,096 hours
JCXDP21S	AC distribution panel 21	None	Always energized	Constantly monitoring
PCXOP3AS	Valve controller on valve PCV-1310A		(2)***, (4)***	Monthly

*Valves are stroked but there is no flow verification
**The monthly test PT-M37 proves only that one of the check valves, MS-41 or MS-42, worked properly
***Verifies only that it has not improperly closed valves under test conditions - assumed to be every 18 months

(1) Monthly (PT-M23)
(2) Monthly (PT-M37)
(3) Quarterly (PT-Q13)
(4) Refueling (PT-R22) - assumed every 18 months
(5) Variable (PT-V6)
(6) Variable (PT-V8)
(7) Refueling (PT-R7 - assumed every 18 months)
(8) Trips (based on unit experience, 8 times per year)
(9) Weekly (PT-W4)

TABLE 1.5.2.3.9-4 (continued)

INDIAN POINT 2 AFWS TESTING FREQUENCY

Component	Component (basic event)	Scheduled Testing (procedure)	Indirect Testing	Effective Test Schedule
PCXOP3BS	Valve controller on valve PCV-1310B		(2)***, (4)***	Monthly
PCXSR3AS	Temperature sensor circuitry on valve PCV-1310A		(2)***, (4)***	Monthly
PCXSR3BS	Temperature sensor circuitry on valve PCV-1310B		(2)***, (4)***	Monthly
PCX1187S	Signal to open PCV-1187	(3)*		Never
PCX1188S	Signal to open PCV-1188	(3)*		Never
PCX1189S	Signal to open PCV-1189	(3)*		Never
PMD0021S	Motor operator to AFW pump 21	(1), (7)	(8)	Monthly
PMD0023S	Motor operator to AFW pump 23	(1), (7)	(8)	Monthly
PPM0021N	AFW motor pump 21	(1), (7)	(8)	Monthly
PPM0022N	AFW turbine pump 22	(2), (4)		Monthly
PPM0023N	AFW motor pump 23	(1), (7)	(8)	Monthly
6SG220FS	Steam generator 22		Always working	Constantly monitored
6SG230FS	Steam generator 23		Always working	Constantly monitored
PTB0022S	Turbine control for AFW pump 22	(2), (5), (6)		Monthly
PTKCITYS	City water supply tank	(9)		Weekly
PTKOCSTS	Condensate storage tank	(1), (2), (4), (7)	(8)	Constantly monitored
PXV0006G	Manual isolation butterfly valve CT-6	(1), (2), (4), (7)	(8)	438 hours
PXV0027G	Manual isolation gate valve CT-27	(1), (7)	(8)	438 hours
PXV0030G	Manual isolation gate valve CT-30	(2), (4)		Monthly
PXV0033G	Manual isolation gate valve CT-33	(1), (7)	(8)	438 hours
PXV0036G	Manual isolation gate valve BFD-36	(1)*	(7), (8)	1,096 hours
PXV0038G	Manual isolation gate valve BFD-38	(1)*	(7), (8)	1,096 hours
PXV0041G	Manual isolation gate valve BFD-41	(1)*	(7), (8)	1,096 hours
PXV0043G	Manual isolation gate valve BFD-43	(1)*	(7), (8)	1,096 hours
PXV0049G	Manual isolation gate valve CT-49			Never
PXV0054G	Manual isolation gate valve MS-54		(2)	Monthly

*Valves are stroked but there is no flow verification
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(1)Monthly (PT-M23)
(2)Monthly (PT-M37)
(3)Quarterly (PT-Q13)
(4)Refueling (PT-R22) - assumed every 18 months
(5)Variable (PT-V6)
(6)Variable (PT-V8)
(7)Refueling (PT-R7 - assumed every 18 months)
(8)Trips (based on unit experience, 8 times per year)
(9)Weekly (PT-W4)

TABLE 1.5.2.3.9-4 (continued)

INDIAN POINT 2 AFWS TESTING FREQUENCY

Component	Component (basic event)	Scheduled Testing (procedure)	Indirect Testing	Effective Test Schedule
PXV0064G	Manual isolation gate valve CT-64	(4), (7)	(8)	438 hours
PXV0480G	Manual isolation gate valve BFD-48-0		(4)	18 months
PXV0481G	Manual isolation gate valve BFD-48-1	(2)*	(4)	18 months
PXV0482G	Manual isolation gate valve BFD-48-2		(4)	18 months
PXV0483G	Manual isolation gate valve BFD-48-3	(2)*	(4)	18 months
PXV0484G	Manual isolation gate valve BFD-48-4		(4)	18 months
PXV0485G	Manual isolation gate valve BFD-48-5	(2)*	(4)	18 months
PXV0486G	Manual isolation gate valve BFD-48-6		(4)	18 months
PXV0487G	Manual isolation gate valve BFD-48-7	(2)*	(4)	18 months
PXV0620G	Manual isolation gate valve BFD-62-0		(7), (8)	1,096 hours
PXV0621G	Manual isolation gate valve BFD-62-1		(7), (8)	1,096 hours
PXV0622G	Manual isolation gate valve BFD-62-2		(7), (8)	1,096 hours
PXV0623G	Manual isolation gate valve BFD-62-3		(7), (8)	1,096 hours

*Valves are stroked but there is no flow verification
**The monthly test PT-M37 proves only that one of the check valves, MS-41 or MS-42, worked properly
***Verifies only that it has not improperly closed valves under test conditions - assumed to be every 18 months

(1) Monthly (PT-M23)
(2) Monthly (PT-M37)
(3) Quarterly (PT-Q13)
(4) Refueling (PT-R22) - assumed every 18 months
(5) Variable (PT-V6)
(6) Variable (PT-V8)
(7) Refueling (PT-R7 - assumed every 18 months)
(8) Trips (based on unit experience, 8 times per year)
(9) Weekly (PT-W4)

TABLE 1.5.2.3.9-5

INDIAN POINT 2 AFWS BASIC EVENTS

Reference (1)	Component	Component (basic event)	Failure Mode	Unavailability or Failures/Demand	
				Mean	Variance
	JBSAC3AS	Electric train with AC bus 3A	Loss of function	Assumed on or off	
	JBSAC6AS	Electric train with AC bus 6A	Loss of function	Assumed on or off	
	4BSDC3AS	DC control power to bus 3A	Loss of function	Assumed on or off	
	4BSDC6AS	DC control power to bus 6A	Loss of function	Assumed on or off	
	NOAIR00S	Instrument air system	Loss of function	Assumed to be off	
8	PAV405AQ	Air-operated flow control valve FCV-405A	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
8	PAV405BQ	Air-operated flow control valve FCV-405B	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
8	PAV405CQ	Air-operated flow control valve FCV-405C	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
8	PAV405DQ	Air-operated flow control valve FCV-405D	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
8	PAV1139Q	Main steam air-operated valve PCV-1139	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
8	PAV1158X	CST low level shutoff valve LCV-1158	Component open and does not close	7.49×10^{-4}	4.01×10^{-7}
8	PAV1187Q	Air-operated shutoff valve PCV-1187	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
8	PAV1188Q	Air-operated shutoff valve PCV-1188	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
8	PAV1189Q	Air-operated shutoff valve PCV-1189	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
9	PAV406AG	Air-operated flow control valve FCV-406A	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
9	PAV406BG	Air-operated flow control valve FCV-406B	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
9	PAV406CG	Air-operated flow control valve FCV-406C	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
9	PAV406DG	Air-operated flow control valve FCV-406D	Failure to operate	7.49×10^{-4}	4.01×10^{-7}
9	PAV310AG	Air-operated automatic high temperature shutoff valve PCV-1310A	Plugged	6.24×10^{-5}	9.71×10^{-9}
9	PAV310BG	Air-operated automatic high temperature shutoff valve PCV-1310B	Plugged	6.24×10^{-5}	9.71×10^{-9}
4	6CV0001X	Check valve on main feed supply line 1	Component open and does not close	7.36×10^{-6}	6.59×10^{-11}
4	6CV0002X	Check valve on main feed supply line 2	Component open and does not close	7.36×10^{-6}	6.59×10^{-11}
4	6CV0003X	Check valve on main feed supply line 3	Component open and does not close	7.36×10^{6}	6.59×10^{-11}
4	6CV0004X	Check valve on main feed supply line 4	Component open and does not close	7.36×10^{-6}	6.59×10^{-11}
3	PCV0S41Q(2)	Check valve MS-41	Component closed and does not open	1.00	0.00
3	PCV0S42Q(2)	Check valve MS-42	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0C25Q	Check valve CT-25	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0C26Q	Check valve CT-26	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0C28Q	Check valve CT-28	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0029Q	Check valve CT-29	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0C31Q	Check valve CT-31	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0031Q	Check valve BFD-31	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0032Q	Check valve CT-32	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0034Q	Check valve BFD-34	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0035Q	Check valve BFD-35	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0037Q	Check valve BFD-37	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0039Q	Check valve BFD-39	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0040Q	Check valve BFD-40	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}

(1)See item number in Section 1.5.1-2 (Table 1.5.1-4, Data Tables). "D" indicates that the values for unavailability came from generic data, not plant specific data.
(2)These two valves are tested monthly, but you can only verify that one works. For this reason one valve has been defined.
(3)Time for AFWS to perform its limited function (Section 1.3.1)

TABLE 1.5.2.3.9-5 (continued)

INDIAN POINT 2 AFWS BASIC EVENTS

Reference (1)	Component	Component (basic event)	Failure Mode	Unavailability or Failures/Demand	
				Mean	Variance
3	PCV0042Q	Check valve BFD-42	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0470Q	Check valve BFD-47-0	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0471Q	Check valve BFD-47-1	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0472Q	Check valve BFD-47-2	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0473Q	Check valve BFD-47-3	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0790Q	Check valve BFD-79-0	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0791Q	Check valve BFD-79-1	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0792Q	Check valve BFD-79-2	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
3	PCV0793Q	Check valve BFD-79-3	Component closed and does not open	7.02×10^{-5}	1.09×10^{-8}
	JCXDP21S	AC distribution panel 21	Loss of function	Assumed as part of bus	
	PCXOP3AS	Valve controller on valve PCV-1310A	Loss of function	Included in PAV310AG	
	PCXOP3BS	Valve controller on valve PCV-1310B	Loss of function	Included in PAV310BG	
	PCXSR3AS	Temperature sensor circuitry on valve PCV-1310A	Loss of function	Included in PAV310AG	
	PCXSR3BS	Temperature sensor circuitry on valve PCV-1310B	Loss of function	Included in PAV310BG	
	PCX1187S	Signal to open PCV-1187	Loss of function	Included in PAV1187Q	
	PCX1188S	Signal to open PCV-1188	Loss of function	Included in PAV1188Q	
	PCX1189S	Signal to open PCV-1189	Loss of function	Included in PAV1189Q	
	PMD0021S	Motor operator to AFW pump 21	Loss of function	Included in PPM0021N	
	PMD0023S	Motor operator to AFW pump 23	Loss of function	Included in PPM0023N	
11, 20	PPM0021N	AFW motor pump 21	Does not start or operate	6.93×10^{-3}	8.45×10^{-6}
12, 21	PPM0022N	AFW turbine pump 22	Does not start or operate	1.10×10^{-3}	6.51×10^{-6}
11, 20	PPM0023N	AFW motor pump 23	Does not start or operate	6.93×10^{-3}	8.45×10^{-6}
(3)	6SG220FS	Steam generator 22	Loss of function	9.17×10^{-5}	1.77×10^{-8}
(3)	6SG230FS	Steam generator 23	Loss of function	9.17×10^{-5}	1.77×10^{-8}
	PTB0022S	Turbine control for AFW pump 22	Loss of function	Included in PPM0022N	
	PTKCITYS	City water supply tank	Loss of function	7.12×10^{-8}	3.60×10^{-13}
	PTKOCSTS	Condensate storage tank	Loss of function	1.86×10^{-7}	2.45×10^{-12}
1	PXV0006G	Manual isolation butterfly valve CT-6	Plugged	1.62×10^{-5}	2.82×10^{-10}
1	PXV0027G	Manual isolation gate valve CT-27	Plugged	1.62×10^{-5}	2.82×10^{-10}
1	PXV0030G	Manual isolation gate valve CT-30	Plugged	1.62×10^{-5}	2.82×10^{-10}
1	PXV0033G	Manual isolation gate valve CT-33	Plugged	1.62×10^{-5}	2.82×10^{-10}
1	PXV0036G	Manual isolation gate valve BFD-36	Plugged	4.06×10^{-5}	1.77×10^{-9}
1	PXV0038G	Manual isolation gate valve BFD-38	Plugged	4.06×10^{-5}	1.77×10^{-9}
1	PXV0041G	Manual isolation gate valve BFD-41	Plugged	4.06×10^{-5}	1.77×10^{-9}
1	PXV0043G	Manual isolation gate valve BFD-43	Plugged	4.06×10^{-5}	1.77×10^{-9}

(1) See item number in Section 1.5.1-2 (Table 1.5.1-4, Data Tables). "D" indicates that the values for unavailability came from generic data, not plant specific data.
(2) These two valves are tested monthly, but you can only verify that one works. For this reason one valve has been defined.
(3) Time for AFWS to perform its limited function (Section 1.3.1)

TABLE 1.5.2.3.9-5 (continued)

BASIC EVENTS FOR THE INDIAN POINT 2 AFWS

Reference (1)	Component	Component (basic event)	Failure Mode	Unavailability or Failures/Demand	
				Mean	Variance
1	PXV0049G	Manual isolation gate valve CT-49	Plugged	1.30×10^{-2}	1.80×10^{-4}
1	PXV0054G	Manual isolation gate valve MS-54	Plugged	2.70×10^{-5}	7.75×10^{-10}
1	PXV0064G	Manual isolation gate valve CT-64	Plugged	1.62×10^{-5}	2.82×10^{-10}
1	PXV0480G	Manual isolation gate valve BFD-48-0	Plugged	4.87×10^{-4}	2.55×10^{-7}
1	PXV0481G	Manual isolation gate valve BFD-48-1	Plugged	4.87×10^{-4}	2.55×10^{-7}
1	PXV0482G	Manual isolation gate valve BFD-48-2	Plugged	4.87×10^{-4}	2.55×10^{-7}
1	PXV0483G	Manual isolation gate valve BFD-48-3	Plugged	4.87×10^{-4}	2.55×10^{-7}
1	PXV0484G	Manual isolation gate valve BFD-48-4	Plugged	4.87×10^{-4}	2.55×10^{-7}
1	PXV0485G	Manual isolation gate valve BFD-48-5	Plugged	4.87×10^{-4}	2.55×10^{-7}
1	PXV0486G	Manual isolation gate valve BFD-48-6	Plugged	4.87×10^{-4}	2.55×10^{-7}
1	PXV0487G	Manual isolation gate valve BFD-48-7	Plugged	4.87×10^{-4}	2.55×10^{-7}
1	PXV0620G	Manual isolation gate valve PGD-62-0	Plugged	4.06×10^{-5}	1.77×10^{-9}
1	PXV0621G	Manual isolation gate valve PGD-62-1	Plugged	4.06×10^{-5}	1.77×10^{-9}
1	PXV0622G	Manual isolation gate valve PGD-62-2	Plugged	4.06×10^{-5}	1.77×10^{-9}
1	PXV0623G	Manual isolation gate valve PGD-62-3	Plugged	4.06×10^{-5}	1.77×10^{-9}

(1) See item number in Section 1.5.1-2 (Table 1.5.1-4, Data Tables). "D" indicates that the values for unavailability came from generic data, not plant specific data.
(2) These two valves are tested monthly, but you can only verify that one works. For this reason one valve has been defined.
(3) Time for AFWS to perform its limited function (Section 1.3.1).

TABLE 1.5.2.3.9-6

INDIAN POINT 2 SUPERCOMPONENT CUTSETS (UP TO THREE BASIC EVENTS)

There are no cutsets containing one basic event.

Cutsets with two basic events.

WW2	WW1

Cutsets with three basic events.

WP3-OP	WC2	WP2	WD2	WP3-OP	WP2	WD2	WD3	WD4
WP3-OP	WC1	WP2	WD1	WP3-OP	WP2	WD1	WD3	WD4
WP3-OP	WP1	WD4	WD3-OP	WP1	WC4	WD1	WD2	WD4
WP3-OP	WP1	WD3	WP3-OP	WP1	WP2	WP3-OP	WP1	WC3
WD1	WD2	WD3						

TABLE 1.5.2.3.9-7A

INDIAN POINT 2 SUPERCOMPONENT W1 (CST WATER SUPPLY) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PXV0006G	7.40×10^{-8}	5.89×10^{-15}	219(4)	1.62×10^{-5}	2.82×10^{-10}	1
2. PXV0064G	7.40×10^{-8}	5.89×10^{-15}	219(4)	1.62×10^{-5}	2.82×10^{-10}	1
3. PTKOCSTS	8.48×10^{-10}	5.10×10^{-17}	8(2)	6.78×10^{-9}	3.26×10^{-15}	44
4. PAV1158X(3)	--	--	--	7.49×10^{-4}	4.01×10^{-7}	8

NOTE: Supercomponent W1: mean = 7.81×10^{-4}; variance = 4.02×10^{-7}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).
(2) Time for AFWS to perform its limited function (Section 1.3.1).
(3) The failure of this value is assumed to fail the CST water supply. This is a conservative assumption because there are other means to preserve this water source for which no credit is being taken.
(4) MTTR is one-half the effective test schedule specified in Table 1.5.2.3.9-4.

SUPERCOMPONENT W1 LAYOUT

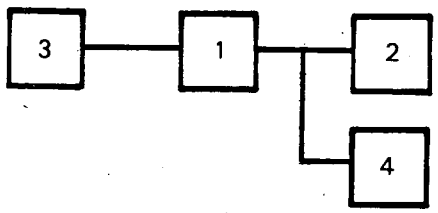


TABLE 1.5.2.3.9-7B

INDIAN POINT 2 SUPERCOMPONENT W2 (CITY WATER SUPPLY) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PXV0049G(2)	7.40×10^{-8}	5.89×10^{-15}	$1.75 \times 10^{+5}$(3)	1.30×10^{-2}	1.80×10^{-4}	1
2. PTKCITYS	8.48×10^{-10}	5.10×10^{-17}	84(3)	7.12×10^{-8}	3.60×10^{-13}	44

NOTE: Supercomponent W2: mean = 1.30×10^{-2}; variance = 1.80×10^{-4}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).
(2) Since the valves are never flow tested to be sure they are not plugged, the MTTR used was one-half of the plant lifetime of 40 years or $1.75 \times 10^{+5}$ hours.
(3) MTTR is one-half the effective test schedule specified in Table 1.5.2.3.9-4.

SUPERCOMPONENT W2 LAYOUT

TABLE 1.5.2.3.9-7C

INDIAN POINT 2 SUPERCOMPONENT R1, R2, OR R3 (CST WATER SUPPLY VALVES) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PCV0026Q (29Q, 32Q)	--	--	--	7.02×10^{-5}	1.09×10^{-8}	3
2. PXV0027G (30G, 33G)	7.40×10^{-8}	5.89×10^{-15}	219(2)	1.62×10^{-5}	2.82×10^{-10}	1

NOTE: Supercomponent R1, R2, or R3: mean = 9.64×10^{-5}; variance = 1.12×10^{-8}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).
(2) MTTR is one-half the effective test schedule specified in Table 1.5.2.3.9-4.

SUPERCOMPONENT R1, R2, R3 LAYOUT

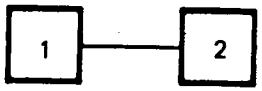


TABLE 1.5.2.3.9-7D

INDIAN POINT 2 SUPERCOMPONENT S1, S2, OR S3 (CITY WATER SUPPLY VALVES) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PCVOC25Q (29Q, 32Q)	--	--	--	7.02×10^{-5}	1.09×10^{-8}	3
2. PAV1187Q (1188Q, 1189Q)	--	--	--	7.49×10^{-4}	4.01×10^{-7}	8

NOTE: Supercomponent S1, S2, or S3: mean = 8.19×10^{-4}; variance = 4.12×10^{-7}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).

SUPERCOMPONENT S1, S2, S3 LAYOUT

TABLE 1.5.2.3.9-7E

INDIAN POINT 2 SUPERCOMPONENTS P1 AND P2 (MOTOR PUMP TRAIN 21, 23) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PPM0021N (23N)						
Fail to start	--	--	--	6.41×10^{-3}	7.78×10^{-6}	11
Fail to operate	6.54×10^{-5}	1.05×10^{-8}	8(2)	5.23×10^{-4}	6.72×10^{-7}	20
2. PCV0034Q (039Q)	--	--	--	7.02×10^{-5}	1.09×10^{-8}	3

NOTE: Supercomponents P1 and P2: mean = 7.00×10^{-3}; variance = 8.46×10^{-6}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).
(2) Time for AFWS to perform its limited function (Section 1.3.1).

SUPERCOMPONENT P1, P2 LAYOUT

TABLE 1.5.2.3.9-7F

INDIAN POINT 2 SUPERCOMPONENT P3 (TURBINE PUMP TRAIN 22) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PAV1139Q	--	--	--	7.49×10^{-4}	4.01×10^{-7}	8
2. PPM0022N						
Fail to start(3)	--	--	--	1.01×10^{-3}	6.25×10^{-6}	12
Fail to operate	1.15×10^{-5}	3.99×10^{-9}	8(2)	9.20×10^{-5}	2.55×10^{-7}	21
3. PCV0031Q	--	--	--	7.02×10^{-5}	1.09×10^{-8}	3
4. PCV0S41Q(5)	--	--	--	1.00	0.00	
5. PCV0S42Q(5)	--	--	--	7.02×10^{-5}	1.09×10^{-8}	3
6. PAV310AG	1.71×10^{-7}	7.29×10^{-14}	365(6)	6.24×10^{-5}	9.71×10^{-9}	9
7. PAV310BG	1.71×10^{-7}	7.29×10^{-14}	365(6)	6.24×10^{-5}	9.71×10^{-9}	9
8. PXV0054G	7.40×10^{-8}	5.89×10^{-15}	365(6)	2.70×10^{-5}	7.85×10^{-10}	1
9. GSG220FS	3.82×10^{-6}	3.08×10^{-11}	24(6)	9.17×10^{-5}	1.77×10^{-8}	(4)
10. GSG230FS	3.82×10^{-6}	3.08×10^{-11}	24(6)	9.17×10^{-5}	1.77×10^{-8}	(4)

NOTE: Supercomponent P3: mean = 2.07×10^{-3}; variance = 3.37×10^{-6}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).
(2) Time for AFWS to perform its limited function (Section 1.3.1).
(3) Based on experience and plant specific data for similar units, 50% of the failure to start are assumed recoverable within 30 minutes (mean 2.01×10^{-3} to 1.01×10^{-3}, variance 2.50×10^{-5} to 6.25×10^{-6}).
(4) Steam generator failure is dominated by a tube rupture failure of 2.74×10^{-2}/year and a variance of $2.3.1 \times 10^{-3}$. The reference for this is the initiating event occurrence probability Table 1.5.1-34. This number has been converted to 3.82×10^{-6}/hour and a variance of 3.08×10^{-11}. The mean time to repair is taken to be one-half of 48 hours. This is based on the isolation of the steam generator and shutdown times. Although the actual mean time to repair is generally greater than 48 hours, after this time the system will be shut down with no need for the auxiliary feedwater system.
(5) These two valves are tested monthly, but you can only verify that one works. For this reason one valve has been defined as failed.
(6) MTTR is one-half the effective test schedule specified in Table 1.5.2.3.9-4.

SUPERCOMPONENT P3 LAYOUT

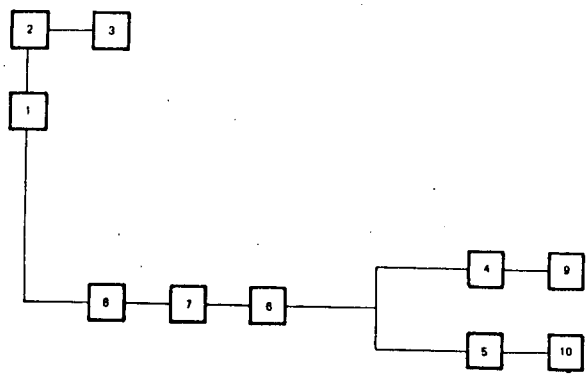


TABLE 1.5.2.3.9-7G

INDIAN POINT 2 SUPERCOMPONENT C1, C2, C3, OR C4
(MOTOR-DRIVEN PUMP DISCHARGE VALVES) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PXV0620G (621, 622, 623)	7.40×10^{-8}	5.89×10^{-15}	548(2)	4.06×10^{-5}	1.77×10^{-9}	1
2. PAV406AG (406B, C, D)	--	--	--	7.49×10^{-4}	4.01×10^{-7}	8
3. PCV0037Q (35, 40, 42)	--	--	--	7.02×10^{-5}	1.09×10^{-8}	3
4. PXV0038G (36, 41, 43)	7.40×10^{-8}	5.89×10^{-15}	548(2)	4.06×10^{-5}	1.77×10^{-9}	1

NOTE: Supercomponent C1, C2, C3, or C4: mean = 9.00×10^{-4}; variance = 4.15×10^{-7}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).
(2) MTTR is one-half the effective test schedule specified in Table 1.5.2.3.9-4.

SUPERCOMPONENT C1, C2, C3, C4 LAYOUT

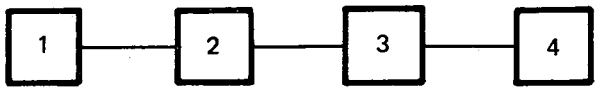


TABLE 1.5.2.3.9-7H

INDIAN POINT 2 SUPERCOMPONENT E1, E2, E3, OR E4
(TURBINE-DRIVEN PUMP DISCHARGE VALVES) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PXV0480G (482, 484, 486)	7.40×10^{-8}	5.89×10^{-15}	6,575(2)	4.87×10^{-4}	2.55×10^{-7}	1
2. PAV405AQ (405B, C, D)	--	--	--	7.49×10^{-4}	4.01×10^{-7}	8
3. PCV0470Q (471, 472, 473)	--	--	--	7.02×10^{-5}	1.09×10^{-8}	3
4. PXV0481G (483, 485, 487)	7.40×10^{-8}	5.89×10^{-15}	6,575(2)	4.87×10^{-4}	2.55×10^{-7}	1

NOTE: Supercomponent E1, E2, E3, or E4: mean = 1.79×10^{-3}; variance = 1.17×10^{-6}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).
(2) MTTR is one-half the effective test schedule specified in Table 1.5.2.3.9-4.

SUPERCOMPONENT E1, E2, E3, E4 LAYOUT

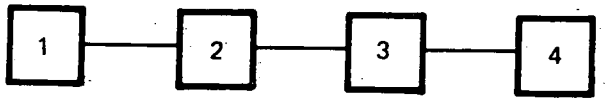


TABLE 1.5.2.3.9-7I

INDIAN POINT 2 SUPERCOMPONENT D1, D2, D3, OR D4
(STEAM GENERATOR SUPPLY VALVES) MEAN AND VARIANCE

Component (Table 1.5.2.3.9-5)	Fail/Hour	Variance	MTTR (hours)	Mean Unavailability	Variance	Reference(1)
1. PCV0790Q (791,792,793)	--	--	--	7.02×10^{-5}	1.09×10^{-8}	3
2. 6CV0001X (2, 4, 3)	9.20×10^{-7}	1.03×10^{-12}	8(2)	7.36×10^{-6}	6.59×10^{-11}	4

NOTE: Supercomponent D1, D2, D3, D4: mean = 7.76×10^{-5}; variance = 1.10×10^{-8}.

(1) See item number in Section 1.5.1.2 (Table 1.5.1-4, Data Tables).
(2) Time for AFWS to perform its limited function (Section 1.3.1).

SUPERCOMPONENT D1, D2, D3, D4 LAYOUT

TABLE 1.5.2.3.9-8A

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR NONRECOVERABLE RANDOM FAILURES WITH FULL ELECTRICAL POWER

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Failure of the CST water supply, W1 (Table 1.5.2.3.9-7A) and failure of the city water supply, W2 (Table 1.5.2.3.9-7B)	1.02×10^{-5}	98.5
2. Failure of all three pumps P1, P2, and P3 (Table 1.5.2.3.9-7E and Table 1.5.2.3.9-7F)	1.03×10^{-7}	1.0
3. Failure of the turbine-driven pump, P3 (Table 1.5.2.3.9-7F), failure of either motor-driven pump, P1 or P2 (Table 1.5.2.3.9-7E), and discharge valve train on the failure of either motor pump other motor-driven pump, C1, C2, C3, or C4 (Table 1.5.2.3.9-7G)	5.15×10^{-8}	0.5
TOTAL	1.03×10^{-5}	100.0

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8B

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR NONRECOVERABLE RANDOM FAILURES WITH ONE BUS UNAVAILABLE

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Failure of the turbine-driven pump train, P3 (Table 1.5.2.3.9-7F) and failure of the motor-driven pump train that still has electric power, P1 or P2 (Table 1.5.2.3.9-7E)	1.45×10^{-5}	50.4
2. Failure of the CST water supply, W1 (Table 1.5.2.3.9-7A) and failure of the city water supply, W2 (Table 1.5.2.3.9-7B)	1.02×10^{-5}	35.4
3. Failure of the turbine-driven pump train, P3 (Table 1.5.2.3.9-7F) and failure of a motor-driven pump discharge valve train on the functioning pump, C1, C2, C3, or C4 (Table 1.5.2.3.9-7G)	3.73×10^{-6}	13.0
TOTAL	2.87×10^{-5}	100.0

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8C

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR NONRECOVERABLE RANDOM FAILURES WITH NO ELECTRICAL POWER

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Failure of the turbine-driven pump train, P3 (Table 1.5.2.3.9-7F)	2.07×10^{-3}	99.4
TOTAL	2.08×10^{-3}	100.0

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8D

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR TEST AND MAINTENANCE (AND NONRECOVERABLE RANDOM FAILURE) WITH FULL ELECTRICAL POWER

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Turbine-driven pump maintenance (Table 1.5.2.3.9-9) coupled with failure of both motor-driven pumps, P1 and P2 (Table 1.5.2.3.9-7E)	2.24×10^{-7}	46.8
2. Turbine-driven pump maintenance (Table 1.5.2.3.9-9) coupled with failure of one motor-driven pump train, P1 or P2 (Table 1.5.2.3.9-7E) and a motor-driven pump discharge valve train failure in the other motor pump train, C1, C2, C3, or C4 (Table 1.5.2.3.9-7G)	1.15×10^{-7}	24.0
3. Motor-driven pump maintenance (Table 1.5.2.3.9-9) coupled with failures of the other two pump trains, P1 or P2, and P3 (Tables 1.5.2.3.9-7E and 7F)	6.55×10^{-8}	13.7
4. Motor-driven pump maintenance (Table 1.5.2.3.9-9) coupled with failure of the turbine-driven pump train P3 (Table 1.5.2.3.9-7F) and failure of a motor-driven pump discharge valve train of the functioning pump, C1, C2, C3, or C4 (Table 1.5.2.3.9-7G)	1.69×10^{-8}	3.5
TOTAL	4.33×10^{-7}	100.0

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8E

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR TEST AND MAINTENANCE (AND NONRECOVERABLE RANDOM FAILURE) WITH ONE BUS AVAILABLE

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Turbine-driven pump maintenance (Table 1.5.2.3.9-9) coupled with a failure of the remaining motor-driven pump, P1 (Table 1.5.2.3.9-7E)	3.19×10^{-5}	69.8
2. Turbine-driven pump maintenance (Table 1.5.2.3.9-9) coupled with a failure of either motor-driven pump discharge valve train C1, C2, C3, or C4 (Table 1.5.2.3.9-7E) associated with the motor-driven pump having power	8.22×10^{-6}	18.0
3. Motor-driven pump maintenance (Table 1.5.2.3.9-9) coupled with a failure of the turbine-driven pump train, P3 (Table 1.5.2.3.9-7F)	4.67×10^{-6}	10.2
TOTAL	4.57×10^{-5}	100.0

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8F

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR TEST AND MAINTENANCE (AND NONRECOVERABLE RANDOM FAILURE) WITH NO ELECTRICAL POWER

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Turbine-driven pump maintenance (Table 1.5.2.3.9-9)	4.56×10^{-3}	100.0
TOTAL	4.56×10^{-3}	100.0

*See Tables 1.5.2.3.9-1A and 1B

TABLE 1.5.2.3.9-8G

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR INDEPENDENT HUMAN ERROR (TEST AND MAINTENANCE AND NONRECOVERABLE RANDOM FAILURES) WITH FULL ELECTRICAL POWER

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Operator failure (Section 1.5.2.3.9.4.3) to open the city water valves coupled with a failure of the CST water supply, W1 (Table 1.5.2.3.9-7A)	5.47×10^{-6}	85.9
2. Operator failure (Section 1.5.2.3.9.4.3)to start the turbine-driven pump and open valves 405A, B, C, and D, plus a failure of the two motor-driven pumps, P1, P2 (Table 1.5.2.3.9-7E)	3.43×10^{-7}	5.4
3. Operator failure (Section 1.5.2.3.9.4.3) to start the turbine-driven pump and open valves 405A, B, C, and D; maintenance on one and failure of the other motor-driven pump	2.22×10^{-7}	3.5
4. Operator failure (Section 1.5.2.3.9.4.3) to start the turbine-driven pump and open valves 405A, B, C, and D; failure of one motor-driven pump train, P1, P2 (Table 1.5.2.3.9-7E) and a failure of either discharge valve train, C1, C2, C3, or C4 (Table 1.5.2.3.9-7G) of the remaining motor-driven pump	1.76×10^{-7}	2.8
TOTAL	6.37×10^{-6}	100.0

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8H

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR INDEPENDENT HUMAN ERROR (TEST AND MAINTENANCE, AND NONRECOVERABLE RANDOM FAILURES) WITH ONE BUS AVAILABLE

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Operator failure (Section 1.5.2.3.9.4.3) to start the turbine-driven pump and open valves 405A, B, C, and D coupled with a failure of the remaining motor-driven pump	4.90×10^{-5}	57.8
2. Operator failure (Section 1.5.2.3.9.4.3) to start the turbine-driven pump and open valves 405A, B, C, and D coupled with maintenance on the remaining motor-driven pump (Table 1.5.2.3.9-9)	1.60×10^{-5}	18.9
3. Operator failure (Section 1.5.2.3.9.4.3) to start the turbine-driven pump and open valves 405A, B, C, and D coupled with a loss of either motor-driven pump discharge valve train associated with the remaining pump, C1, C2, C3, or C4 (Table 1.5.2.3.9-7G)	1.26×10^{-5}	14.9
4. Operator failure (Section 1.5.2.3.9.4.3) to open the city water valves, S1, S2, or S3 (Table 1.5.2.3.9-7D) coupled with CST water supply failure	5.47×10^{-6}	6.5
TOTAL	8.48×10^{-5}	100.0

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8I

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR INDEPENDENT HUMAN ERROR (TEST AND MAINTENACE, AND NONRECOVERABLE RANDOM FAILURES) WITH NO ELECTRICAL POWER

RAS Developed Dominant Cutsets		
Cutset	Unavailability	Approximate Contribution (percent)
1. Failure of the operator (Section 1.5.2.3.9.4.3) to start the motor-driven pump and valves 405A, B, C, and D	7.00×10^{-3}	99.3
TOTAL	7.05×10^{-3}	100.0

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8J

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS
UNAVAILABILITY TABLE* FOR COMMON CAUSE/HUMAN ERROR
WITH FULL ELECTRICAL POWER

Failure to restore gate valves following AFW pump tests (e.g., BFD-36, 38, 41, 43, 48-1, 48-3, 48-5, and 48-7) together with failure of independent verification to note failure and correct, along with the operator failure to correct the valves during a need for the AFS is:

$$(5.64 \times 10^{-5})(0.044) = 2.48 \times 10^{-6}$$

where 5.64×10^{-5}, which is taken from the error rates section, is the probability of closing all of the valves and not reopening them as well as failure of an independent checker to notice the valves in an incorrect position and 0.044 is the probability that the operator does not notice the problem and correct it.

There are other permutations of common cause which include combinations of random failures, maintenance outages, and states of the electric power system. However, the resulting system unavailability contribution from this is at least two orders of magnitude less than any contributor already calculated.

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8K

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR COMMON CAUSE/HUMAN ERROR WITH ONE BUS AVAILABLE

Failure to restore gate valves following AFW pump tests (e.g., BFD-36, 38, 41, 43, 48-1, 48-3, 48-5, and 48-7) together with failure of independent verification to note failure and correct, along with the operator failure to correct the valves during a need for the AFS is:

$$(5.64 \times 10^{-5})(0.044) = 2.48 \times 10^{-6}$$

where 5.64×10^{-5}, which is taken from the error rates section, is the probability of closing all of the valves and not reopening them as well as failure of an independent checker to notice the valves in an incorrect position and 0.044 is the probability that the operator does not notice the problem and correct it.

There are other permutations of common cause which include combinations of random failures, maintenance outages, and states of the electric power system. However, the resulting system unavailability contribution from this is at least two orders of magnitude less than any contributor already calculated.

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-8L

INDIAN POINT 2 DEVELOPMENT OF ENTRIES TO AFS UNAVAILABILITY TABLE* FOR COMMON CAUSE/HUMAN ERROR WITH NO ELECTRICAL POWER

Failure to restore gate valves following AFW pump test (e.g., BFD-48-1, 48-3, 48-5, and 48-7) together with failure of independent verification to note failure and correct, along with the operator failure to correct the valves during a need for the AFS is:

$$(1.78 \times 10^{-4})(0.044) = 7.83 \times 10^{-6}$$

where 1.78×10^{-4}, which is taken from the error rates section, is the probability of closing all of the valves and not reopening them as well, as failure of an independent checker to notice the valves in an incorrect position and 0.044 is the probability that the operator does not notice the problem and correct it.

There are other permutations of common cause which include combinations of random failures, maintenance outages, and states of the electric power system. However, the resulting system unavailability contribution from this is at least two orders of magnitude less than any contributor already calculated.

*See Tables 1.5.2.3.9-1A and 1B.

TABLE 1.5.2.3.9-9

INDIAN POINT 2 AFWS
PLANT SPECIFIC MAINTENANCE EXPERIENCE

Motor-Driven Pump Trains: (Table 1.5.1-12B)	
Outages	2
Total Duration of Outage Hours	92
Total Reported Operation Hours	35,664
Mean Unavailability (per train)(1) = 2.26×10^{-3}	
Turbine-Driven Pump Train: (Table 1.5.1-12A)	
Outages	6
Total Duration of Outage Hours	242
Total Reported Operation Hours	17,832
Mean Unavailability(2) = 4.56×10^{-3}	

(1) The mean was derived from Section 1.5.1 (see Figure 1.5.1-14).
(2) The mean was derived from Section 1.5.1 (see Figure 1.5.1-13).

TABLE 1.5.2.3.9-10

INDIAN POINT 2 COMMON CAUSE CANDIDATES FOR SIMILAR PARTS
(Number of cutset combinations)

Part	Minimum Cutset Order							
	1	2	3	4	5	6	7	8
Air-Controlled Valves				12		4		
Electric Train								
Check Valves			45	220	317	86	24	
Electrical Components		4						
Motor Operator								
System Air								
Pump			1					
Steam Generator								
Turbine								
Tank		1						
Manual Valves		2		50	32	352	128	

TABLE 1.5.2.3.9-11

INDIAN POINT 2 AFWS DOMINANT CONTRIBUTORS TO CONDITIONAL UNAVAILABILITY - FULL POWER

Rank	Event Description	Mean Unavailability	Approximate Unavailability Contribution (percent)
1	Failure of the CST water supply and of the city water supply (Table 1.5.2.3.9-8A, cutset 1)	1.02×10^{-5}	51.5
2	Operator failure to open the city water valves coupled with a failure of the CST water supply (Table 1.5.2.3.9-8G, cutset 1)	5.47×10^{-6}	27.9
3	Common cause failure to restore the motor-driven pump and turbine-driven pump discharge gate valves after tests (Table 1.5.2.3.9-8J)	2.48×10^{-6}	12.7
4	Operator failure to start the turbine-driven pump and open valves 405A, B, C, and D, plus failure of the two motor-driven pumps (Table 1.5.2.3.9-8G, cutset 4)	3.43×10^{-7}	1.8
5	Turbine pump maintenance coupled with failure of both motor-driven pumps (Table 1.5.2.3.9-8D, cutset 1)	2.24×10^{-7}	1.1
6	Operator failure to start the turbine-driven pump, and open valves 405A, B, C, and D, maintenance on one and failure of the other motor-driven pump (Table 1.5.2.3.9-8G, cutset 1)	2.22×10^{-7}	1.1
7	Operator failure to start the turbine-driven pump, and open valves 405A, B, C, and D, failure of one motor-driven pump train, and a failure of either discharge valve train of the remaining motor-driven pump (Table 1.5.2.3.9-8G, cutset 4)	1.76×10^{-7}	0.9
8	Turbine-driven pump maintenance coupled with failure of one motor-driven pump train, and a motor-driven pump discharge valve train failure in the other motor pump train (Table 1.5.2.3.9-8A, cutset 2)	1.15×10^{-7}	0.6
9	Failure of all three pumps (Table 1.5.2.3.9-8A, cutset 2)	1.03×10^{-7}	0.5
	Total	1.96×10^{-5}	100.0

TABLE 1.5.2.3.9-12

INDIAN POINT 2 AFWS DOMINANT CONTRIBUTORS TO CONDITIONAL UNAVAILABILITY - ONE BUS UNAVAILABLE

Rank	Event Description	Mean Unavailability	Approximate Unavailability Contribution (percent)
1	Operator failure to start the turbine-driven pump and open valves 405A, B, C, and D coupled with a failure of the remaining motor-driven pump (Table 1.5.2.3.9-8H, cutset 1)	4.90×10^{-5}	30.2
2	Turbine-driven pump maintenance coupled with a failure of the remaining motor-driven pump (Table 1.5.2.3.9-8E, cutset 1)	3.19×10^{-5}	20.0
3	Operator failure to start the turbine-driven pump and open valves 405A, B, C, and D coupled with maintenance of the remaining motor-driven pump (Table 1.5.2.3.9-8H, cutset 1)	1.60×10^{-5}	9.9
4	Failure of the turbine-driven pump train, and failure of the motor-driven pump train that still has electric power (Table 1.5.2.3.9-8B, cutset 1)	1.45×10^{-5}	9.0
5	Operator failure to start the turbine-driven pump and open valves 405A, B, C, and D coupled with a loss of either motor-driven pump discharge valve train associated with the remaining pump (Table 1.5.2.3.9-8H, cutset 3)	1.26×10^{-5}	7.8
6	Failure of the CST water supply and failure of the city water supply (Table 1.5.2.3.9-8B, cutset 2)	1.02×10^{-5}	6.3
7	Turbine-driven pump maintenance coupled with a failure of either motor-driven pump discharge valve train associated with the motor-driven pump having power (Table 1.5.2.3.9-8E, cutset 2)	8.22×10^{-6}	5.1
8	Operator failure to open the city water valves and failure of the CST water supply (Table 1.5.2.3.9-8H, cutset 4)	5.47×10^{-6}	3.4
9	Motor-driven pump maintenance coupled with a failure of the turbine-driven pump train (Table 1.5.2.3.9-8E, cutset 3)	4.67×10^{-6}	2.9
10	Failure of the turbine-driven pump train, and failure of a motor-driven pump discharge valve train on the functioning pump (Table 1.5.2.3.9-8B, cutset 3)	3.73×10^{-6}	2.3
11	Common cause failure to restore the motor-driven and turbine-driven pump discharge gate valves after tests (Table 1.5.2.3.9-8K)	2.48×10^{-6}	1.5
	Total	1.62×10^{-4}	100.0

TABLE 1.5.2.3.9-13

INDIAN POINT 2 AFWS
DOMINANT CONTRIBUTORS TO CONDITIONAL UNAVAILABILITY - NO POWER

Rank	Event Description	Mean Unavailability	Approximate Unavailability Contribution (percent)
1	Failure of the operator to start the motor-driven pump (Table 1.5.2.3.9-8I, cutset 1)	7.00×10^{-3}	51.1
2	Turbine-driven pump maintenance (Table 1.5.2.3.9-8F, cutset 1)	4.56×10^{-3}	33.8
3	Failure of the turbine-driven pump train (Table 1.5.2.3.9-8C, cutset 1)	2.07×10^{-3}	15.1
	Total	1.37×10^{-2}	100.0

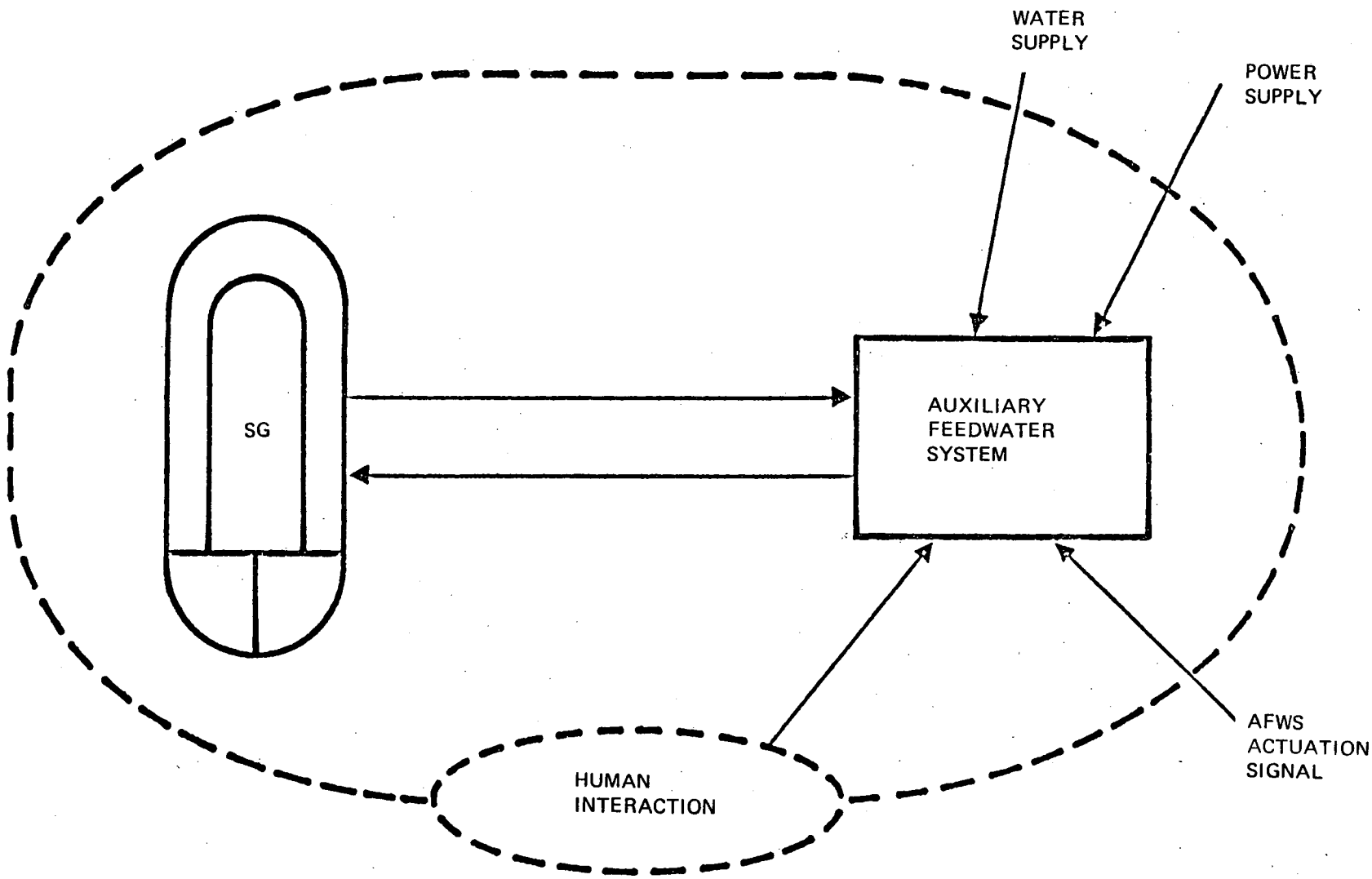


Figure 1.5.2.3.9-1. Indian Point 2 Auxiliary Feedwater System Boundary of Analysis

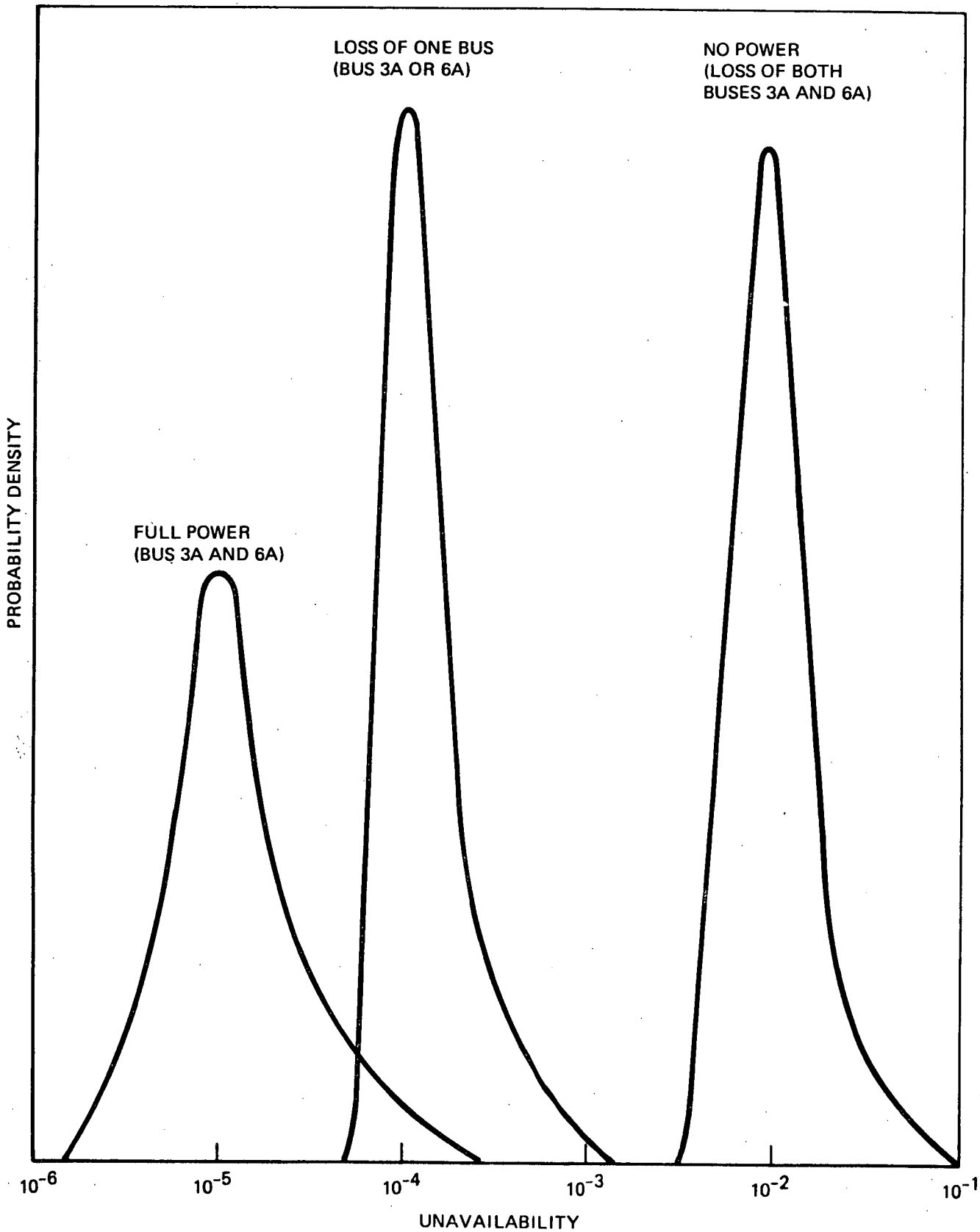


Figure 1.5.2.3.9-2. Indian Point 2 Auxiliary Feedwater System Unavailability Probability Distributions

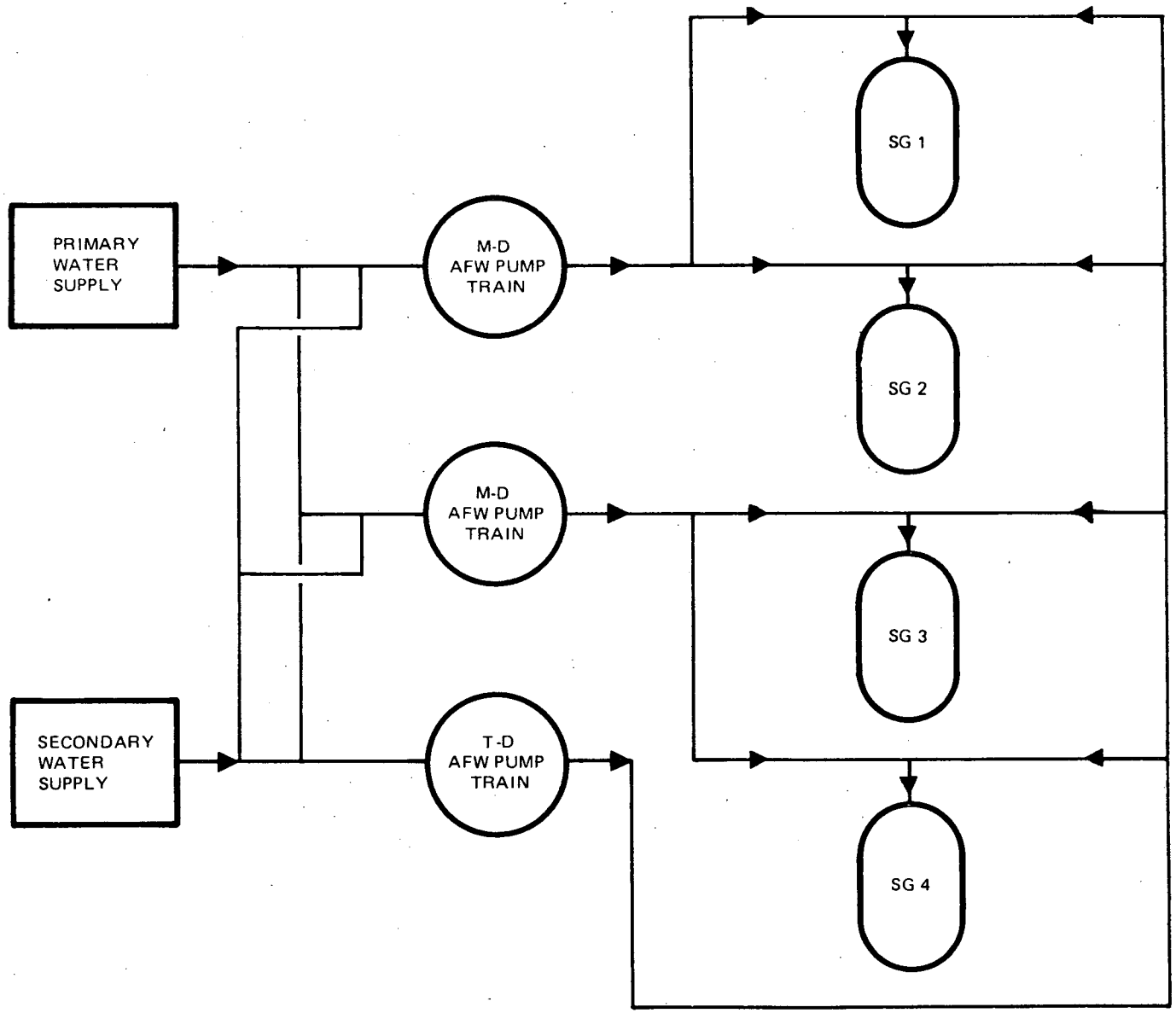


Figure 1.5.2.3.9-3. Indian Point 2 Auxiliary Feedwater System Simplified Block Diagram

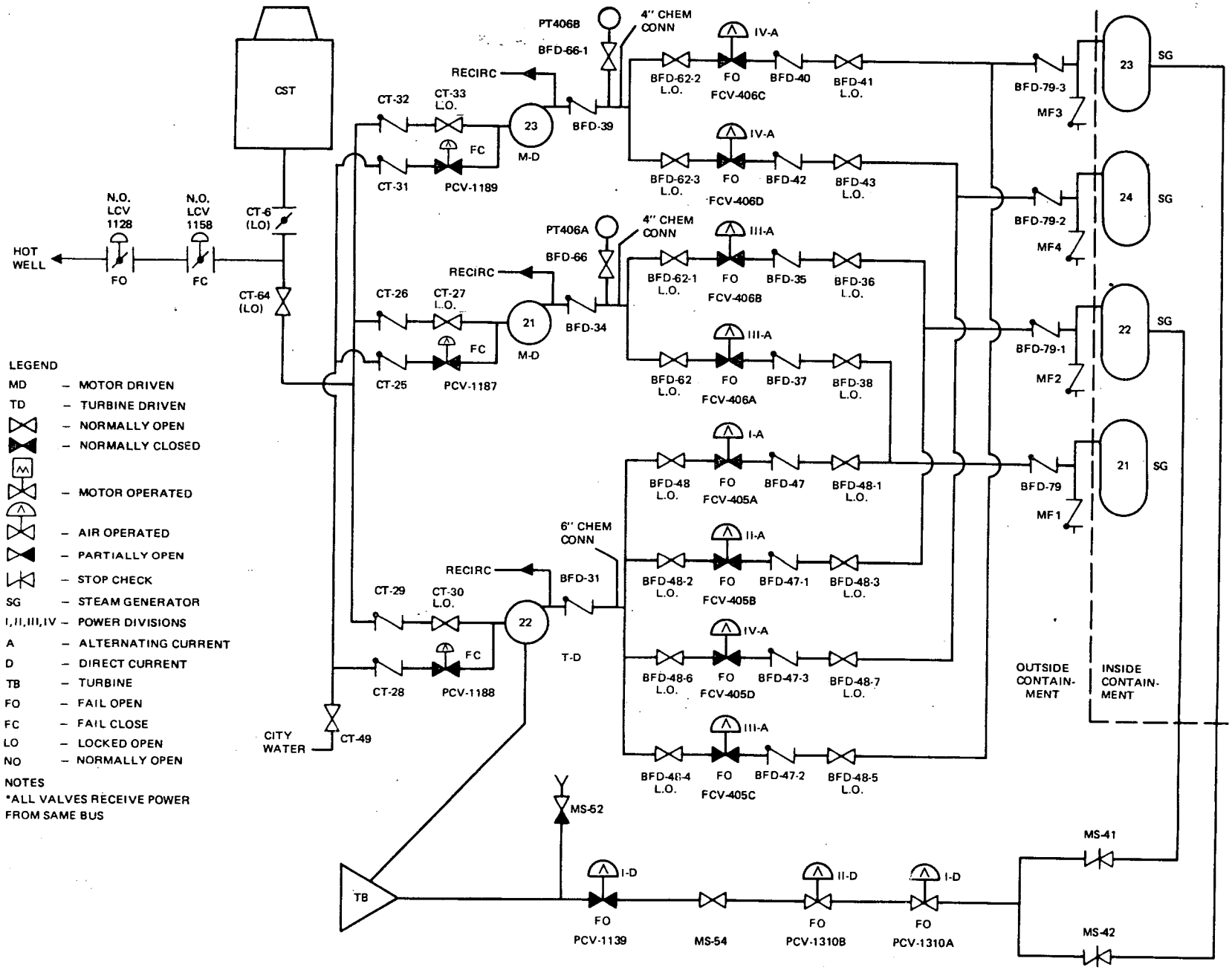


Figure 1.5.2.3.9-4. Indian Point 2 Auxiliary Feedwater System Schematic

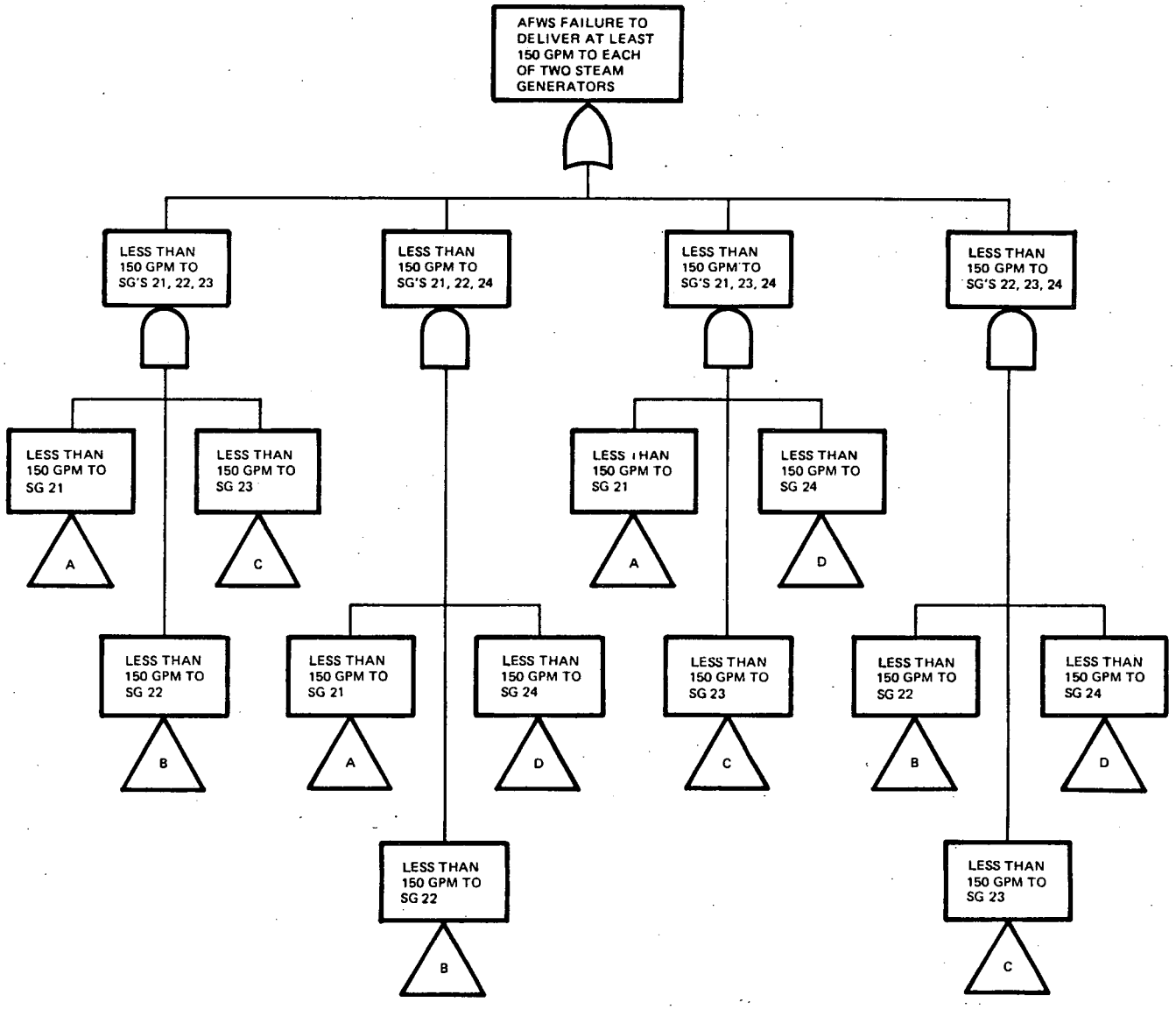
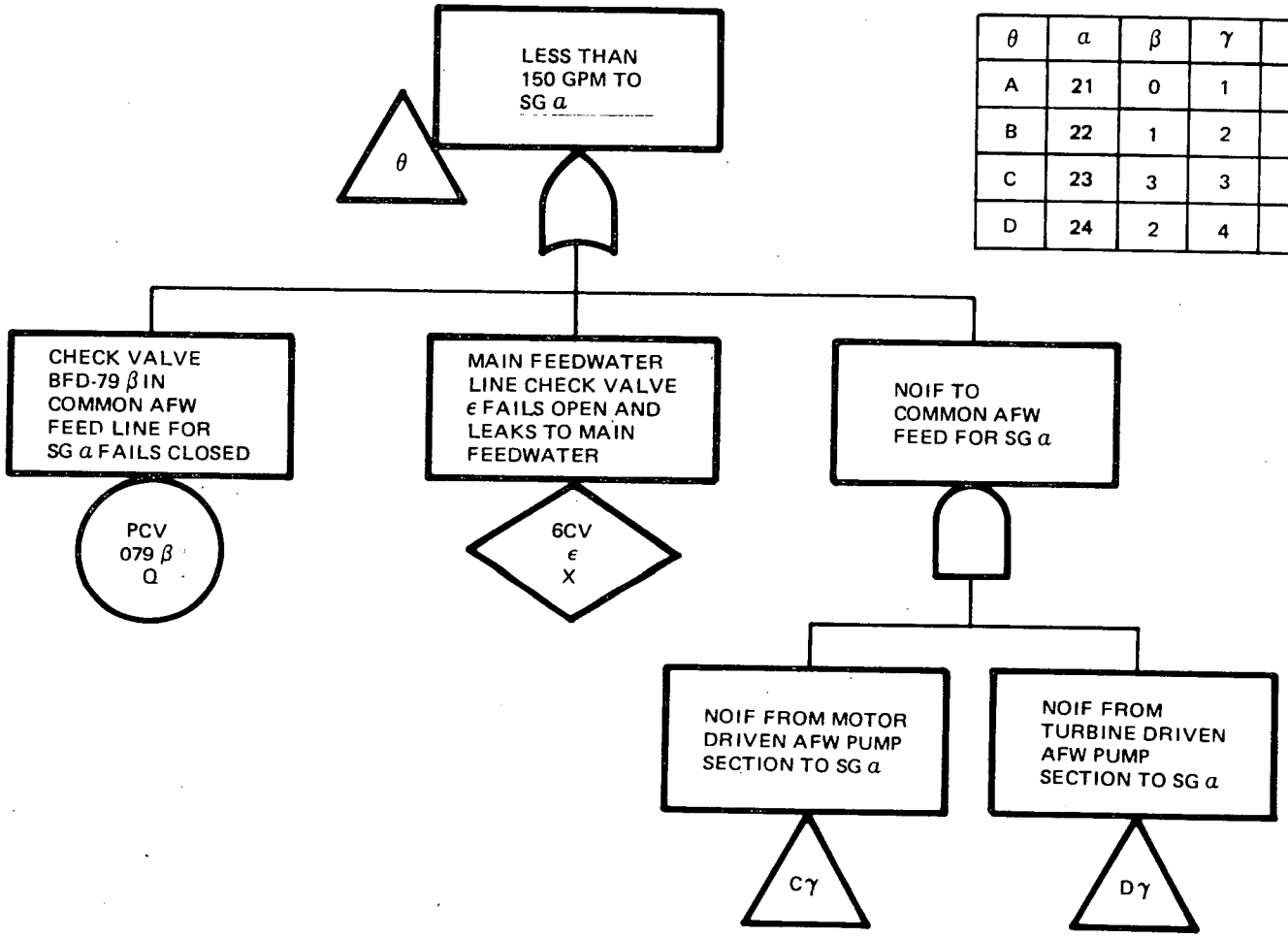
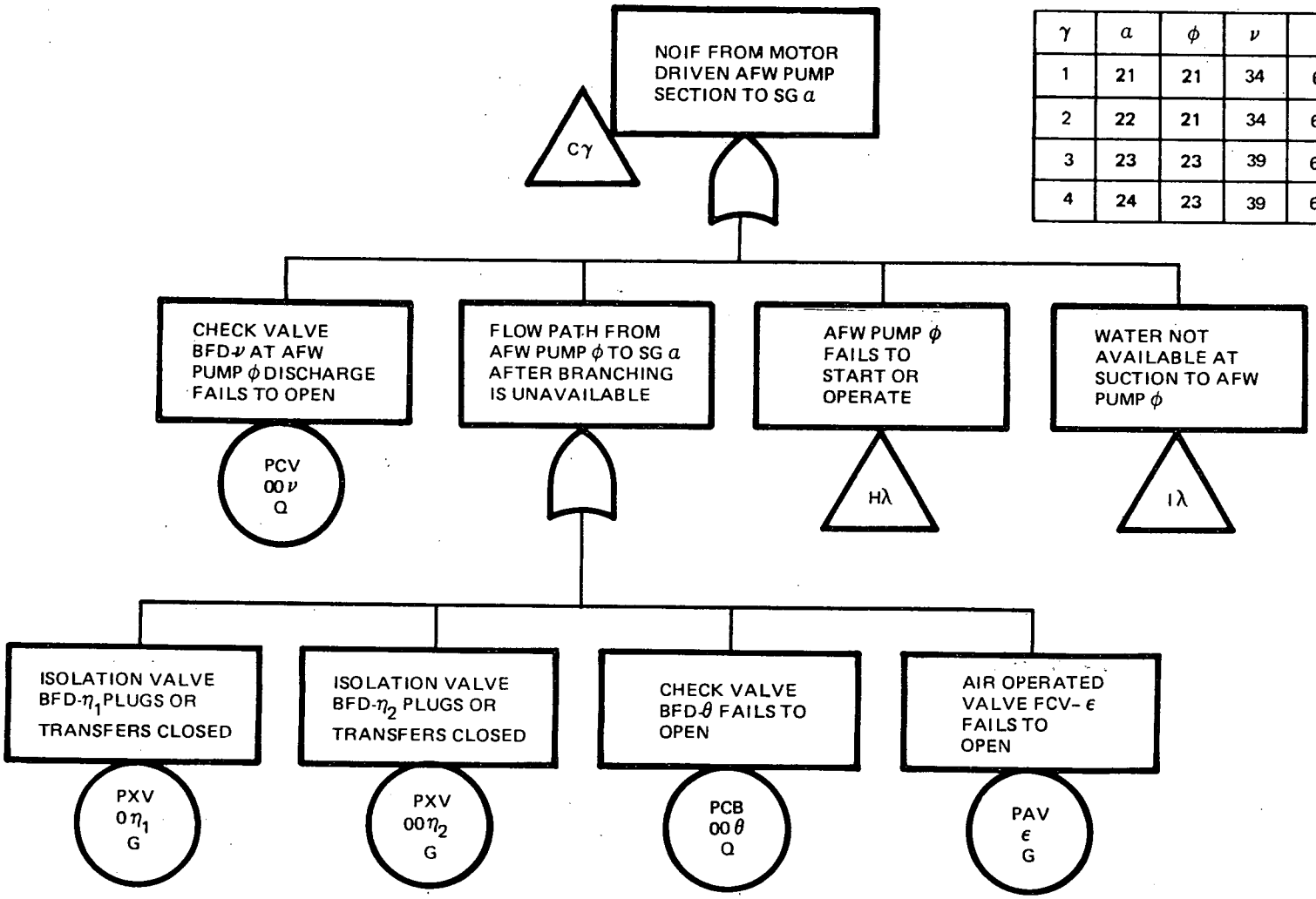


Figure 1.5.2.3.9-5. Indian Point 2 Auxiliary Feedwater System Fault Tree (Sheet 1 of 10)



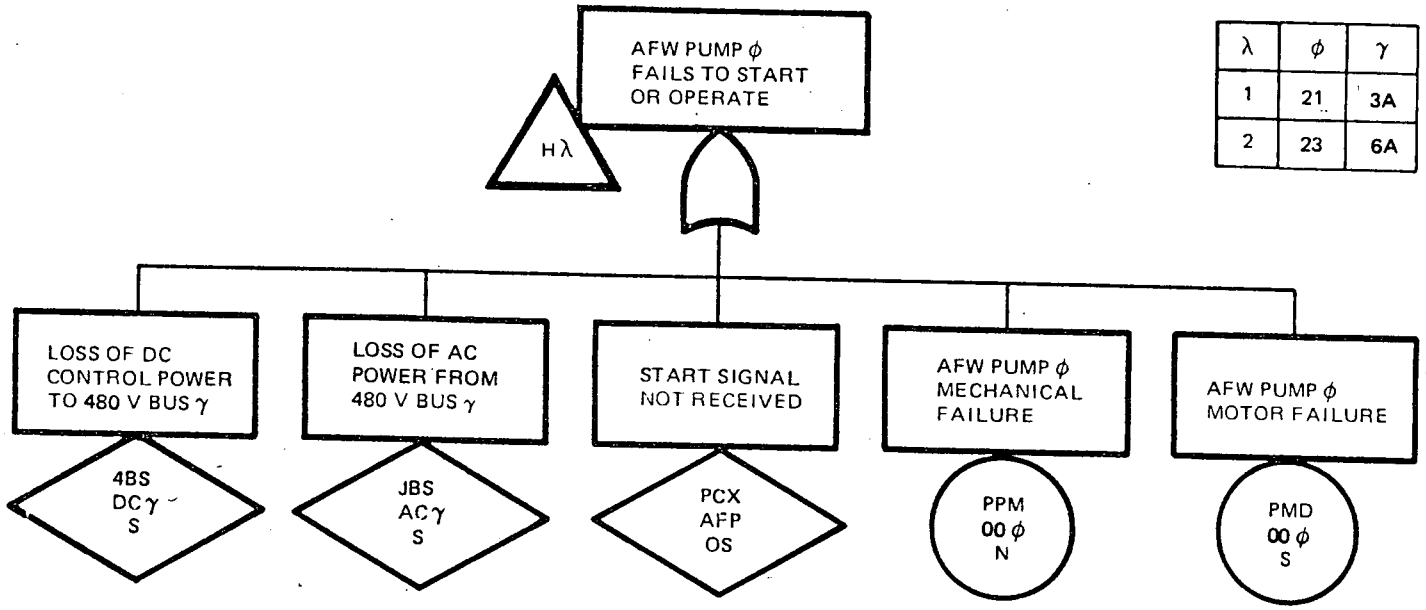
θ	α	β	γ	ε
A	21	0	1	001
B	22	1	2	002
C	23	3	3	003
D	24	2	4	004

Figure 1.5.2.3.9-5. (Sheet 2 of 10)



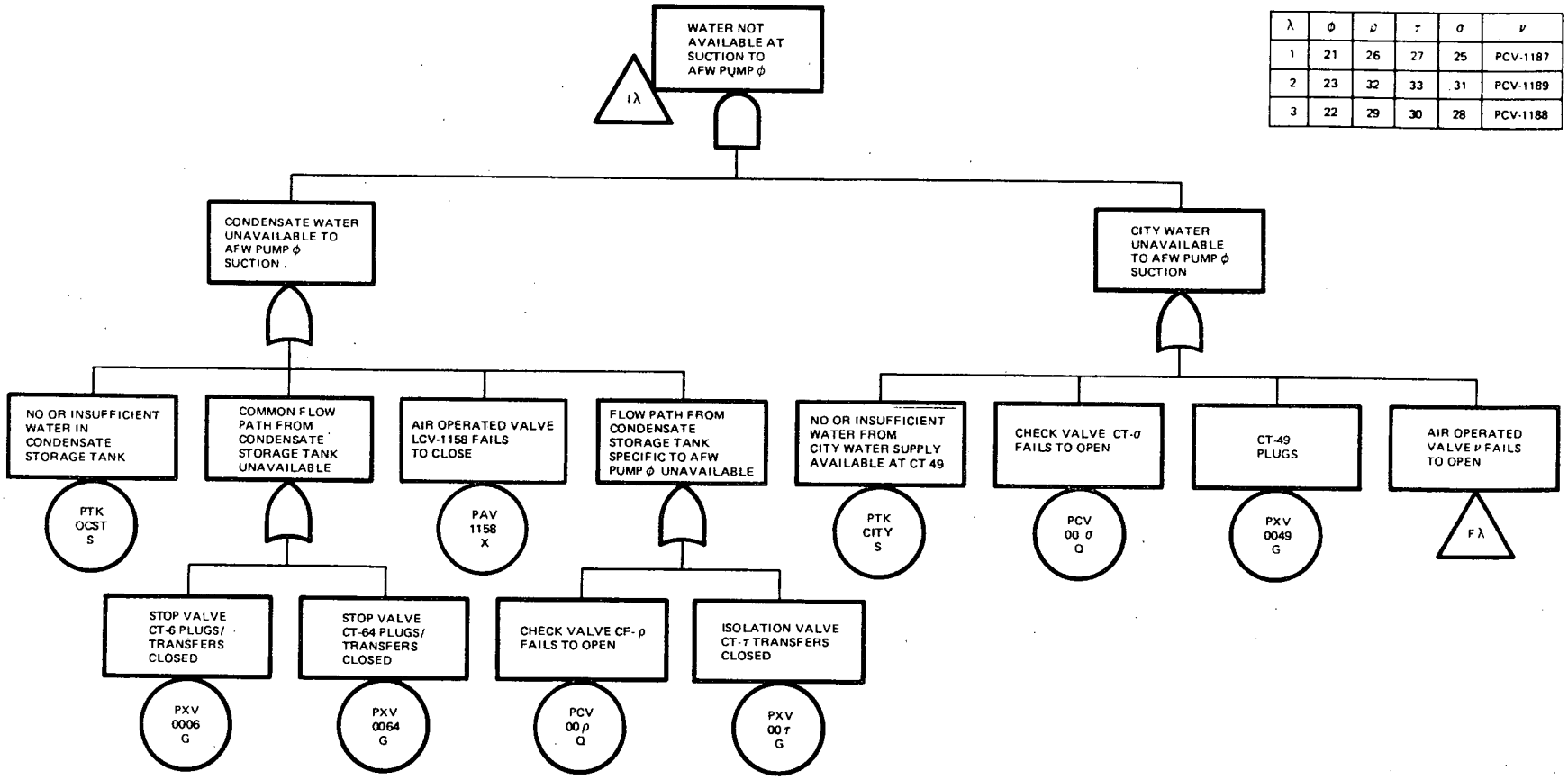
γ	α	ϕ	ν	$\eta 1$	$\eta 2$	θ	ϵ	λ
1	21	21	34	62-0	38	37	406A	1
2	22	21	34	62-1	36	35	406B	1
3	23	23	39	62-2	43	42	406C	2
4	24	23	39	62-3	41	40	406D	2

Figure 1.5.2.3.9-5. (Sheet 3 of 10)



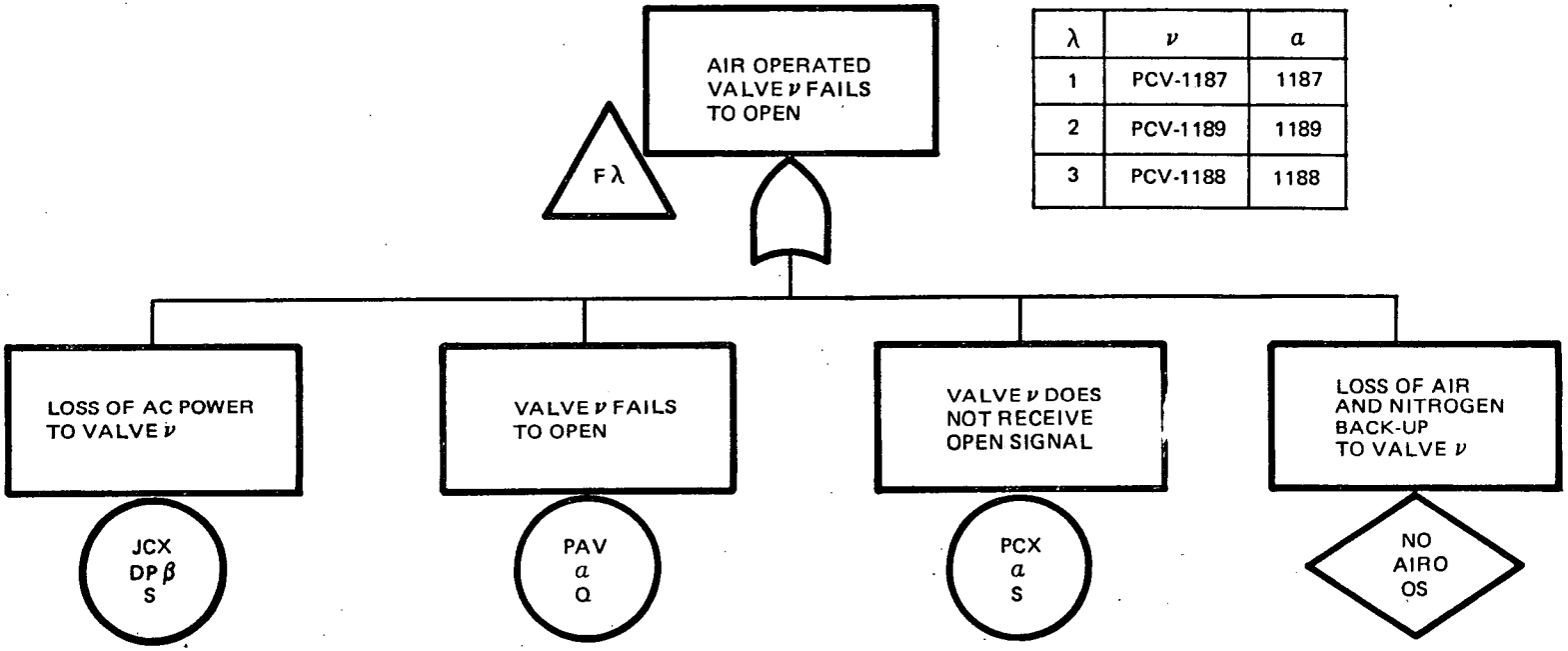
λ	φ	γ
1	21	3A
2	23	6A

Figure 1.5.2.3.9-5. (Sheet 4 of 10)



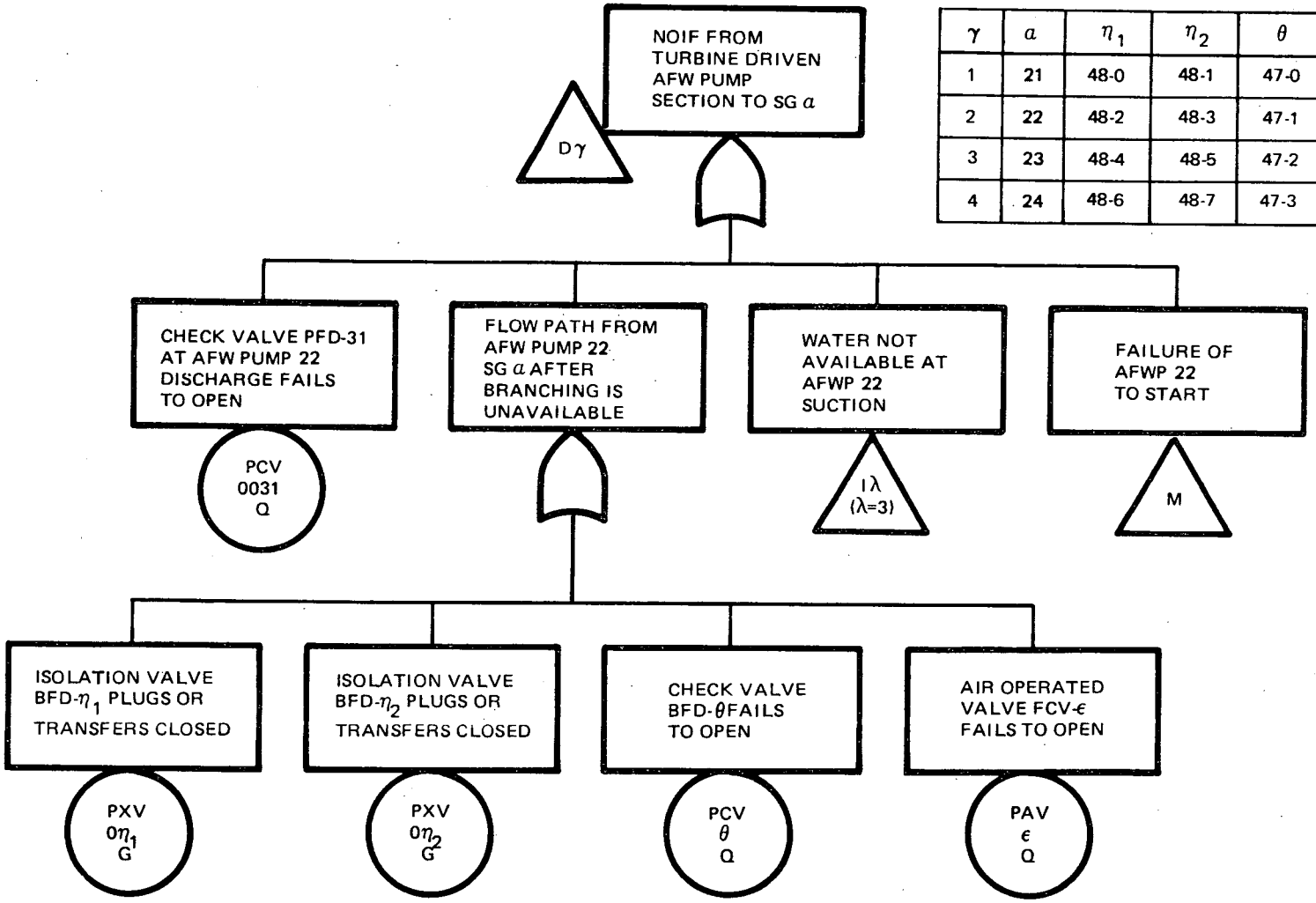
λ	φ	ρ	τ	σ	ν
1	21	26	27	25	PCV-1187
2	23	32	33	31	PCV-1189
3	22	29	30	28	PCV-1188

Figure 1.5.2.3.9-5. (Sheet 5 of 10)



λ	ν	a
1	PCV-1187	1187
2	PCV-1189	1189
3	PCV-1188	1188

Figure 1.5.2.3.9-5. (Sheet 6 of 10)



γ	α	η_1	η_2	θ	ϵ
1	21	48-0	48-1	47-0	405A
2	22	48-2	48-3	47-1	405B
3	23	48-4	48-5	47-2	405C
4	24	48-6	48-7	47-3	405D

Figure 1.5.2.3.9-5. (Sheet 7 of 10)

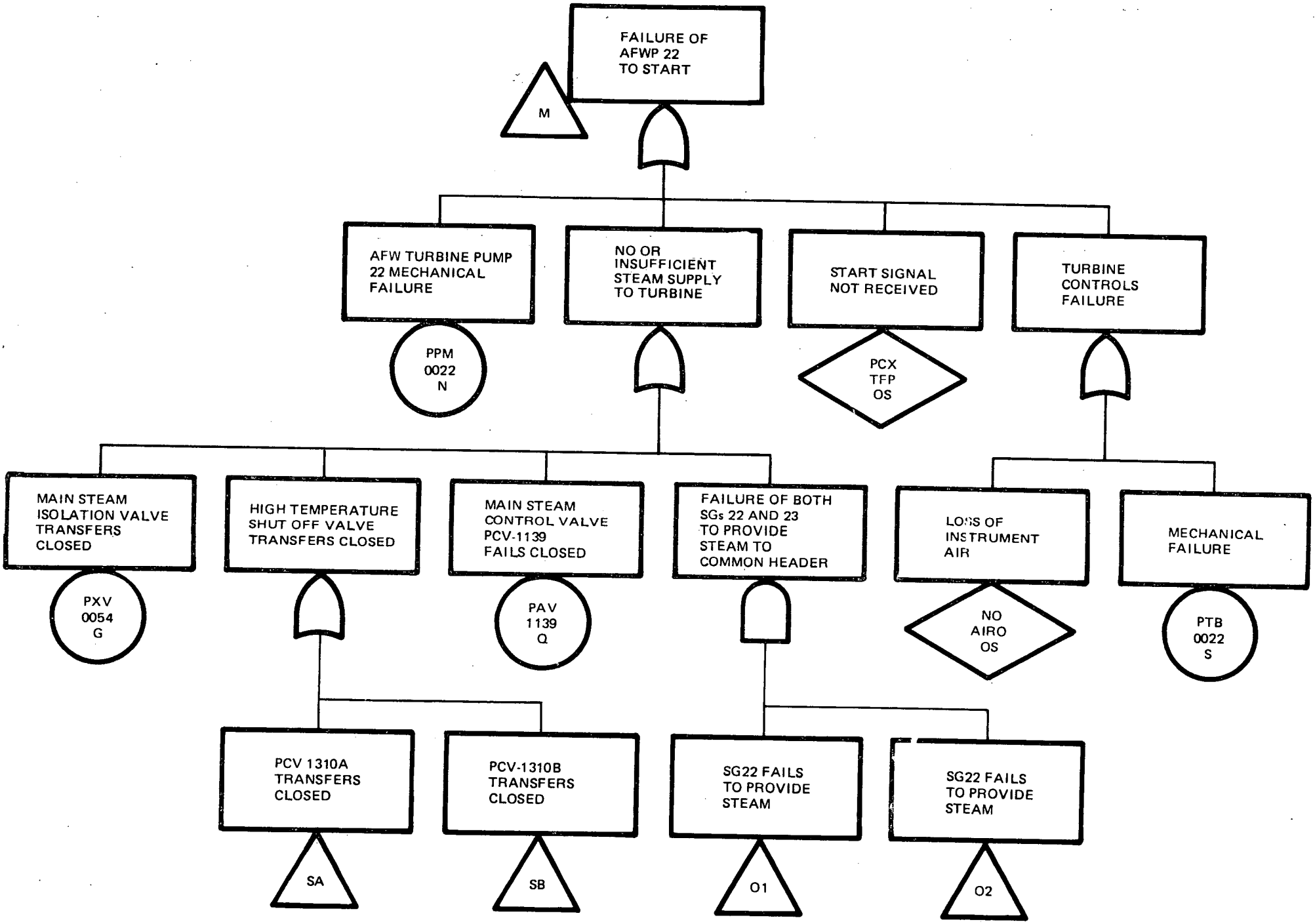
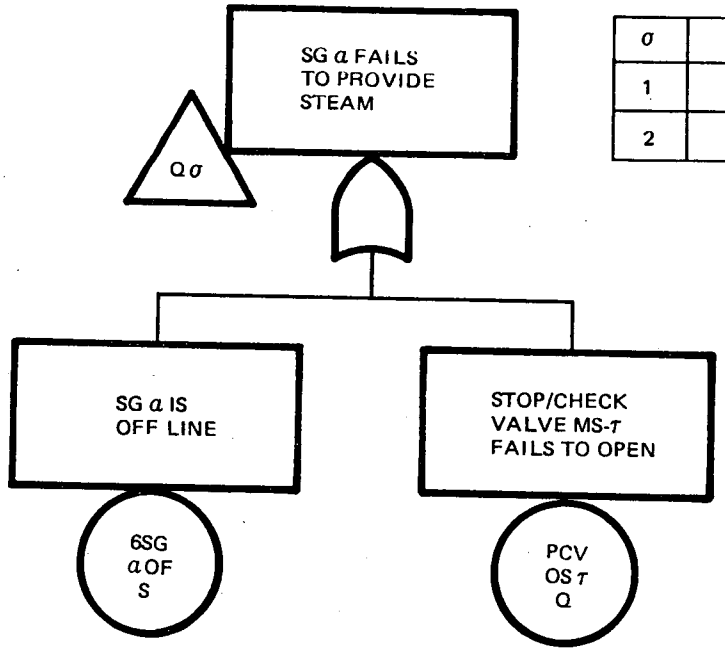


Figure 1.5.2.3.9-5. (Sheet 8 of 10)



σ	α	τ
1	22	41
2	23	42

Figure 1.5.2.3.9-5. (Sheet 9 of 10)

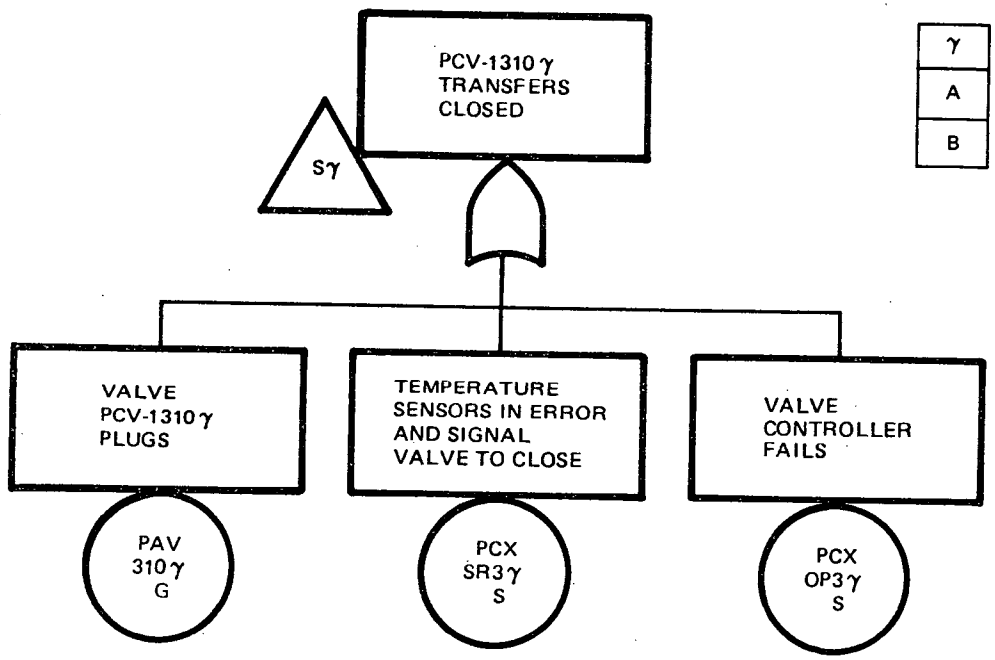


Figure 1.5.2.3.9-5. (Sheet 10 of 10)

1.6 INDIAN POINT UNIT 3 APPENDICES: DATA AND SYSTEMS ANALYSES

1.6.1 INDIAN POINT UNIT 3 DATA ANALYSIS

The methods for the analysis of data within the probability of frequency framework are described in Section 0, Probabilistic Risk Assessment Methodology. This section contains the implementation of the methodology for the derivation of generic and site specific distributions for the rates of occurrence of elemental events.

1.6.1.1 Site Specific Failure Data Base Development

1.6.1.1.1 Component Failure Data

1.6.1.1.1.1 Failure Definition. The site specific component failure information developed in this data base is used as a basic input to the Bayesian specialization of available generic component failure distributions. These specialized distributions are applied to the corresponding components in each of the system fault trees during the quantification of hardware failure contributions to system unavailability. In this context, the definition of component failures used for this data base includes only those hardware failures which can be identified as attributable to an intrinsic property or state of the component or subsystem being analyzed. Specifically excluded from this data base are failures attributable to:

- Personnel errors and procedural errors. These failures are included in the analysis of human interactions with components and systems during operation, testing, and maintenance activities.

- Causes generated by systems or components external to the component being analyzed. These failures are identified and included in the analysis of interfacing components and systems, and their effects are quantified through the analysis of system interdependencies and common cause initiators.

- Design, fabrication, and installation errors (for which documented corrections have been implemented and sufficient operating experience has been accumulated to demonstrate the efficacy of such corrections). Corrected errors are not considered as contributors to failure. Consideration and quantification of unidentified or latent uncorrected design, fabrication, and installation errors are included in each system analysis, independent of hardware failures.

Descriptions of the specific failures included and, if appropriate, excluded from this data base are provided with the individual component failure mode data summaries presented in Section 1.6.1.15.

1.6.1.1.1.2 Failure Data Sources. The primary source of basic component failure data used in this study was the Licensee Event Reports (LERs). The technical specifications and plant operating license reporting criteria require that LERs be submitted to the NRC as

documentation of all significant events that directly affect plant safety or affect those systems designed to maintain the plant in a safe condition. A compilation of all LERs submitted by Indian Point Unit 3 from prestartup construction in 1969 through December 1979, provided the basic event descriptions from which the corresponding failure items were drawn and evaluated for inclusion in the data base.

The information included in any source document cannot be directly used to construct a specific failure data base without first identifying, documenting, and understanding the constraints and implications associated with that information. Those constraints are discussed herein. Meanwhile, the LERs have significant advantages over other primary failure data sources for use in probabilistic risk assessment (PRA).

- The reporting criteria specify that all events affecting safety systems accident mitigation capabilities must be reported. Because this study is specifically concerned with the analysis of these capabilities, all LER items should be directly relevant to the development of this data base.

- Failures are generally reported for the plant operating modes that are of primary concern in this study: power operation and, in some cases, hot shutdown.

- The LERs are a source of relatively consistent, reviewed, and generally complete event descriptions. Because each observed event must be evaluated relative to common reporting criteria, the items reported in the LERs provide a relatively consistent information base that can be applied across different systems in any given plant. To a much lesser extent, due to the inherent subjectivity of intent interpretation and due to subtle differences in the criteria applied and technical specifications limitations imposed at different plants, these general reporting criteria also provide a basis for broad consistency in the types and applicability of events reported from several plants. However, direct comparisons of these reports cannot be made without full evaluation of the bases for and application of the specific reporting criteria at each individual station.

- The LERs provide a fully verifiable source of primary component failure data. Because all the other available sources of failure information are subject to many of the same limitations that apply to the LERs, a principal advantage in using the LERs in this study is that they are a uniquely verifiable source of data and are readily available to all potential users and review personnel.

A number of additional sources of primary component failure data were also used if more detailed information on specific items was needed than was available in the LER summaries. These sources included control room equipment operating logs, component maintenance records, testing records, and station internal event reporting documents [Significant

Occurrence Reports (SORs)]. The SORs are a large volume of raw data covering a wide range of events documented during all phases of plant operation. They thus provide a complete record of all component failures observed at the station. (The SORs are the preliminary documents for all failures that are ultimately reported as LERs.) However, because of the volume, variability, and lack of detail in the SORs, they were primarily used as reference documents for this study. No detailed effort was made to reduce their information content to a form directly applicable to this data base.

The primary concerns in the development of this site specific data base were that it must be: (1) internally consistent, and (2) fully verifiable. Because of these concerns, any modifications, additions, or deletions made to the failure data reported in the LERs have been applied only when specific documentation was available to fully justify such modifications. In all such cases, this documentation or a direct reference to its source is provided with the affected component failure mode data summary.

It is important to make a few observations about the limitations of existing data sources, including LERs, with respect to probabilistic risk assessment work. First, a comprehensive data collection system designed specifically to support PRA does not exist. The existing data systems have all evolved from either licensing related criteria or plant performance analysis requirements. For example, PRA does not draw boundaries around systems according to safety system classifications or technical specifications. Rather, the scenarios and event sequences define the systems and, therefore, the data of interest. The result is that some failures and failure modes useful for PRA analysis may not be reported if the plant sticks only to safety criteria. The same applies to plant operating conditions.

Additionally, regardless of the data system, judgment is always involved. All failures require some interpretation by the plant staff--was it a failure, is it a reportable event, what is the mode, the apparent cause, etc.

Recognizing the limitations of LERs as a data source for PRA, an effort was made to review detailed station records at Indian Point 3 to ensure that the LERs provided a representative data base for Indian Point. The data base used is believed to be sound. Where uncertainties exist, the probabilistic framework accommodates quantification of such uncertainties.

1.6.1.1.2 Component Operability Tests and Service Hours Data

1.6.1.1.2.1 Data Base Definition.

1.6.1.1.2.1.1 Operating Modes. The distinction between cold and noncold shutdown (i.e., hot shutdown or power operation) conditions in plant operating modes is important for the development of a site specific failure data base that uses the LERs as the primary source of

component failure information. The principal reasons for distinguishing between these two modes (as opposed to modes such as power operation versus shutdown, or critical versus noncritical) are:

- LER reporting criteria are significantly different when the plant enters the cold shutdown condition (very few events which occur during cold shutdown are reportable).

- The technical specifications operability criteria for safety systems and components generally specify that operability restrictions do not apply during cold shutdown.

- Operating, maintenance, and system testing procedures and practices are modified significantly when the plant enters the cold shutdown condition.

- The plant operating modes of primary concern in this study are power operation and, in some cases, hot shutdown.

Table 1.6.1-1 summarizes the periods since initial reactor criticality during which Indian Point 3 was in the cold shutdown mode of operation. Only operating times between April 26, 1976 (initial criticality) and December 31, 1979, were included in this failure data base. This time span was based on the availability of failure event information from the LERs, and the operability, testing, and reporting criteria specifically applied following initial criticality.

1.6.1.1.2.1.2 Testing Frequencies. Periodic testing that is required by the plant technical specifications is generally performed monthly (during power operation), quarterly (during any calendar quarter for which the unit was not in continuous cold shutdown), annually, or during regular refueling outages. Variable frequency testing that is not required by the technical specifications is performed as specified in the individual test procedures and as plant operating conditions allow. The operating periods summarized in Table 1.6.1-1 and the general testing frequency criteria outlined were used to develop the periodic testing data shown in Table 1.6.1-2. As an example of the use of this frequency data, consider component "X," which, according to the station's periodic testing procedures, is tested monthly during power operation. The total number of tests performed on component "X" between initial criticality and the end of 1979 is 40. If component "Y" is tested quarterly, then the total number of component tests for "X" and "Y" together is 54.

1.6.1.1.2.2 Component Test Data Synthesis. Specific details of the number of component tests performed at each of the periodic testing intervals are provided with the individual component failure mode data summaries in Section 1.6.1.1.5. The number of tests listed for each interval is the total number of component tests performed at that interval. The total number of component tests in the period is the

product of this periodic test data and the testing frequency data presented in Table 1.6.1.1-2. For example, consider the following:

- Test 1 is performed monthly and verifies the operability of three motor-operated valves.
- Tests 2 and 3 are each performed quarterly and verify the operability of 1 and 18 motor-operated valves, respectively.
- No other tests are performed to verify motor-operated valve operability.
- The total number of valve tests per month is three.
- The total number of valve tests per quarter is 19.
- The total number of valve tests for the data base period is: 3(40) + 19(14) = 386 valve tests (from 1976 to 1979).

All the station's periodic test procedures were reviewed to identify the specific components tested and the failure modes verified by each of these procedures. For many of the failure modes presented in the data base (e.g., motor-driven pump failure to start on demand), specific operations performed during the testing process provided direct evidence of component operability (e.g., start pump "X"). For a large number of failure modes, however, no analogous specific operations were provided to directly verify component successes. The number of corresponding actual component tests was determined by noting the success criteria and parameters monitored in each testing procedure. This information was combined with the applicable system piping and instrumentation diagrams with flow path configurations altered, if necessary, as they are affected by the testing procedure. Successful component tests were counted only if: (1) the testing procedure provided direct evidence of successful operation or an unfailed state of the component, and (2) a failure of the component would have resulted in an unsuccessful test requiring an LER. For example, consider the component failure mode "manual valve transfers closed." Referring to the example piping diagram shown in Figure 1.6.1-1, a system flow test is performed to verify the operability of pump X by closing motor-operated valve A and running the pump on recirculation flow. Successful performance of the test requires that the pump start and that adequate flow be observed at flow gauge F. This test, in addition to verifying pump X operability to start and run, provides the following test data information:

- The piping from the suction source through the recirculation line is not plugged.
- Check valve C opens successfully.
- Manual valves M1, M2, and M3 are open.

The test does not provide any information about the status of motor-operated valve A or manual valve M4, because they are not included in the test flow path. (Excessive leakage through A could be detected if a flow path was available downstream from A, if valve M4 had not failed closed, and if the leakage were sufficient to degrade the flow through F. However, this failure of A would not be detected if valve M4 had also failed. Because this test cannot detect this failure of M4, these valves are not included in the success data.) This general process was applied to all the systems analyzed in this study for periodic testing and normal operating configurations to develop the successful testing data to be combined with these (generally passive) component failure modes. In all such cases, the application of this methodology is specifically referenced in the data summaries for the applicable component failure modes.

1.6.1.1.2.3 Component Service Hours Data Synthesis. The service hours data reported in the component failure mode data summaries was developed by analyzing the following three general states of operability verification:

1. Components whose operability is monitored continuously during normal plant operating conditions.

2. Components whose operability is verified during periodic testing and whose state does not change between tests.

3. Components whose operability is verified only during the periodic tests.

For those components that are in continuous service during normal plant operation, the only times included in the service hours are those when failure of the component would be reportable as an LER. (For example, if pump "X" is normally running during all modes of unit operation, and the technical specifications require that its failure be reported only during noncold shutdown periods, the cold shutdown running hours are excluded from the pump service hours data.) For those components whose state remains unchanged between periodic tests, the service hours include only the periods between such tests during which the component failure would be reportable as an LER. (For example, valve "Y" is verified open during a quarterly system flow test, as described in Section 1.6.1.1.2.2, and a failure of the subsystem of which "Y" is a portion is required to be reported only during noncold shutdown periods. If the unit is placed in cold shutdown for 1 month between quarterly tests, the total service period applied to "Y" during that quarter is only 2 months, because a failure detected during the cold shutdown month, by any method, would not be reported and because a system operability verification test required to be performed prior to leaving cold shutdown would establish Y's operability for the remainder of the period.) For those components whose operability is verifiable only during the periodic tests, the service hours include only the applicable test operating times. (For example, if pump "Z" is operated only during a monthly flow test, the service hours applied to the pump

failure mode "fails during operation" include only the pump's actual monthly pump operating hours.) In all cases, the criteria used to establish the component service hours data for the specific failure mode reported are documented with the failure mode data summaries in Section 1.6.1.1.6.

1.6.1.1.3 Component Failure Mode Definition

In most cases, the specific component failure mode of interest in this study has been defined by the type of component and its function within the system being analyzed (e.g., "check valve fails to open"). In some cases, however, the reported failure modes have been defined by a combination of influences including the level of detail to which the systems are modeled in the fault tree analyses and the level of detail available in the generic failure data distributions.

In principle, the site specific failure data should be traceable not only to a specific component, but also to a subcomponent and a "subfailure" level (e.g., check valve "X" failed to open because 3/4-inch bolt "A" became corroded due to interaction with caustic solution "Q," etc.). However, the system fault trees are not developed to this level of detail. This is because microscopic analysis generally reduces understanding of the relevant system failure modes and of the dominant failure contributors, and instead focuses attention on a narrowly defined analysis of aggregates of individual subcomponents. In addition, in most cases, the actual data is not as well defined at this microscopic level of detail as it is at the macroscopic component level. (For example, the check valve may have failed to open because of bolt corrosion or because of hinge pin swelling, but it did fail to open.) Therefore, the actual state of knowledge about component failures is often clearest only for a combination of subcomponent failure modes which are manifested in a single observable, verifiable, and simply documentable effect. In addition, as a practical consideration, the generic data distributions to be specialized with the site specific failure data are usually not available in the literature at the level of detail which can be generated from the site specific failure data sources. In most of these cases, similar component types and failure modes have been combined in the site specific data base to provide consistency and compatibility between these two data sources.

Specific examples of items for which the site specific component failure mode definition has been strongly influenced by the available level of generic data include:

- Motor-Operated Valves Failure to Operate on Demand. The generic data distribution for motor-operated valve active failures is best defined for the failure mode "fail to operate," which includes the failure modes "fail to open" and "fail to close." Because the precise contributions of each of these modes to the generic data cannot be discerned and both of these failure modes actually define a failure of the valve to change states on demand, the more detailed

site specific data have also been combined into the single "fail to operate" mode. (In this case, a test which fully cycles a valve open-closed-open strictly constitutes one test each of the failure modes "fail to close" and "fail to open". Either of these failures would be reported as a "failure to operate" and only one failure would be reported for the test. Therefore, the entire cyclic test is conservatively counted as a single test of the valve failure mode "fail to operate".)

- Motor-Operated Valves and Manual Valves Transfer Closed (or transfer open). Because the failure causes are physically similar for motor-operated and manual valves (no evidence is available from the site specific data to indicate that spurious operation of the motor operator contributes significantly to differences between the two valve types), and because only a single generic distribution is available for each of these failure modes, motor-operated and manual valves are combined into a single component category for each of these failure modes. (Air-operated valves are documented separately, however, because their identifiable failure causes are physically different from those of manual and motor-operated valves.)

- Definition of "Pump" Failure. Power supply circuit breakers, electrical and mechanical controls, motors, pump shafts, and other pump mechanical components are combined into a single component defined as a pump because the generic failure data does not differentiate among failures of these subcomponent categories. Therefore, a pump "failure to start" could be due to a circuit breaker failure, low oil pressure, or a ruptured shaft, but each of these failures would be categorized as a failure of the pump to start.

The component failure mode data reported for motor-driven pumps deserves special attention because these pumps are combined for one type of failure mode, but are retained as independent components for another failure mode. All similarly sized motor-driven centrifugal pumps analyzed in this study are combined in the development of a single "failure to start" failure mode. This is because only a single, well defined generic distribution is available for this failure mode and because the observed causes for a wide variety of different pumps failing to start are physically identical (e.g., circuit breaker failures, control circuit failures, contact failures, etc.). Therefore, the macroscopic data base for this specific failure mode does not differentiate between motor-driven pumps in different systems because all the motor-driven pumps considered in this study exhibit the same failure characteristics on starting. However, even though only a single generic distribution is available for the failure of motor-driven pumps during operation, the motor-driven pumps in each of the systems analyzed in this study exhibit unique operating characteristics attributable to such factors as design, orientation, physical location, and normal operating duty. Therefore, the failure data base has been defined independently for each of these pump types during pump operating periods to take full account of these physical differences. (For example, a

large vertical shaft pump under continuous service will exhibit significantly different operating failures from a horizontal pump located in an adverse environment and subjected to only intermittent starts.) By specializing the single generic distribution for pump failure data (which indicates a relatively diffuse prior state of knowledge about differences between the pumps) with the individual pump site specific failure rate information, these physically observable differences are thus retained as uniquely identifiable contributors to each pump's availability during operation.

1.6.1.1.4 Uncertainty in Site Specific Data

A significant problem with many of the existing generic component failure data bases is their inconsistency in evaluating the numerator and denominator in the failure rate expression (i.e., the number of failures and the corresponding number of tests, operating hours, or demands). The development of a consistent site specific component failure data base for this study included a conscientious effort to ensure that the population success data (the denominator) obtained from the Indian Point 3 records was compatible with the failure data obtained from the LERs.

The basic sources of information used to develop this population success data included plant testing and operating procedures, normal and nonroutine system alignments, and general plant failure and maintenance data records. Each of these sources was evaluated in the context of the Indian Point 3 failure data reporting criteria to determine the applicability of the information. The system flow paths and alignments established by each test and operating procedure were examined to identify the component types and failure modes verified during the applicable period. The plant operating procedures and periodic test schedules provided the necessary input to determine the frequency and duration of the majority of these operations. Plant maintenance records and the technical specifications were used to determine the frequency of nonroutine tests required when equipment was removed from service. For each system configuration, the following questions were asked for each component:

- What failure mode is tested by this configuration?
- Would this failure be detected through either indication during normal system operation or through the acceptance criteria for the test?
- If detected, would the failure be reportable as an LER under the Indian Point 3 technical specifications?

The success data was included only if all of these questions could be answered affirmatively.

Although a few component failures may have been omitted from the data base because of the nature and availability of the LERs, it is believed that it is equally likely that a corresponding percentage of the tests

and operating hours may not have been included because they could not be easily extracted from plant records or because they could not be verified as being compatible with the failure data. Therefore, it is believed that additional data, if it were available, would not change the reported site specific failure rates by more than 10%. Because of the strict criteria applied to the population success data to ensure compatibility with the reported failures, it is also believed that the reported failure rates are likely to be slightly conservative (i.e., additional data would most probably result in a slight reduction of the failure rates).

1.6.1.1.5 Data Base Applicability

In general, the site specific data presented in this data base is strictly defined only in the context of this study. Because of the limitations inherent in the use of component failure data from the LERs, the data base development methodology used in this study has applied specific criteria to the synthesis of failure and success data to produce a consistent, realistic, conservative presentation of the available state of knowledge of component hardware failure rates at Indian Point Unit 3. Although the consistent application of this methodology provides a basis for comparing this data with data from the other plants analyzed in this study, such a comparison is possible only in the specific framework of this analysis and is not directly adaptable to other applications.

1.6.1.1.6 Plant Specific Component Failure Mode Data Summaries

Component Type	Failure Mode	Page
Manual Valves	Transfer closed	1.6-12
	Transfer open	1.6-13
Check Valves	Fail to open	1.6-14
	Fail to seat	1.6-15
Relief/Safety Valves	Premature opening	1.6-16
Motor-Operated Valves	Failure to operate	1.6-17
	Transfer closed	1.6-18
	Transfer open	1.6-19
Air-Operated Valves	Failure to operate	1.6-20
	Transfer closed	1.6-21
	Transfer open	1.6-22
Motor-Driven Pumps	Failure to start	1.6-23
Turbine-Driven Auxiliary Feedwater Pump	Failure to start	1.6-24
Safety Injection Pumps	Fail during operation	1.6-25

Component Type	Failure Mode	Page
Residual Heat Removal Pumps	Fail during operation	1.6-26
Component Cooling Pumps	Fail during operation	1.6-27
Auxiliary Component Cooling Pumps	Failure during operation	1.6-28
Service Water Pumps	Fail during operation	1.6-29
Recirculation Pumps	Fail during operation	1.6-30
Containment Spray Pumps	Fail during operation	1.6-31
Motor-Driven Auxiliary Feedwater Pumps	Fail during operation	1.6-32
Turbine-Driven Auxiliary Feedwater Pumps	Fail during operation	1.6-33
Containment Fan Coolers	Failure to start	1.6-34
	Fail during operation	1.6-35
Heat Exchangers	Rupture	1.6-36
	Plugged - tube side	1.6-37
	Plugged - shell side	1.6-38
Diesel Generators	Failure to start	1.6-39
	Fail during operation	1.6-40
Bus Feed Circuit Breakers	Failure to close	1.6-41
	Fail to open	1.6-42
	Transfer open	1.6-43
AC Power Transformers	Fail during operation	1.6-44
Static Inverters	Fail during operation	1.6-45
DC Power Batteries	Fail during operation	1.6-46
Battery Chargers	Fail during operation	1.6-47
Buswork	Failure during operation	1.6-48

Component Type: MANUAL VALVES

Failure Mode: Transfer Closed

- Total Component Service Hours in Period: 3.07×10^6

  Basis: Data base includes service hours for valves verified to be open by actual fluid flow through valve during periodic test or normal operation. Standby system valves remaining open between flow tests are included for the duration of the periods between tests since performance of the test would detect failure. Service hours exclude periods during which failure would not be reportable or during which actual flow verification was not required (e.g., cold shutdown periods for several systems).

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: MANUAL VALVES

Failure Mode: Transfer Open/Excessive Leakage Through Valve

- Total Component Service Hours in Period: 197

  Basis: Data base includes service hours during which valves are verified to remain closed through periodic system flow testing or normal operation, and includes only those periods during which the valves are subjected to pressure or flow conditions (e.g., valves closed for a flow test and reopened after the test is completed are included only for the duration of the flow test). Valves whose failure during normal operation would not result in reportable system degradation are excluded from the data base.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: CHECK VALVES

Failure Mode: Failure to Open on Demand

- Test Data:

  - Number of Tests Per Month: 36
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 20
  - Number of Tests Per Refueling: 15
  - Total Number of Tests in Period: 1,550

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: CHECK VALVES

Failure Mode: Failure to Seat/Excessive Reverse Leakage

- Total Component Service Hours in Period: 8.64×10^5

  Basis: Data Base includes service hours during which valves are verified to remain closed through perodic system flow testing or normal operation and includes only those periods during which the valves are subjected to pressure or flow conditions. Valves whose failure during normal operation would not result in reportable system degradation are excluded from the data base.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: RELIEF/SAFETY VALVES

Failure Mode: Premature Opening or Leakage

- Total Component Service Hours in Period: 1.60×10^5

  Basis: Data base includes service hours for valves of similar type to those in systems analyzed in this study and whose failures would be reportable under normal system operating conditions. Valve service hours during periods for which failure would not result in reportable system degradation or reportable corrective actions are excluded from the data base. The specific valves included in the data base are:

  - Accumulator Relief Valves
  - Letdown Relief Valve
  - RHR Suction Relief Valve

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
10/02/76	RHR Suction Relief Valve 1836	Unspecified

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: MOTOR-OPERATED VALVES

Failure Mode: Failure to Operate on Demand

- Test Data:

  - Number of Tests Per Month: 4
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 42
  - Total Number of Tests in Period: 244

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: MOTOR-OPERATED VALVES

Failure Mode: Transfer Closed

- Total Component Service Hours in Period: 6.32×10^5

  Basis: Data base includes service hours for valves verified to be open by actual fluid flow through valve during periodic test or normal operation. Standby system valves remaining open between flow tests are included for the duration of the intertest periods since performance of the test would detect failure. Service hours exclude periods during which failure would not be reportable or during which actual flow verification was not required (e.g., cold shutdown periods for several systems).

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: MOTOR-OPERATED VALVES

Failure Mode: Transfer Open/Excessive Leakage Through Valve

- Total Component Service Hours in Period: 290

  Basis: Data base includes service hours during which valves are verified to remain closed through periodic system flow testing or normal operation, and includes only those periods during which the valves are subjected to pressure or flow conditions (e.g., valves closed for a flow test and reopened after the test is completed are included only for the duration of the flow test). Valves whose failure during normal operation would not result in reportable system degradation are excluded from the data base.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and operating status summary

- Failure Data Source: LERs

Component Type: AIR-OPERATED VALVES

Failure Mode: Failure to Operate on Demand

- Test Data:

  - Number of Tests Per Month: 8
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 16
  - Number of Tests Per Refueling: 2
  - Total Number of Tests in Period: 388

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: AIR-OPERATED VALVES

Failure Mode: Transfer Closed (mechanical failures other than those due to air pressure variations)

- Total Component Service Hours in Period: 4.80×10^5

  Basis: Data base includes service hours for valves verified to be open by actual fluid flow through valve during periodic test or normal operation. Standby system valves remaining open between flow tests are included for the duration of the periods between tests, since performance of the test would detect failure. Service hours exclude periods during which failure would not be reportable or during which actual flow verification was not required (e.g., cold shutdown periods for several systems).

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: AIR-OPERATED VALVES

Failure Mode: Transfer Open/Excessive Leakage Through Valve (mechanical failures other than those due to air pressure variations)

- Total Component Service Hours in Period: 2.40×10^4

  Basis: Data base includes service hours during which valves are verified to remain closed through periodic system flow testing or normal operation, and includes only those periods during which the valves are subjected to pressure or flow conditions (e.g., valves closed for a flow test and reopened after the test is completed are included only for the duration of the flow test). Valves whose failure during normal operation would not result in reportable system degradation are excluded from the data base.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: MOTOR-DRIVEN PUMPS

Failure Mode: Failure to Start on Demand

- Test Data:

  - Number of Tests Per Month: 19
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 3
  - Number of Tests Per Refueling: 14
  - Total Number of Tests in Period: 800

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
04/12/77	Auxiliary Feedwater Pump 33	Pump Shaft Failure
01/12/77	Safety Injection Pump 33	Sequence Timing Relay Failure

- Test Data Source: Test Review

- Failure Data Source: LERs

Component Type: TURBINE-DRIVEN AUXILIARY FEEDWATER PUMP

Failure Mode: Failure to Start on Demand

- Test Data:

  - Number of Tests Per Month: 1
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 0
  - Total Number of Tests in Period: 40

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: SAFETY INJECTION PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 40

  Basis: Since the operation of these pumps is formally documented only during periodic operability verification tests, the pump service hours include only pump operating times during these tests. The pumps may be operated sporadically for the performance of auxiliary functions during normal plant operation, but these operating times are documented only in control room logs and were not included in this study.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
04/04/77	Safety Injection Pump 31	Worn Internals

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: RESIDUAL HEAT REMOVAL PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 8,000

  Basis: Since one residual heat removal pump is required to remain in operation during all periods of cold shutdown, and since failure of the operating pump during these periods should be reported, the data base includes the service hours for these pumps during periodic operability verification testing and cold shutdown operating periods.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
03/28/78	RHR Pump 31	Defective Seal Gasket
08/15/78	RHR Pump 32	Worn Seals and Gasket

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: COMPONENT COOLING PUMP

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 4.80×10^4

  Basis: Although the component cooling system is normally in service under all plant operating conditions, the service hours for these pumps include two pumps operating continuously during noncold shutdown periods only, since failures of these pumps would be reported only during these periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: AUXILIARY COMPONENT COOLING PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 53

  Basis: Since the operation of these pumps is formally documented only during periodic operability verification tests, the pump service hours include only pump operating times during these tests.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: SERVICE WATER PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 4.80×10^4

  Basis: Since the technical specifications apply operability criteria to only the service water pumps aligned to the nuclear service header, the service hours for these pumps include the normal condition of two pumps operating on this header during noncold shutdown periods only, since failures would be reported only during these periods of operation.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
08/31/78	Service Water Pump 35	Bearing Failure
04/05/79	Service Water Pump 34	Bearing Failure
08/03/79	Service Water Pump 36	Bearing and Shaft Wear

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: RECIRCULATION PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 2

  Basis: Since the operation of these pumps is formally documented only during periodic operability verification tests, the pump service hours include only pump operating times during these tests.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: CONTAINMENT SPRAY PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 20

  Basis: Since the operation of these pumps is formally documented only during periodic operability verification tests, the pump service hours include only pump operating times during these tests.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: MOTOR-DRIVEN AUXILIARY FEEDWATER PUMPS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 1,200

  Basis: Since the auxiliary feedwater system is normally in service during all periods of hot shutdown, the service hours for these pumps include both motor driven pumps operating during approximately one-half of the total hot shutdown period hours (due to the allocation of one pump to two steam generators). The number of hours in hot shutdown was estimated from a review of the station power history summaries.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: TURBINE-DRIVEN AUXILIARY FEEDWATER PUMP

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 600

  Basis: Since the turbine driven auxiliary feedwater pump is generally operated only during startup and shutdown transient modes (due to its steam demand), the service hours for this pump include approximately one-half of the total hot shutdown period hours. The number of hours in hot shutdown was estimated from a review of the station power history summaries.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
08/29/78	Auxiliary Feedwater Pump 32	Turbine Bearing Failure

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: CONTAINMENT FAN COOLERS

Failure Mode: Failure to Start on Demand

- Test Data:

  - Number of Tests Per Month: 0
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 5
  - Total Number of Tests in Period: 10

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test Review

- Failure Data Source: LERs

Component Type: CONTAINMENT FAN COOLERS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 4.80×10^4

  Basis: Although the fan cooler units are normally in service under all plant conditions, the service hours for these units conservatively include two fan coolers operating continuously during noncold shutdown periods only, since failures of these units would be reported only during these periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review and unit operating status summary

- Failure Data Source: LERs

Component Type: HEAT EXCHANGERS

Failure Mode: Rupture/Excessive Leakage

- Total Component Service Hours in Period: 9.60×10^4

  Basis: Data base includes service hours for the component cooling heat exchangers and both residual heat removal heat exchangers during noncold shutdown periods, since leakage or rupture of these heat exchangers would be detectable and reportable during these operating periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Unit operating status summary

- Failure Data Source: LERs

Component Type: HEAT EXCHANGERS

Failure Mode: Plugged - Tube Side

- Total Component Service Hours in Period: 4.80×10^4

  Basis: Data base includes service hours for the component cooling heat exchangers during noncold shutdown periods and one residual heat removal heat exchanger during periodic testing periods, since plugging of these heat exchangers would be detectable and reportable during these operating periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Unit operating status summary

- Failure Data Source: LERs

Component Type: HEAT EXCHANGERS

Failure Mode: Plugged - Shell Side

- Total Component Service Hours in Period: 4.80×10^4

  Basis: Data base includes service hours for the component cooling heat exchangers during noncold shutdown periods and one residual heat removal heat exchanger during periodic testing periods, since plugging of these heat exchangers would be detectable and reportable during these operating periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Unit operating status summary

- Failure Data Source: LERs

Component Type: DIESEL GENERATORS

Failure Mode: Failure to Start on Demand

- Test Data:

  - Number of Tests Per Month: 3
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 3
  - Total Number of Tests in Period: 185*

- Failure Data for Given Failure Mode:**

Date	Reported Failure	Cause
09/24/76	Diesel Generator 31	Air in Governor Oil Lines
10/21/76	Diesel Generator 31	Failure of Unit/Parallel Relay

- Test Data Source: Test review and maintenance history summary

- Failure Data Source: LERs

*Since the technical specifications require immediate and daily operability verification for the redundant diesel generators whenever one diesel generator is removed from service for maintenance, station maintenance records were reviewed to determine the number of additional diesel generator starts for these verifications through the end of 1979. Only maintenance performed during noncold shutdown periods was included in this review. Of the 185 reported tests, 126 were performed as routine periodic operability tests and 59 were performed for operability verification during or following maintenance. Although the tests performed during maintenance are documented only in the control room operating logs and do not test the ability of the diesel generator to accept or run under load, the starting capabilities of the diesel engines are tested, and failures would be reported due to the technical specifications requirements for unit shutdown if more than one diesel generator is inoperable.

**Since the data base is developed for hardware failures only, data base excludes failure of diesel generator 31 reported on 8/30/76 due to failure caused by human error. Since the only failures reported are those which would have prevented a diesel generator from starting or operating under safeguards actuation conditions, any failures which may have been observed in addition to those reported should not have contributed to diesel generator failure for the event categories analyzed in this study.

Component Type: DIESEL GENERATORS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 204

  Basis: Since the diesel generators are normally operated under load only during the routine periodic operability verification tests, the service hours include only operating time during these testing periods. Tests performed for redundant diesel generator operability verification during maintenance periods do not include operation of the diesel generators under load and are, therefore, excluded from this data base. Routine operation of the diesel generators during unit startup and shutdown is similarly performed in an unloaded state, and is also excluded from these service hours.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

Component Type: BUS FEED CIRCUIT BREAKERS

Failure Mode: Failure to Close on Demand

- Test Data:

  - Number of Tests Per Month: 3
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 11
  - Total Number of Tests in Period: 142*

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
06/11/76	Diesel Generator Feed to Bus 6A	Spurious Operation of Auxiliary Contacts

- Test Data Source: Test review

- Failure Data Source: LERs

*Data base includes only the operations of the diesel generator bus feed circuit breakers verified during routine periodic tests. Circuit breakers supplying power to individual components (e.g., 480V pumps) are not included in this data base, since the failures of these breakers are included in the specific component failure data bases. Operations of circuit breakers associated with routine unit startup and shutdown operations are not included.

Component Type: BUS FEED CIRCUIT BREAKERS

Failure Mode: Failure to Open on Demand

- Test Data:

  - Number of Tests Per Month: 3
  - Number of Tests Per Quarter: 0
  - Number of Tests Per Year: 0
  - Number of Tests Per Refueling: 11
  - Total Number of Tests in Period: 142*

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: Test review

- Failure Data Source: LERs

*Data base includes only the operations of the diesel generator bus feed circuit breakers verified during routine periodic tests. Circuit breakers supplying power to individual components (e.g., 480V pumps) are not included in this data base, since the failures of these breakers are included in the specific component failure data bases. Operations of circuit breakers associated with routine unit startup and shutdown operations are not included.

Component Type: BUS FEED CIRCUIT BREAKERS

Failure Mode: Transfer Open

- Total Component Service Hours in Period: 2.88×10^5

  Basis: Data base includes service hours for the bus feed breakers during noncold shutdown periods only, since failures of these breakers would affect offsite power supply to the 480V essential power buses and would be reported under these operating conditions. Circuit breakers supplying power to individual components (e.g., 480V pumps) are not included in this data base, since the failures of these breakers are included in the specific component failure data bases. The breakers included in this data base are: 6.9 kV breakers ST5, ST6, (UT2 and UT2/ST5)*, (UT3 and UT3/ST6)*; and 480V breakers SS5, SS2, SS3, SS6, 5A, 2A, 3A, and 6A.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
05/18/76	Feed Breaker to Bus 6A	Spurious Operation of Bus 6A Lockout Relay

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

*One of these breakers must be closed during all modes of unit operation

Component Type: AC POWER TRANSFORMERS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 1.28×10^5

  Basis: Data base includes service hours for the following transformers during noncold shutdown periods only, since failures of these transformers would affect offsite power supply to the 480V essential power buses and would be reported under these operating conditions. The transformers included in this data base are the station auxiliary transformer and the 6.9 kV/480V station service transformers SST5, SST2, SST3, and SST6.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: STATIC INVERTERS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 7.20×10^4

  Basis: Data base includes instrument bus inverter service hours during noncold shutdown operating periods only, since failures of these components would be reported only during these periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: DC POWER BATTERIES

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 7.20×10^4

  Basis: Data base includes battery service hours during noncold shutdown operating periods only, since failures would be reported only during these periods.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: BATTERY CHARGERS

Failure Mode: Fail During Operation

- Total Component Service Hours in Period: 7.20×10^4

  Basis: Data base includes battery charger service hours during noncold shutdown operating periods only, since failures would be reported only during these periods.

- Failure Data for Given Failure Mode:

Date	Reported Failure	Cause
05/10/76	One Battery Charger (Unidentified)	Cooling Fan Tripped
06/08/76	Battery Charger 31	Failure of Pressure Sensor

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

Component Type: BUSWORK

Failure Mode: Catastrophic Failure During Operation

- Total Component Service Hours in Period: 5.45×10^5

  Basis: The failure mode considered in this data base would result in complete failure of an electric power supply bus (i.e., failures more violent than transient short circuits or individual circuits failing open) and as such, should be reported during all unit operating modes. Using this criterion, the data base includes service hours for the following buses under all unit operating conditions: 6.9 kV buses 5, 2, 3, and 6; 480V buses 5A, 2A, 3A, and 6A; motor control centers 36A and 36B; instrument buses 31, 32, 33, and 34; DC power panels 31, 32, and 33.

- Failure Data for Given Failure Mode: No failures reported

- Test Data Source: System drawings and unit operating status summary

- Failure Data Source: LERs

TABLE 1.6.1-1

INDIAN POINT 3 COLD SHUTDOWN PERIODS (1976-1979)

Date		Reason for Shutdown
1976:	01/01 - 04/25	Prior to Initial Startup
	05/15 - 05/24	Feedwater Pump Repair
	06/11 - 06/15	Trip Testing
	06/26 - 06/28	Transformer Repair
	06/30 - 07/05	Transformer Repair
	07/24 - 07/26	Heater Drain Pumps
	09/10 - 10/03	Maintenance Outage
1977:	01/15 - 01/26	Pressurizer Spray Valve Leak
	10/06 - 12/15	Turbine Maintenance Outage
1978:	02/03 - 02/09	RTD Manifold Valve Leaks
	06/08 - 08/18	Refueling Outage
	12/07 - 12/14	Steam Generator Tube Leak
1979:	03/19 - 03/27	Steam Generator Tube Leak
	09/14 - 12/31	Refueling Outage

TABLE 1.6.1-2

INDIAN POINT 3 COMPONENT PERIODIC TESTS (1976-1979)

Testing Frequency	Number of Tests Performed in Study Period
Monthly*	40
Quarterly**	14
Annually	4
Refueling	2

*During power operation
**During any calendar quarter in which the unit was not in continuous cold shutdown.

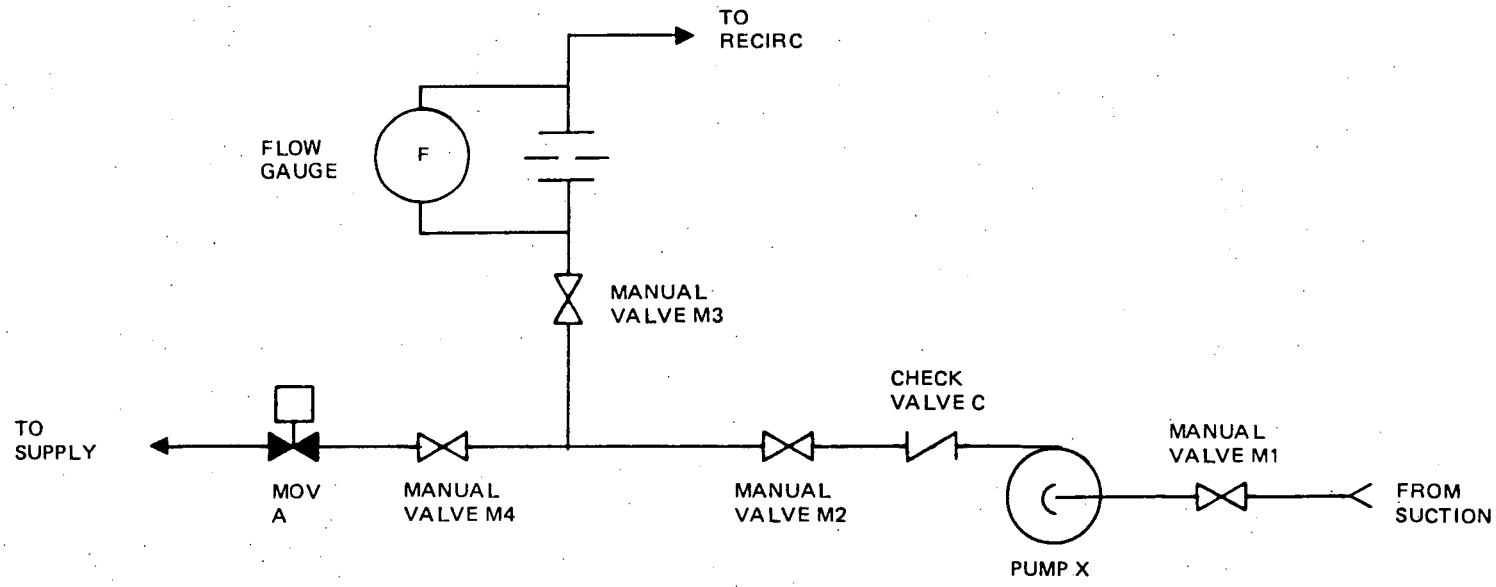


Figure 1.6.1-1. Indian Point 3 Flow Test Data Example System

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1.6.1.2 Generic and Updated Component Failure Data

This appendix discusses the generic data, references their sources and shows the updated plant data, specialized using Bayes' theorem.

The derivation of prior distributions for the failure rates involves an extensive literature survey and the use of judgment. Table 1.6.1-3 identifies some of the key sources. For many components a single source does not exist which has all the data required for this study in a form that would allow an unambiguous determination of the prior distribution. For example, it is not always specified what failure modes are represented, the environments for which the data are applicable, etc.

Most of the generic data on valves, pumps and diesel generators were obtained from the NUREG data summaries (References 1.6.1-1, 1.6.1-2, and 1.6.1-3). Generic data for heat exchangers were obtained from NPRDS (Reference 1.6.1-4). This study used the mean values reported in the NUREGs as the mean values of the generic population and the ratio of the 95th to the 5th percentile reported in the Reactor Safety Study (Reference 1.6.1-5) as the ratio of the 80th to the 20th percentiles of the population variability curves. The lognormal curves from the RSS are regarded as the results of experiments on populations. They are frequency distributions that represent the variability stemming from different manufacturers, different models, different operating and maintenance conditions, and the random fluctuations occurring in presumably identical components. For example, if a large population of valves, pumps, or diesel generators were tested and if the frequency of specific failures were plotted, that plot would turn out to be a lognormal curve.

Data for electronic, electrical, and sensing components were obtained from IEEE STD-500 (Reference 1.6.1-6). The reported values were mainly synthesized from the opinions of approximately 200 experts (a form of the Delphi procedure was used). Each expert reported a low, recommended, and high value of the failure rate under normal conditions and a maximum value which would be applicable under all conditions (including abnormal ones). The estimates were pooled using geometric averaging techniques, e.g.,

$$\hat{\lambda}_{MAX} = \left[\prod_{i=1}^{n} \hat{\lambda}_{MAX,i} \right]^{1/n} \qquad (1.6.1\text{-}1)$$

This method of averaging was judged to be a better representation of the expert estimates, which were often given in terms of negative powers of 10. In effect, the usual arithmetic averages of the exponents were used.

The IEEE STD-500 does not recommend a distribution. The method of averaging, however, indicates that it would be appropriate to assume a lognormal distribution. For this analysis, the "recommended" value was used as the median and the "maximum" value as the 80th percentile of the population variability curve. These two values were then used to generate the 20th percentile.

In some cases for which there was no applicable data in the NUREGs or in IEEE STD-500, the RSS 5th and 95th percentile values were used as the 20th and 80th percentiles of the population variability curve.

The historical plant specific data listed in Section 1.6.1 for the number of failures and the number of demands or total service time was updated using generic prior distributions to obtain a specialized posterior distribution. The methodology for performing this specialization is discussed in the main report. The results are listed in Table 1.6.1-4, which contains the following information:

- Component description and failure mode.
- Plant evidence (historical plant data).
- Updated plant data (failure rate means and variances for posterior distribution).
- Generic prior distribution used to update the plant evidence and the sources of the generic data.

TABLE 1.6.1-3

INDIAN POINT 3 KEY GENERIC RELIABILITY DATA SOURCES

Item	Key Data Sources	Reference
Electrical	IEEE STD-500	1.6.1-6
Electronic	IEEE STD-500	1.6.1-6
Instruments	WASH-1400, IEEE STD-500	1.6.1-5, 1.6.1-6
Valves	NUREG/CR-1363, WASH-1400	1.6.1-1, 1.6.1-5
Pumps	NUREG/CR-1205, WASH-1400	1.6.1-2, 1.6.1-5
Diesel Generators	NUREG/CR-1362, WASH-1400	1.6.1-3, 1.6.1-5
Mechanical	NPRDS, WASH-1400	1.6.1-4, 1.6.1-5

TABLE 1.6.1-4

INDIAN POINT 3 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
1) System: All Component Type: Manual Valves, Motor-Operated Valves Failure Mode: Transfer Closed	0	3.7(6) hours	9.15(-8) /hour	1.01(-14) /(hour)^2	[2.8(-8)] /hour	[2.8(-7)] /hour	W-1400. Fail to remain open. Plugged. λ5 = 3(-5)/demand λ95 = 3(-4)/demand used 1 demand/ 45 days to convert to hours. λ5 = 2.8(-8)/hour; λ95 = 2.8(-7)/hour.
2) System: All Component Type: Manual Valves Failure Mode: Transfer Open/Excessive Leakage Through Valve	0	1.97(2) hours	2.00(-8) /hour	1.89(-13) /(hour)^2	2.0(-8) /hour	100	N-1363. Manual valves. External leakage. PWRs $\bar{X}$ = 2(-8)/hour. W-1400. MOVs. External leakage/ rupture. λ5 = 1(-9)/hour; λ95 = 1(-7)/hour.
3) System: All Component Type: Check Valves Failure Mode: Failure to Open on Demand	0	1.55(3) demands	6.91(-5) /demand	1.03(-8) /(demand)^2	1.0(-4) /demand	10	N-1363. Check valves. Fail to open PWRs $\bar{X}$ = 1(-4)/demand. W-1400. Check valves. Failure to open. λ5 - 3(-5)/demand; λ95 = 3(-4)/demand.
4) System: All Component Type: Check Valves Failure Mode: Failure to Seat/ Excessive Reverse Leakage	0	8.64(5) hours	2.58(-7) /hour	1.00(-13) /(hour)^2	5.0(-7) /hour	10	N-1363. Check valves. Internal leakage. PWRs $\bar{X}$ = 5(-7)/hour. W-1400. Check valves. Reverse leak. λ5 = 1(-7)/hour; λ95 = 1(-6)/hour.
5) System: All Component Type: Relief/Safety Valves Failure Mode: Premature Opening or Leakage	1	1.60(5) hours	3.66(-6) /hour	1.28(-11) /(hour)^2	3.0(-6) /hour	10	N-1363. PWR safety valves. Premature opening. $\bar{X}$ = 3(-6)/hour. W-1400. Relief valves (all Rx types). Premature opening. λ5 = 3(-6)/hour; λ95 = 3(-5)/hour.
6) System: All Component Type: Motor-Operated Valves Failure Mode: Failure to Operate on Demand	0	2.44(2) demands	1.51(-3) /demand	2.64(-6) /(demand)^2	4.0(-3) /demand	10	N-1363. PWR - Remote operated plus MOV. No command faults. Fail to operate. $\bar{X}$ = 4(-3)/demand. W-1400. Failed to operate. λ5 = 3(-4)/demand; λ95 = 3(-3)/demand.

NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.6.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.6.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.6.1-3)

NPRDS: 1976, page 34 (Reference 1.6.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.6.1-5)
IEEE 500: 1977 (Reference 1.6.1-6)

TABLE 1.6.1-4 (continued)

INDIAN POINT 3 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
7) System: All Component Type: Motor-Operated Valves Failure Mode: Transfer Open/Excessive Leakage Through Valve	0	2.90(2) hours	9.87(-8) /hour	4.38(-12) /(hour)^2	1.0(-7) /hour	100	N-1363. PWR Remote + MOV - No command fault. External leakage. $\bar{X}$ = 1(-7)/hour. W-1400. MOVs External leakage/ rupture. λ5 = 1(-9)/hour; λ95 = 1(-7)/hour.
8) System: All Component Type: Air-Operated Valves Failure Mode: Failure to Operate on Demand	0	3.88(2) demands	4.98(-4) /demand	4.03(-7) /(demand)^2	9.0(-4) /demand	10	N-1363. PWR AOV Fail to operate. No commmand faults. X = 9(-4)/demand. W-1400. AOV Fails to operate λ5 = 1(-4)/demand; λ95 = 1(-3)/demand.
9) System: All Component Type: Air-Operated Valves Failure Mode: Transfer Closed	0	4.8(5) hours	1.69(-7) /hour	6.90(-14) /(hour)^2	[2.8(-8)] /hour	[2.8(-7)] /hour	W-1400. AOV Plug. Failure to remain open. Used 1 demand/ 45 days to convert to hours. λ5 = 3(-5) = 2.8(-8)/hour; λ95 = 3(-4) = 2.8(-7)/hour.
10) System: All Component Type: Air-Operated Valves Failure Mode: Transfer Open, Excessive Leakage	0	2.4(4) hours	7.70(-8) /hour	3.47(-13) /(hour)^2	1.0(-7) /hour	100	N-1363. AOV External leakage X = 1(-7)/hour. W-1400. AOV External leakage/rupture. λ5 = 1(-9)/hour; λ95 = 1(-7)/hour.
11) System: All Component Type: Pumps - Motor-Driven Failure Mode: Failure to Start on Demand	2	8.0(2) demands	1.36(-3) /demand	1.22(-6) /(demand)^2	5.0(-4) /demand	10	N-1205. Standby system. Does not start. No command faults. $\bar{X}$ = 5(-4)/demand. W-1400. Electric motor. Failure to start. λ5 = 1(-4)/demand; λ95 = 1(-3)/demand.
12) System: Auxiliary Feedwater Component Type: Turbine-Driven Auxiliary Feedwater Pump Failure Mode: Failure to Start on Demand	0	4.0(1) demands	1.65(-3) /demand	1.03(-5) /(demand)^2	4.0(-3) /demand	100 /demand	N-1205. Standby system. No command faults. Does not start. $\bar{X}$ = 4(-3)/demand. λ80/λ20 based on engineering judgment.

NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.6.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.6.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.6.1-3)
NPRDS: 1976, page 34 (Reference 1.6.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.6.1-5)
IEEE 500: 1977 (Reference 1.6.1-6)

TABLE 1.6.1-4 (continued)

INDIAN POINT 3 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
13) System: Safety Injection Component Type: Safety Injection Pumps Failure Mode: Fail During Operation	1	4.0(1) hours	1.79(-3) /hour	4.77(-5) /(hour)^2	2.0(-5) /hour	100	N-1205. Alternating System. Does not operate given start. $\bar{X}$ = 2(-5)/hour. W-1400 pump (w/o motor). Failure to run. λ5 = 3(-6)/hour; λ95 = 3(-4)/hour.
14) System: Residual Heat Removal Component Type: Residual Heat Removal Pumps Failure Mode: Fail During Operation	2	8.0(3) hours	1.50(-4) /hour	1.74(-8) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
15) System: Component Cooling Component Type: Component Cooling Pumps Failure Mode: Fail During Operation	0	4.8(4) hours	3.26(-6) /hour	2.47(-11) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
16) System: Component Cooling Component Type: Auxiliary Component Cooling Pumps Failure Mode: Fail During Operation	0	5.3(1) hours	1.65(-5) /hour	2.22(-8) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
17) System: Service Water Component Type: Service Water Pumps Failure Mode: Fail During Operation	3	4.8(4) hours	4.68(-5) /hour	1.07(-9) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
18) System: Recirculation Component Type: Recirculation Pumps Failure Mode: Fail During Operation	0	2.0 hours	1.96(-5) /hour	1.70(-7) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
19) System: Containment Spray Component Type: Containment Spray Pumps Failure Mode: Fail During Operation	0	2.0(1) hours	1.77(-5) /hour	6.44(-8) /(hour)^2	2.0(-5) /hour	100	Same as Number 13
20) System: Auxiliary Feedwater Component Type: Motor-Driven Auxiliary Feedwater Pumps Failure Mode: Fail During Operation	0	1.2(3) hours	9.99(-6) /hour	1.98(-9) /(hour)^2	2.0(-5) /hour	100	Same as Number 13

NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.6.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.6.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.6.1-3)
NPRDS: 1976, page 34 (Reference 1.6.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.6.1-5)
IEEE 500: 1977 (Reference 1.6.1-6)

TABLE 1.6.1-4 (continued)

INDIAN POINT 3 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
21) System: Auxiliary Feedwater Component Type: Turbine-Driven Auxiliary Feedwater Pump Failure Mode: Fail During Operation	1	6.0(2) hours	3.77(-4) /hour	5.30(-7) /(hour)^2	2.0(-5) /hour	100	Same as Number 13. Turbine-driven pump failure during operation similar to motor-driven pump during operation.
22) System: Containment Fan Coolers Component Type: Containment Fan Coolers Failure Mode: Failure to Start on Demand	0	1.0(1) demands	7.80(-4) /demand	2.56(-6) /(demand)^2	[1.0(-4)] /demand	[1.0(-3)] /demand	W-1400. Electric motor. Failure to start. λ5 = 1(-4)/demand; λ95 = 1(-3)/demand.
23) System: Containment Fan Coolers Component Type: Containment Fan Coolers Failure Mode: Fail During Operation	0	4.8(4) hours	9.79(-6) /hour	2.23(-10) /(hour)^2	[1.0(-4)] /hour	[1.0(-2)] /hour	W-1400. Electric motor. Failure to run. Extreme environment. λ5 = 1(-4)/hour; λ95 = 1(-2)/hour.
24) System: All Component Type: Heat Exchangers Failure Mode: Rupture/Excessive Leakage	0	9.6(4) hours	9.73(-7) /hour	3.34(-12) /(hour)^2	4.56(-6) /hour	100	NPRDS page 34. $\bar{X}$ = 4.56(-6)/hour. λ80/λ20 based on engineering judgment.
25) System: All Component Type: Heat Exchangers Failure Mode: Plugged (Tube Side)	0	4.80(4) hours	ε	ε	ε	ε	Negligibly small failure rate. Estimated on the basis of engineering judgment.
26) System: All Component Type: Heat Exchangers Failure Mode: Plugged (Shell Side)	0	4.80(4) hours	ε	ε	ε	ε	Negligibly small failure rate. Estimated on the basis of engineering judgment.
27) System: Diesel Generators Component Type: Diesel Generators Failure Mode: Failure to Start on Demand	2	1.85(2) demands	1.44(-2) /demand	5.12(-5) /(demand)^2	3.0(-2) /demand	10	N-1362. Monthly testing. Diesel generator fails to start. No command faults. $\bar{X}$ = 3(-2)/demand. W-1400. Diesel generator. Failure to start. λ5 = 1(-2)/demand; λ95 = 1(-1)/demand.

NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.6.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.6.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.6.1-3)
NPRDS: 1976, page 34 (Reference 1.6.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.6.1-5)
IEEE 500: 1977 (Reference 1.6.1-6)

TABLE 1.6.1-4 (continued)

INDIAN POINT 3 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
28) System: Diesel Generators Component Type: Diesel Generators Failure Mode: Fail During Operation	0	2.04(2) hours	9.37(-4) /hour	3.37(-6) /(hour)^2	2.0(-2) /hour	100	N-1362. Monthly testing. Diesel generator. Does not continue to run. No command faults. $\bar{X}$ = 2(-2)/hour. W-1400. Diesel generator. Failure to run. λ5 = 3(-4)/hour; λ95 = 3(-2)/hour.
29) System: AC Electric Power Component Type: Bus Feed Breakers Failure Mode: Failure to Close on Demand	1	1.42(2) demands	1.33(-3) /demand	5.57(-6) /(demand)^2	[1.0(-7)] /demand	[1.0(-5)] /demand	IEEE-500. Interior design. AC breaker fails to close. Page 148. Rec = 1(-6)/demand; Max = 1(-5)/demand.
30) System: AC Electric Power Component Type: Bus Feed Breakers Failure Mode: Failure to Open on Demand	0	1.42(2) demands	1.45(-3) /demand	1.12(-5) /(demand)^2	[2.27(-5)] /demand	[2.27(-3)] /demand	IEEE-500. Interior design. AC breaker fails to open. Page 148. Rec = 2.27(-4)/demand; Max = 2.27(-3)/demand
31) System: AC Electric Power Component Type: Bus Feed Breakers Failure Mode: Transfer Open	1	2.88(5) hours	2.67(-6) /hour	3.21(-12) /(hour)^2	[3.08(-9)] /hour	[6.0(-7)] /hour	IEEE-500. Interior design. AC breaker spurious operation. Page 148. Rec = 4.3(-8)/hour; Max = 6(-7)/hour.
32) System: AC Electric Power Component Type: Transformers; Dry Type-Three Phase Failure Mode: Fail During Operation	0	1.28(5) hours	8.39(-7) /hour	1.57(-12) /(hour)^2	[1.44(-7)] /hour	[1.51(-6)] /hour	IEEE-500. Transformers (601V-15kV). All modes. Page 300. Rec = 4.67(-7)/hour; Max = 1.51(-6)/hour.
33) System: AC Electric Power Component Type: Inverters Failure Mode: Fail During Operation	0	7.2(4) hours	3.77(-6) /hour	6.92(-11) /(hour)^2	[3(-7)] /hour	[3.0(-5)] /hour	W-1400. Solid state device. High power application. Fails to function. λ5 = 3(-7)/hour; λ95 = 3(-5)/hour.

NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.6.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.6.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.6.1-3)
NPRDS: 1976, page 34 (Reference 1.6.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.6.1-5)
IEEE 500: 1977 (Reference 1.6.1-6)

TABLE 1.6.1-4 (continued)

INDIAN POINT 3 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
34) System: DC Electric Power Component Type: Batteries Failure Mode: Fail During Operation	0	7.2(4) hours	8.35(-8) /hour	6.44(-14) /(hour)^2	[4.95(-9)] /hour	[8.74(-8)] /hour	IEEE-500. Batteries-lead-acid. Page 104. Stationary types for float service. Catastrophic failure. Rec = 2.08(-8)/hour; Max = 8.74(-8)/hour.
35) System: DC Electric Power Component Type: Battery Chargers Failure Mode: Fail During Operation	2	7.2(4) hours	1.35(-5) /hour	2.55(-13) /(hour)^2	[1.78(-8)] /hour	[1.25(-4)] /hour	IEEE-500. Rectifiers. Stationary type. All modes. Page 90. Rec = 1.49(-6)/hour; Max = 1.25(-4)/hour.
36) System: Safeguards Actuation Component Type: Fuse, DC Power Failure Mode: Opens Prematurely	*	*	8.32(-7) /hour	1.08(-9) /(hour)^2	[2.15(-9)] /hour	[2.05(-7)] /hour	IEEE-500. Fuse. DC power. Opens prematurely. Page 193. Rec = 2.1(-8)/hour; Max = 2.05(-7)/hour.
37) System: Safeguards Actuation Component Type: Master Relay Latch and Reset Coil Included Failure Mode: Fails to Energize on Demand	*	*	1.15(-5) /demand	3.38(-9) /(demand)^2	[4.92(-7)] /demand	[1.03(-5)] /demand	IEEE-500. Relay. Fails to close. Page 154. Rec = 2.25(-6)/demand; Max = 1.03(-5)/demand.
38) System: Safeguards Actuation Component Type: Relay-General Failure Mode: Contacts Open	*	*	2.43(-7) /hour	3.26(-13) /(hour)^2	[3.0(-8)] /hour	[3.0(-7)] /hour	W-1400. Relay. Normally closed contacts open. λ5 = 3(-8)/hour; λ95 = 3(-7)/hour.
39) System: Safeguards Actuation Component Type: Bistable Switch Failure Mode: Failure to Open on Demand	*	*	3.88(-7) /demand	1.47(-13) /(demand)^2	[1.38(-7)] /demand	[5.52(-7)] /demand	IEEE-500. Bistable switch. Failed to function when signaled. Page 483. Rec = 2.76(-7)/demand; Max = 5.52(-7)/demand.
40) System: Safeguards Actuation Component Type: Transmitters Failure Mode: Fail to Provide Proper Output	*	*	1.66(-6) /hour	6.28(-12) /(hour)^2	[λ50] 9.18(-7) /hour	[RF] 6	IEEE-500. Transmitter. Catastrophic failure. Page 428. Rec = 9.18(-7)/hour; RF = 6 = $\sqrt{max/low}$.

*Generic data was used to calculate the mean and variance. No plant data was used.

NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.6.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.6.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.6.1-3)
NPRDS: 1976, page 34 (Reference 1.6.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.6.1-5)
IEEE 500: 1977 (Reference 1.6.1-6)

TABLE 1.6.1-4 (continued)

INDIAN POINT 3 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated Mean	Updated Variance	Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
41) System: Safeguards Actuation Component Type: Switches Failure Mode: Contacts Short Across	*	*	4.28(-7) /hour	3.36(-10) /(hour)^2	[1.0(-9)] /hour	[1.0(-7)] /hour	W-1400. Switches. Contacts short across. λ5 = 1(-9)/hour; λ95 = 1(-7)/hour.
42) System: All Electric Power Component Type: Bus, Metal-Enclosed Failure Mode: Open Circuit	0	5.45(5) /hours	3.25(-8) /hour	1.27(-14) /(hour)^2	[6.44(-10)] /hour	[2.74(-8)] /hour	IEEE-500. Metal enclosed bus. Open circuit. Page 188. Rec = 4.2(-9)/hour; Maximum = 2.74(-8)/hour.
43) System: All Electric Power Component Type: Manual Transfer Devices (Switches) Failure Mode: Transfer Open	*	*	ε	ε	ε	ε	Negligibly small failure rate. Estimated on the basis of engineering judgment.
44) System: Reactor Protection Component Type: Control Cable Failure Mode: Line-to-Line Short	*	*	3.22(-6) /hour	8.96(-11) /(hour)^2	[2.93(-7)] /hour	[3.68(-6)] /hour	IEEE-500. Copper conductor. Line-to-line short. Page 524. Rec = 1.038(-6)/hour; Maximum = 3.675(-6)/hour.
45) System: Reactor Protection Component Type: Control Cable Failure Mode: Line-to-Ground Short	*	*	7.52(-6) /hour	4.88(-10) /(hour)^2	[6.84(-7)] /hour	[8.58(-6)] /hour	IEEE-500. Copper conductor. Line-to-ground short. Page 524. Rec = 2.422(-6)/hour; Maximum = 8.575(-6)/hour.
46) System: All Electric Power Component Type: Trip Relay Failure Mode: Fails to Open on Demand	*	*	6.28(-6) /demand	2.49(-11) /(demand)^2	[2.73(-6)] /demand	[8.85(-6)] /demand	IEEE-500. Auxiliary relays. Fail to open. Page 164. Rec = Not given. An RF = $\sqrt{10}$ was used based on W-1400. Maximum = 8.85(-6)/demand.
47) System: All Pipes (>3" In Diameter) Component Type: Pipe Section Failure Mode: Ruptures/Plugs	*	*	8.60(-9) /hour	6.00(-15) /(hour)^2	[λ5] 3.0(-11) /hour	[λ95] 3.0(-8) /hour	W-1400. Pipes (>3 inches) High quality section as defined in W-1400. λ5 = 3(-11)/hour; λ95 = 3(-8)/hour.

*Generic data was used to calculate the mean and variance. No plant data was used.
NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.6.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.6.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.6.1-3)
NPRDS: 1976, page 34 (Reference 1.6.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.6.1-5)
IEEE 500: 1977 (Reference 1.6.1-6)

TABLE 1.6.1-4 (continued)

INDIAN POINT 3 SPECIALIZED COMPONENT HARDWARE FAILURE DATA

Component Description and Failure Mode	Plant Specific				Generic		
	Number of Failures	Service Hours or Demands	Updated		Mean [λ20]	λ80/λ20 [λ80]	Comments - Data Sources
			Mean	Variance			
48) System: All Pipes (<3" In Diameter) Component Type: Pipe Section Failure Mode: Ruptures/Plugs	*	*	8.60(-10) /hour	6.00(-17) /(hour)^2	[λ5] 3.0(-12) /hour	[λ95] 3.0(-9) /hour	W-1400. Pipes (<3 inches) High quality section as defined in W-1400. λ5 = 3(-12)/hour; λ95 = 3(-9)/hour.
49) System: Auxiliary Feedwater Component Type: Condensate Storage Tank Failure Mode: Does Not Supply Water	*	*	8.48(-10) /hour	5.10(-17) /(hour)^2	[50] 1.0(-10) /hour	[RF] 30	W-1400. Fault tree event PTKCONDF, Table II 5-5, Page II-207. λ50 = 1(-10)/hour; RF = 30.
50) System: Reactor Protection Component Type: Breakers Failure Mode: Fail to Open on Demand	0	144 demands	1.17(-3) /demand	8.86(-5) /(demand)^2	[2.97(-5)] /hour	[2.97(-3)] /hour	IEEE-500. Indoor design. AC breakers. Catastrophic failure. Page 148. Received = 2.97(-4)/demand; Maximum = 2.97(-3)/demand.

*Generic data was used to calculate the mean and variance. No plant data was used.

NOTE: 1.23(4) indicates 1.23 x 10^4

N-1363: NUREG/CR-1363, Table 23, page 63 (Reference 1.6.1-1)
N-1205: NUREG/CR-1205, Table 14, page 35 (Reference 1.6.1-2)
N-1362: NUREG/CR-1362, Table 20, page 51 (Reference 1.6.1-3)
NPRDS: 1976, page 34 (Reference 1.6.1-4)
W-1400: WASH-1400, Table III 2-1 (Reference 1.6.1-5)
IEEE 500: 1977 (Reference 1.6.1-6)

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1.6.1.3 Generic and Updated Component Maintenance Data

Maintenance activities which remove components from service and alter the normal configurations of mechanical systems can provide a significant contribution to the overall unavailability of those systems. Although plant operating and maintenance records provide a source of detailed information for specific maintenance events, a review of these records indicates that the site specific information alone provides a relatively small and inconclusive data base, for many of the standby safeguards equipment systems of specific concern in this study. As an extension of the general methodology discussed in Section 1.6.1 for component failure data, the techniques of Bayesian specialization were applied to the available site specific component maintenance data. This was done to develop a more meaningful representation of the state of maintenance at Indian Point Unit 3 than would be available from either the site specific or generic information alone.

1.6.1.3.1 Data Base Development Methodology

1.6.1.3.1.1 Data Base Definition.

1.6.1.3.1.1.1 General Considerations. The only maintenance activities included in this data base are those performed during noncold shutdown periods which place a system in a degraded condition with respect to the performance of safeguards functions analyzed in this study. Only noncold shutdown (i.e., power operation or hot shutdown) periods are included for the following reasons:

- Operating, maintenance, and system testing procedures and practices are modified significantly when the plant enters the cold shutdown condition.
- The technical specifications operability criteria for safety systems and components generally specify cold shutdown as the condition in which inoperability restrictions do not apply.
- The plant operating modes of primary concern in this study are power operation and, in some cases, hot shutdown (i.e., noncold shutdown modes).
- Specific plant shutdown and startup times were most readily available for periods when the plant was placed in cold shutdown.

Each maintenance event was analyzed for its effects on system operability by examining the restrictions or abnormal configurations of the system during the maintenance. For example, a given maintenance event which required that a pump be either mechanically or electrically isolated was included in the data base because the pump was not available for service. However, an event during which only the motor operator for a valve was deenergized, with the valve remaining in the required position for safeguards actuation, was not included because the activity resulted in no impairment of the valve's ability to permit flow under emergency conditions (the activity would have been included if the valve had been deenergized in the nonsafeguards position).

In general, maintenance performed on valves has not been included as a distinct category within this data base. The most common forms of valve maintenance performed during noncold shutdown periods are packing adjustment and repairs of the control circuitry and valve operators for motor-operated and air-operated valves. Nearly all these maintenance activities are performed with the associated valve remaining in its safeguards position and are thus nonapplicable to this data base. Because of the time criteria for unit shutdown imposed by the plant's technical specifications, major valve maintenance involving full packing replacement or repairs of the valve body and internals is generally postponed, if possible, until the unit is placed in the cold shutdown condition either for refueling or for a planned maintenance outage. Repairs which cannot be postponed until a planned shutdown and which affect the operability of an entire system require the unit to be shut down. Therefore, they are also excluded from this data base (the maintenance event records reviewed at Indian Point 3 fully support these general practices with respect to individual valve maintenance events). Maintenance on valves which affect only portions of a safety system may be performed during noncold shutdown periods within the component and system inoperability limitations imposed by the plant's technical specifications. In the majority of these cases, however, the maintenance activity requires the removal from service of the pump in the flow path of which the valve is a part (e.g., for pump suction protection or for personnel protection at the pump's discharge) and is thus indistinguishable in application from maintenance performed on the pump itself. Although valve repairs generally require less time to complete than pump repairs, the infrequent nature of individual valve maintenance and the inability to precisely differentiate between maintenance events for pumps and valves in the site specific data records justify the inclusion of valve maintenance with the associated pump maintenance data base. Therefore, in this study, maintenance performed on a "pump" is defined as any maintenance performed on any component in the unique flow path of that pump which requires removing the pump from service. Individual valve maintenance events are not considered as a distinct category.

Most of the maintenance on the plant's electric power system, with the exception of the diesel generators, is performed during cold shutdown periods when the electrical load on the system is reduced and the technical specifications inoperability criteria are relaxed. Most of the maintenance during noncold shutdown periods is performed on individual bus circuit breakers. During these infrequent events, a spare circuit breaker is installed in the maintained breaker's cubicle thereby maintaining the operability of the affected power supply and excluding this type of maintenance from the data base. Maintenance performed on other components of the electric power system is similarly excluded from the data base because of the extremely infrequent nature of these events, the operability restrictions imposed by the technical specifications, and the ability to maintain the associated power supply buses energized through redundant supply circuits and manual bus interconnections.

Based on these criteria, the component maintenance data base for Indian Point Unit 3 was developed only for noncold shutdown periods and applies only to the diesel generators and the specific pumps (and components in their associated flow paths) analyzed in this study.

1.6.1.3.1.1.2 Frequency of Maintenance. The frequency at which maintenance is performed on a given component during noncold shutdown periods generally depends on three major factors:

1. The normal service duty of the component and its associated failure rate necessitates unscheduled maintenance events for the repair of gross failures or major component degradation.

2. Regularly scheduled plant preventive maintenance and inspection programs may be instituted for certain components.

3. The duration of component inoperability allowed by the plant's technical specifications affects the frequency of maintenance.

The precise impact of the technical specifications on maintenance frequency is highly dependent on the way in which the plant's maintenance personnel compensate for the imposed time limitations and may vary widely between plants. A relatively short inoperability limit (24 hours, for example) may result in either a relatively high frequency of very short duration events during which maintenance personnel perform very minor repairs and preventive maintenance, or a low frequency of maintenance determined by the component's failure rate under conditions of minimal preventive maintenance. In the first case, plant personnel try to avoid events of long duration by scheduling many controlled events of shorter duration. In the second case, personnel are willing to accept infrequent failures requiring unit shutdown to avoid frequent events during which the possibility of imposed shutdown exists because of unforeseen delays. Whether the first or the second (or some intermediate) case prevails at a given plant depends on that plant's general operating and maintenance practices and, thus, cannot be easily generalized.

1.6.1.3.1.1.3 Duration of Maintenance. As applied in this data base, the duration of a maintenance event includes the entire time during which the affected component is unavailable for operation. This period is defined from the time when the component is originally isolated or otherwise removed from service to the time when the component is returned to service in an operable state. In many cases, it may be only weakly dependent on the actual time required for maintenance personnel to make the repairs. Thus, the duration of a maintenance event performed during noncold shutdown periods generally depends on four major factors:

1. The magnitude of the failure determines the minimum time required for maintenance personnel to make repairs and may affect the complexity and duration of the tagout time and return to service operations.

2. The availability of maintenance personnel affects the time between component failure and initiation of repairs and also affects the duration of the repair job (e.g., if maintenance personnel are regularly available from 7:00 a.m. until 11:00 p.m., repairs cannot be quickly initiated during the 8-hour offshift).

3. General plant maintenance scheduling and priorities influence the sequence in which components are repaired and the relative effort expended toward repairing a given component within a fixed time period.

4. The duration of component inoperability allowed by the plant's technical specifications directly affects the relative priorities assigned to certain maintenance events.

The availability of personnel and the priorities in effect at a given plant often determine the maintenance duration (as opposed to the relatively ideal case in which duration is directly proportional to the complexity of repair). The impact of the technical specifications on the relative priorities assigned to maintenance activities cannot be overemphasized. A major repair of a component that is allowed to be inoperable for a maximum of 72 hours will often be completed in less time than a minor adjustment of a component that is allowed to be inoperable indefinitely, even if both components are parts of engineered safeguards systems (however, with apparently different importance or available redundancy, as indicated by the differing technical specifications limitations). Because of these factors and because each plant has its own unique personnel and procedural limitations, it is extremely difficult to generalize maintenance duration data to several plants, even if it is applied to otherwise physically identical components.

1.6.1.3.1.2 Data Base Specialization. Detailed site specific component maintenance data was obtained by an extensive review of the Indian Point Unit 3 operating and maintenance records. This review provided nearly 4 years of specific component maintenance information. Because maintenance is infrequently performed on standby safety systems components during noncold shutdown periods, this site specific data was in many cases sparse and relatively inconclusive (because of the high variability exhibited by the small sample of events). Because of these generally small, variable sample sizes, the techniques of Bayesian specialization, as described in the main report, were used to integrate the site specific information with generalized prior data distributions. Thus, an expression for the state of knowledge about maintenance activities at Indian Point Unit 3 was developed which applies the correct weighting factors to both the detailed evidence and the available prior information.

As discussed in Sections 1.6.1.3.1.1.2 and 1.6.1.3.1.1.3, the frequency and duration of maintenance events are determined in a relatively independent manner through the combined effects of numerous factors (the technical specifications allowed duration of inoperability is one

important common factor). Both frequency and duration information are necessary to evaluate the impact of maintenance activities on the systems analyzed in this study. The frequency of maintenance defines the rate at which components are removed from service is a basis for evaluating recovery factors and human interactions; the duration and frequency combined determine the component unavailability to be applied in the quantification of system hardware failures during maintenance activities. Because the frequency and duration of maintenance are not directly related, a separate specialized distribution was developed for each of these parameters as it applies to each of the components included in the data base.

The prior distributions for maintenance event frequency were specialized using the Indian Point Unit 3 maintenance data by the direct application of Bayes' theorem, as described in the methodology discussion in the main report.

The general principles of Bayesian specialization apply equally to the maintenance duration data. However, the data obtained from the plant exhibits wide variability in the observed duration of the maintenance performed on each component. Because of the relatively small data sample for most components, this variability leads to a significant uncertainty about the mean duration to be applied in determining component unavailability due to maintenance. To correctly include this uncertainty about the mean duration, an extension of the specialization process described for component failure and maintenance frequency data was developed and applied to the site specific duration data. The results of this process were distributions of the mean duration of maintenance which account for the uncertainty in the site specific and generic data. These distributions were then combined with the specialized frequency distributions to obtain the component maintenance unavailability information to be applied in the system analyses. The methodology used in the development of the mean duration distributions is more fully described in the methodology section of the main report.

1.6.1.3.1.3 Comparison With Methodology Used in the Reactor Safety Study. The development methodology used in the RSS treatment of component maintenance data is similar in many respects to that used in this study, although the detail and depth of specialization in the RSS was limited because of the broad scope of the data base. Separate distributions for the frequency and duration of maintenance were developed based on discussions with plant maintenance personnel and using data from a review of the maintenance records of four plants during 1972. Because of the broad scope of the RSS, this site specific data was not directly included in the data base, but served in the development of a lognormal distribution model for maintenance event duration and provided general information for typical repair time distributions for four classifications of components.

A single broad distribution for maintenance event frequency was assigned uniformly to all component types. Because of the various factors influencing maintenance frequency, three general prior distributions for

frequency have been developed in this study. Each prior distribution is assigned to a specific component type, based on the conditions under which the component is operated at each plant (including the specific technical specifications limitations applied). The assigned prior distribution is then specialized using the available site specific data to produce a unique description of the maintenance frequency directly applicable to the component being analyzed.

The RSS distributions for maintenance event duration were developed for four general component classifications: (1) pumps, (2) valves, (3) diesel generators, and (4) instrumentation. In recognition of the strong influence of the technical specifications on event duration, the pump classification was further subdivided into two specialized distributions, one applicable to pumps having a 24-hour technical specifications inoperability time limit and one for pumps with a 72-hour time limit. As discussed, the site specific evidence and increased experience with general plant maintenance practices have led to the combination of pump and valve maintenance events into a single category of maintenance associated with a pump flow path. In this study, a total of four general prior distributions for maintenance event duration have been developed and specialized to the applicable components analyzed at each plant.

Because the current study is concerned with the analysis of specific components in a single plant, and because the level of detail available from the site specific data may be directly applied to this data base, the methodology for maintenance data development presented in this study, while generally similar to that discussed in the RSS, provides the level of specificity needed for a detailed analysis of each of the plant safety systems.

1.6.1.3.2 Component Maintenance Prior Distributions

The recirculation pumps have been excluded from the prior maintenance distributions presented in this section. These pumps are located inside the containment and are tested only during refueling outages with the unit at cold shutdown. Therefore, it would be extremely unlikely that any latent failures or degradation of these pumps would be detected during noncold shutdown periods. Furthermore, because of their location, the unit would have to be shut down for personnel radiation protection considerations before performing any maintenance on these pumps or their associated valves. Therefore, it is believed that no maintenance would be performed on these pumps during the periods of interest in this study.

1.6.1.3.2.1 Frequency of Maintenance. Prior distributions for the frequency of component maintenance were developed for three general component categories based on the component type, its normal service duty, and the applied technical specifications inoperability limitations. These distributions are described in Tables 1.6.1-5 through 1.6.1-7.

1.6.1.3.2.2 Duration of Maintenance. Because the plant technical specifications have most important influence on the duration of all but the most complex repair work, prior distributions for the duration of component maintenance were developed for four general component categories based primarily on their inoperability time limitations. These distributions are described in Tables 1.6.1-8A, 9A, 10A, and 11A.

Each of these distributions represents a single expression of the prior state of knowledge about the individual maintenance event durations. The mean value of each distribution is a single point estimate of the mean duration of maintenance for the given component type. To the extent that the given distribution represents the best estimate of the actual distribution of the duration data, the resulting mean value is the best estimate for the prior mean. To provide a framework for the expression of the uncertainty about this mean value (which must be included in the development of the component unavailability distributions), each of the distributions presented in Tables 1.6.1-8A, 9A, 10A, and 11A was expanded into a family of distributions by allowing the 5th and 95th percentiles of the lognormal curves to take on the ranges of values shown in Tables 1.6.1-8B, 9B, 10B, and 11B. The probability assigned to each of the values in the given range provides an expression of the uncertainty about the value of the parameter. The resulting distribution of mean values for maintenance event duration was then weighted in accordance with the relative probabilities assigned to the corresponding event duration distributions to express the "educated" prior states of knowledge about the distribution of the means presented in Tables 1.6.1-8A, 9B, 10B, and 11B.

1.6.1.3.2.3 Comparison With Distributions Used in the RSS. The maintenance frequency distribution applied to all components in the RSS is characterized by the following lognormal parameters (RSS, page III-54):

5th Percentile:	1 month between events
95th Percentile:	12 months between events
Mean:	4.6 months between events

This distribution corresponds closely to the prior distribution presented in Table 1.6.1-7 for continuous service components and components with a high maintenance frequency. Because the RSS distribution was developed using the maintenance event summaries from four units during a single year of operation, this distribution may be unrealistically biased toward a relatively high maintenance frequency. This is especially true in the case of standby components having very restrictive inoperability time limitations and reflects the expected lack of evidence of maintenance performed on these components in just 4 reactor years. While the distribution in the RSS may correctly model the frequency of maintenance as it applies to a broad collection of component types in several systems, this generally observed maintenance can be dominated by a relatively small subset of components with

relatively high maintenance frequencies. Therefore, the distribution is not necessarily uniformly applicable to any given component in a specific system, regardless of the component's normal operating status or its imposed inoperability restrictions.

The RSS distributions for component maintenance event duration include two cases for pumps, one with a 24-hour inoperability time limit, and one with a 72-hour limit, and one case for diesel generators, with essentially a 72-hour inoperability limit. The parameters characterizing these lognormal distributions are (RSS, Table III 5-3):

- Pumps, 24-Hour Time Limit:

  5th Percentile: 0.5 hour/event

  95th Percentile: 24 hours/event

  Mean: 6.9 hours/event

- Pumps, 72-Hour Time Limit:

  5th Percentile: 0.5 hour/event

  95th Percentile: 72 hours/event

  Mean: 18.8 hours/event

- Diesel Generators:

  5th Percentile: 2 hours/event

  95th Percentile: 72 hours/event

  Mean: 21.7 hours/event

The distributions for the pump cases compare favorably with the corresponding prior distributions presented in Tables 1.6.1-8A and 1.6.1-9A, although the RSS distributions tend to include more optimism toward accomplishing maintenance in a short time than do the distributions in this study (possibly due to the inclusion of tagout and return to service times in the component unavailability durations for this study). The differences between the distributions for the diesel generators are attributable primarily to the longer allowable inoperability period applied in this study as compared to that used in the RSS.

The prior distributions for maintenance frequency and duration developed in this study compare favorably with the information presented in the RSS if the differences in their levels of specificity are considered. The principal advantage of the more detailed distributions is that they provide specific information about the maintenance characteristics of a given component type at a given plant. Therefore, they give a more

realistic representation of the actual variability of maintenance practices than is available through the broadly applicable distributions which were, of necessity, used in the RSS.

1.6.1.3.3 Site Specific Component Maintenance Data

The maintenance data presented in Tables 1.6.1-12A through 1.6.1-18 was obtained by an extensive review of all available maintenance work permits in effect during noncold shutdown periods at Indian Point Unit 3 between May 25, 1976 and June 25, 1980. The work permits were used because they provide a single source of information detailing: (1) the specific components affected by a given maintenance event; (2) the resulting effects on the system (e.g., the positions of valves, which circuit breakers were tagged out, etc.); (3) the entire duration of component unavailability, including the required tagout and return to service periods; and (4) the times and dates spanned by the maintenance period (for correlation with unit power operation records).

The information presented in these tables includes:

- Reporting Hours. the total number of noncold shutdown calendar hours in the given year for which maintenance data was available (may be less than the total number of noncold shutdown hours because of missing or otherwise unavailable records).

- Component Hours. the total number of noncold shutdown component service hours in the reporting period (obtained from the product of the reporting hours and the number of components available for the given type being analyzed).

- Maintenance Events. the number of individual maintenance events performed on the given component type during the reporting period.

- Total Maintenance Hours. the total duration of the maintenance events performed during the reporting period.

The data is presented on an annual basis to allow the identification of possible trends or unique cases which may not be representative of the normally observed maintenance practices at the plant.

No maintenance was performed on the fan cooler units, auxiliary component cooling pumps or the recirculation pumps during the noncold shutdown reporting period covered by this data base.

1.6.1.3.4 Specialized Component Maintenance Data

1.6.1.3.4.1 Component Maintenance Frequency. The site specific maintenance frequency data presented in Tables 1.6.1-12A through 1.6.1-18 was used to update the general frequency distributions described in Tables 1.6.1-5 through 1.6.1-7 to obtain the specialized lognormal distributions for component maintenance frequency shown in Table 1.6.1-19.

1.6.1.3.4.2 Mean Duration of Component Maintenance. The duration of each maintenance event used to determine the data base summarized in Tables 1.6.1-12A through 1.6.1-18 provided the site specific evidence to update the families of generalized event duration distributions developed from Tables 1.6.1-8A through 1.6.1.-11B. The resulting specialized distributions of the mean duration of maintenance for each component type are presented in Figures 1.6.1-2 through 1.6.1-13.

1.6.1.3.4.3 Component Unavailability Due to Maintenance. To develop specialized information for the unavailability of components at Indian Point Unit 3 due to maintenance, the event frequency distributions presented in Table 1.6.1-19 and the distributions of event mean duration shown in Figures 1.6.1-2 through 1.6.1-13 were discretized and multiplied together using discrete probability distribution arithmetic. The resulting distributions of component unavailability are shown in Figures 1.6.1-14 through 1.6.1-21.

TABLE 1.6.1-5

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MAINTENANCE FREQUENCY - STANDBY PUMP OR VALVES, TESTED MONTHLY OR QUARTERLY

Distribution:	Lognormal
5th Percentile:	3.86×10^{-5} event/hour (1 event/36 months)
95th Percentile:	1.54×10^{-4} event/hour (1 event/9 months)
Mean:	8.42×10^{-5} event/hour (1 event/16.5 months)
Variance:	1.37×10^{-9}

Basis: Distribution range is indicative of very light duty components subjected to relatively frequent test starts which would detect component failures. A minimal preventive maintenance program is applied due to the standby nature of these components and the technical specifications inoperability criteria applied to maintenance performed during noncold shutdown periods.

Applicable to Indian Point Unit 3 Components:

- Containment Spray Pumps
- Safety Injection Pumps
- Auxiliary Component Cooling Pumps
- Residual Heat Removal Pumps*

*Although these pumps are operated continuously during all cold shutdown periods they are purely standby pumps during noncold shutdown periods and maintenance performed during these periods would apply to failures detected during testing.

TABLE 1.6.1-6

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MAINTENANCE FREQUENCY - ALTERNATING SERVICE PUMP, TESTED MONTHLY OR QUARTERLY

Distribution:	Lognormal
5th Percentile:	5.79×10^{-5} event/hour (1 event/24 months)
95th Percentile:	2.31×10^{-4} event/hour (1 event/6 months)
Mean:	1.26×10^{-4} event/hour (1 event/11 months)
Variance:	3.09×10^{-9}

Basis: Distribution range is indicative of medium duty components subjected to periodic testing. Due to the generally less restrictive technical specifications inoperability criteria applied to these components, a nominal preventive maintenance frequency of approximately one event per 18 months of pump operation is included to account for routine inspections, lubrication programs, etc., performed during noncold shutdown periods.

Applicable to Indian Point Unit 3 Components:

- Auxiliary Feedwater Pumps

TABLE 1.6.1-7

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MAINTENANCE FREQUENCY - CONTINUOUS SERVICE COMPONENTS AND COMPONENTS SUBJECT TO HIGH FREQUENCY OF MAINTENANCE

Distribution:	Lognormal
5th Percentile:	7.72×10^{-5} event/hour (1 event/18 months)
95th Percentile:	4.63×10^{-4} event/hour (1 event/3 months)
Mean:	2.19×10^{-4} event/hour (1 event/6.3 months)
Variance:	1.66×10^{-8}

Basis: Distribution range is indicative of continuous service components or components requiring relatively frequent routine maintenance. Due to their relaxed technical specifications inoperability criteria, a nominal preventive maintenance frequency of approximately one event per 12 months of component service time is included to account for the necessary periodic inspections, routine repairs, and general overhauls typically performed on these components during noncold shutdown periods.

Applicable to Indian Point Unit 3 Components:

- Service Water Pumps
- Component Cooling Pumps
- Fan Cooler Units*
- Diesel Generators**

*Although the fan cooler units are located inside the containment and are relatively inaccessible during power operation, they are in continuous service and maintenance is expected to be required on such items as circuit breakers, starting controls, service water supply and return valves, etc. All of this equipment is accessible for routine maintenance and repair during noncold shutdown periods.
**The diesel generators are tested frequently, subject to minor failures and degradation requiring routine maintenance, and generally overhauled or tuned up according to a nominal preventive maintenance schedule.

TABLE 1.6.1-8A

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MAINTENANCE DURATION (24-HOUR TIME LIMIT)

Distribution:	Lognormal
5th Percentile:	2 hours/event
95th Percentile:	24 hours/event
Mean:	9.2 hours/event
Variance:	65

Basis: Only the most routine maintenance can be performed with a component unavailability time (including removal and return to service operations) of less than two hours. The 24-hour time limit for operation dictates that major scheduled maintenance will be performed only during periods of cold shutdown. Any major nonroutine maintenance or repairs requiring more than 24 hours to complete will necessitate unit shutdown. Since the data base excludes all maintenance performed during cold shutdown, if a maintenance event requires significantly longer than 24 hours to complete, the extended repair time is not included in the data base.

Applicable to Indian Point Unit 3 Components:

- Containment Spray Pumps
- Residual Heat Removal Pumps
- Safety Injection Pumps
- Fan Cooler Units*

*The 24-hour time limit strictly applies to only fan cooler units 32, 34 and 35. Due to their power supplies, fan cooler units 31 and 33 have an applied 7-day inoperability time limit. However, since the actual maintenance performed on each of these units should be similar and since the specialized maintenance duration distribution will be applied to all five fan cooler units, the 24-hour limit has been applied to all of the fan coolers for this prior distribution.

TABLE 1.6.1-8B

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MEAN DURATION OF MAINTENANCE (24-HOUR TIME LIMIT)

Parameters Characterizing Range of Lognormal Duration Distributions:

5th Percentile (hours/event)	Probability	95th Percentile (hours/event)	Probability
1.0	0.05		
1.5	0.15	16	0.10
2.0	0.50	24	0.50
2.5	0.15	32	0.15
3.0	0.10	40	0.15
3.5	0.05	48	0.10

Resulting Prior Distribution of Mean Duration of Maintenance:

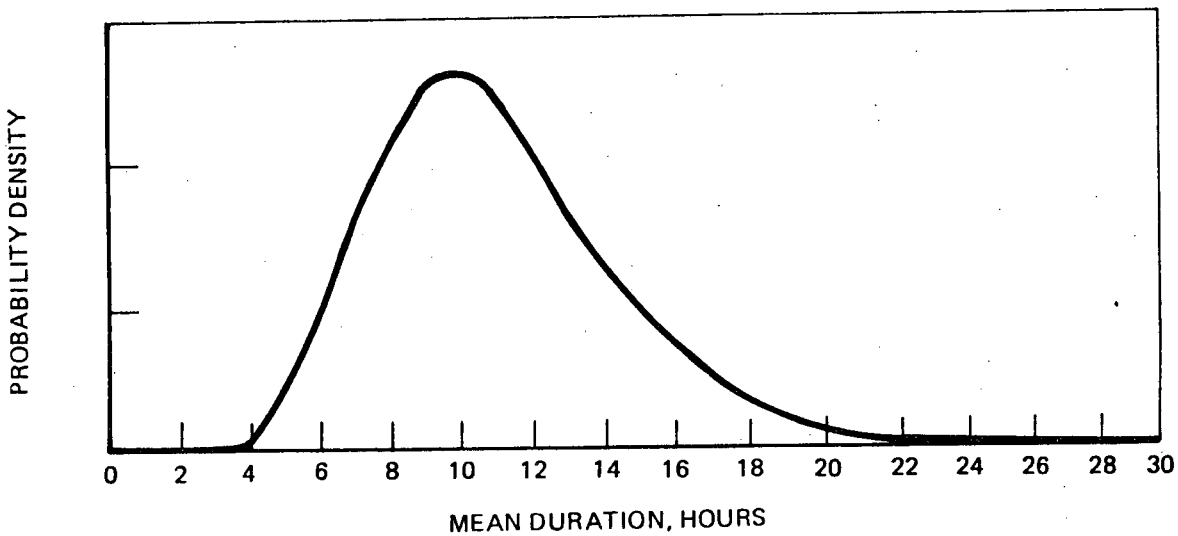

TABLE 1.6.1-9A

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MAINTENANCE DURATION (72-HOUR TIME LIMIT)

Distribution:	Lognormal
5th Percentile:	2 hours/event
95th Percentile:	60 hours/event
Mean:	18.7 hours/event
Variance:	668

Basis: Only the most routine maintenance can be performed with a component unavailability time (including removal and return to service operations) of less than 2 hours. The 72-hour time limit for operation dictates that major maintenance and repair activities will be performed during cold shutdown periods. Because of this limit, the maximum duration of any single event included in the data base is 92 hours, since the unit would be placed in the cold shutdown condition within this approximate time limit. The majority of relatively routine maintenance and some extensive repairs will be completed within 2-1/2 days, given the high priority assigned to returning the equipment to service within 72 hours.

Applicable to Indian Point Unit 3 Components:

- Auxiliary Feedwater Pumps

TABLE 1.6.1-9B

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MEAN DURATION OF MAINTENANCE (72-HOUR TIME LIMIT)

Parameters Characterizing Range of Lognormal Duration Distributions:

5th Percentile (hours/event)	Probability	95th Percentile (hours/event)	Probability
1.0	0.05	-	-
2.0	0.50	24	0.05
3.0	0.15	36	0.05
4.0	0.10	48	0.15
5.0	0.05	60	0.50
6.0	0.05	72	0.15
7.0	0.05	84	0.05
8.0	0.05	96	0.05

Resulting Prior Distribution of Mean Duration of Maintenance.

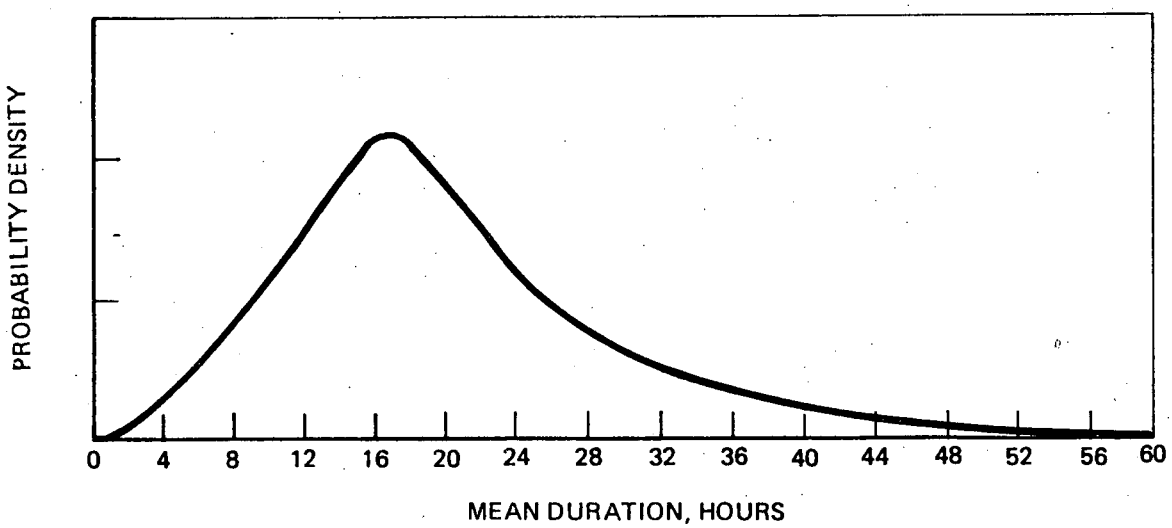

TABLE 1.6.1-10A

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MAINTENANCE DURATION (7-DAY TIME LIMIT)

Distribution:	Lognormal
5th Percentile:	2 hours/event
95th Percentile:	120 hours/event
Mean:	33.6 hours/event
Variance:	4.18×10^3

Basis: Only the most routine maintenance can be performed with a component unavailability time (including removal and return to service operations) of less than 2 hours. The 7-day time limit for unit operation dictates that most maintenance will be prioritized to be completed within approximately 5 days to allow for possible unforeseen delays. Furthermore, since most scheduled major maintenance and equipment overhaul is performed during the Monday through Friday work week, the 5-day time limit applies to most of these planned activities as well.

Applicable to Indian Point Unit 3 Components:

- Diesel Generators

TABLE 1.6.1-10B

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MEAN DURATION OF MAINTENANCE (7-DAY TIME LIMIT)

Parameters Characterizing Range of Lognormal Duration Distributions:

5th Percentile (hours/event)	Probability	95th Percentile (hours/event)	Probability
1	0.05	48	0.05
2	0.50	72	0.10
4	0.15	96	0.10
8	0.10	120	0.50
12	0.10	144	0.15
16	0.05	168	0.05
24	0.05	240	0.05

Resulting Prior Distribution of Mean Duration of Maintenance:

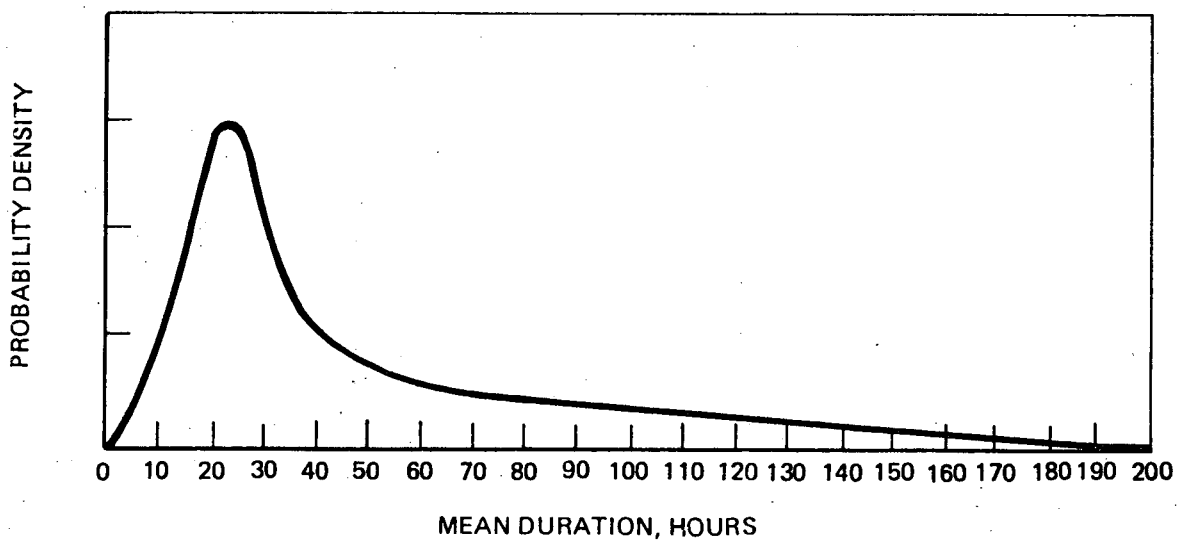

TABLE 1.6.1-11A

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MAINTENANCE DURATION
(NO TIME LIMIT)

Distribution:	Lognormal
5th Percentile:	4 hours/event
95th Percentile:	336 hours/event
Mean:	91 hours/event
Variance:	4.23×10^4

Basis: Given the relatively low priority generally assigned to maintenance of these components (with respect to more restrictive components), the approximate minimum time required for performance of most maintenance, including removal and return to service operations, is 4 hours. The majority of maintenance events, including major repairs or component replacement, should be accomplished within 2 weeks, given only moderate priority. A number of events could, of course, take considerably longer to complete, but these events are the exceptions and should not account for more than 5% of all maintenance activities.

Applicable to Indian Point Unit 3 Components:

- Service Water Pumps*
- Component Cooling Pumps
- Auxiliary Component Cooling Pumps**

*When one service water pump becomes inoperable, the nuclear system loads must be transferred to the redundant pump header within 8 hours. After this transfer, the inoperable pump may remain out of service indefinitely and is unavailable for operation on the nuclear system header.
**One auxiliary component cooling pump per recirculation pump cooling header may be inoperable indefinitely.

TABLE 1.6.1-11B

INDIAN POINT 3 PRIOR DISTRIBUTION FOR MEAN DURATION OF MAINTENANCE (NO TIME LIMIT)

Parameters Characterizing Range of Lognormal Duration Distribution:

5th Percentile (hours/event)	Probability	95th Percentile (hours/event)	Probability
2	0.05	24	0.05
4	0.50	48	0.10
8	0.20	120	0.20
16	0.10	336	0.50
24	0.10	720	0.10
48	0.05	2,000	0.05

Resulting Prior Distribution of Mean Duration of Maintenance:

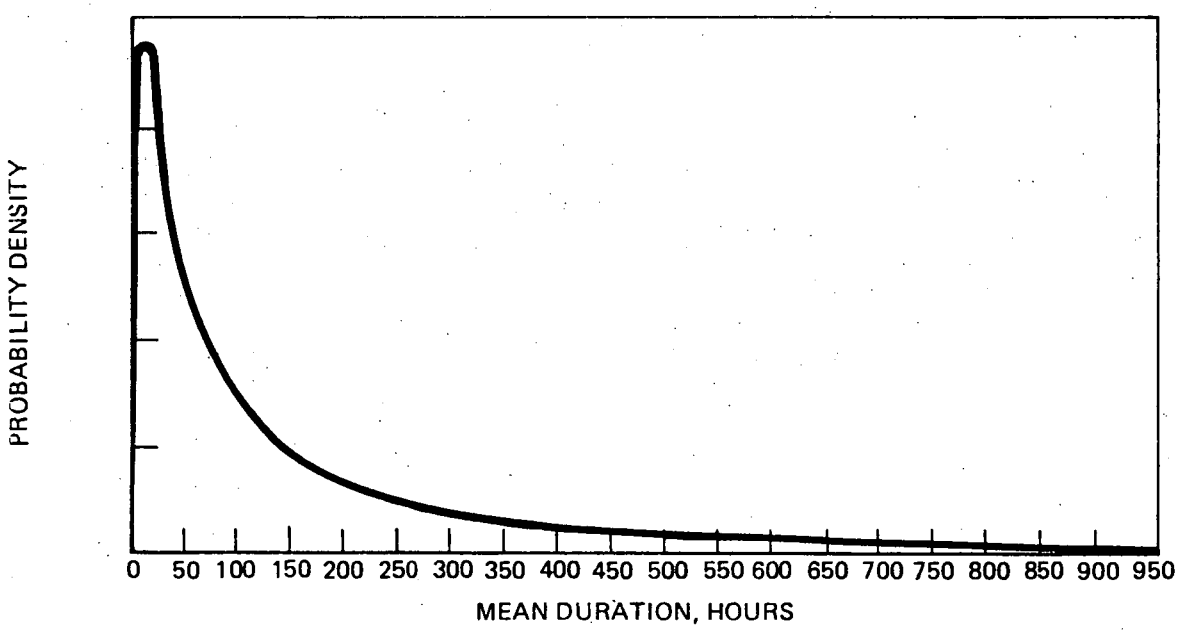

TABLE 1.6.1-12A

INDIAN POINT 3 COMPONENT TYPE: TURBINE-DRIVEN AUXILIARY FEEDWATER PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1976	4,728	4,728	2	73
1977	3,528	3,528	0	0
1978	2,592	2,592	1	92*
1979	5,808	5,808	1	9
1980	3,264	3,264	1	4

*The current technical specifications for Indian Point 3 allow one auxiliary pump to be inoperable for 72 hours during power operation. If the pump is not returned to service within 72 hours, the unit must be shut down within an additional 12 hours and cooled to <350°F as soon as practicable following shutdown. The maximum total elapsed time from the initiation of maintenance to cold shutdown is thus approximately 92 hours (allowing 8 hours for cooldown to <350°F). Since these technical specifications were recently implemented, the historical data has been modified to account for this maximum allowable inoperability period by truncating all maintenance events extending beyond 92 hours to this time limit. This truncation was applied to one event in 1978 with a duration of 2,479 hours to obtain the given times.

TABLE 1.6.1-12B

INDIAN POINT 3 COMPONENT TYPE: MOTOR-DRIVEN AUXILIARY FEEDWATER PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1976	4,728	9,456	2	7
1977	3,528	7,056	2	160*
1978	2,592	5,184	0	0
1979	5,808	11,616	0	0
1980	3,264	6,528	4	75

*The current technical specifications for Indian Point 3 allow one auxiliary pump to be inoperable for 72 hours during power operation. If the pump is not returned to service within 72 hours, the unit must be shut down within an additional 12 hours and cooled to <350°F as soon as practicable following shutdown. The maximum total elapsed time from the initiation of maintenance to cold shutdown is thus approximately 92 hours (allowing 8 hours for cooldown to <350°F). Since these technical specifications were recently implemented, the historical data has been modified to account for this maximum allowable inoperability period by truncating all maintenance events extending beyond 92 hours to this time limit. This truncation was applied to one event in 1977 with a duration of 3,120 hours to obtain the given times.

TABLE 1.6.1-13

INDIAN POINT 3 COMPONENT TYPE: COMPONENT COOLING PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1976	4,728	14,184	1	291
1977	3,528	10,584	0	0
1978	2,592	7,776	0	0
1979	5,808	17,424	0	0
1980	3,264	9,792	1	3

TABLE 1.6.1-14

INDIAN POINT 3 COMPONENT TYPE: CONTAINMENT SPRAY PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1976	4,728	9,456	0	0
1977	3,528	7,056	0	0
1978	2,592	5,184	0	0
1979	5,808	11,616	0	0
1980	3,264	6,528	2	20

TABLE 1.6.1-15

INDIAN POINT 3 COMPONENT TYPE: RESIDUAL HEAT REMOVAL PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1976	4,728	9,456	0	0
1977	3,528	7,056	0	0
1978	2,592	5,184	1	16
1979	5,808	11,616	0	0
1980	3,264	6,528	0	0

TABLE 1.6.1-16

INDIAN POINT 3 COMPONENT TYPE: SAFETY INJECTION PUMPS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1976	4,728	14,184	0	0
1977	3,528	10,584	1	66
1978	2,592	7,776	0	0
1979	5,808	17,424	0	0
1980	3,264	9,792	0	0

TABLE 1.6.1-17

INDIAN POINT 3 COMPONENT TYPE: SERVICE WATER PUMPS(1)

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1976	4,728	28,368	6	11
1977	3,528	21,168	1	9
1978	2,592	15,552	4	354(2)
1979	5,808	34,848	10	1,612(3)
1980	3,264	19,584	19	410(4)

(1) Data base includes only service water pumps 31-36
(2) Includes one event of a 321-hour duration
(3) Includes one event of a 864-hour duration
(4) Includes one event of a 183-hour duration

TABLE 1.6.1-18

INDIAN POINT 3 COMPONENT TYPE: DIESEL GENERATORS

Year	Reporting Hours	Component Hours	Maintenance Events	Total Maintenance Hours
1976	4,728	14,184	5	361*
1977	3,528	10,584	4	104
1978	2,592	7,776	1	13
1979	5,808	17,424	6	15
1980	3,264	9,792	3	36

*One event reported in 1976 had a duration of 603 hours, during which the unit remained in hot shutdown. This event is considered to be non-representative of normal operating and maintenance practices, and its duration was truncated to 244 hours to obtain the given time. (244 hours includes 7 days of operation as allowed by the plant's technical specifications and an additional 76 hours prior to achieving cold shutdown: 4 hours to shutdown, 48 hours in hot shutdown, and 24 hours to cool down to cold shutdown).

TABLE 1.6.1-19

INDIAN POINT 3 SPECIALIZED COMPONENT MAINTENANCE FREQUENCY DATA

Component	Site Specific Data		Prior Distribution Table	Specialized Frequency Distribution*	
	Events	Service Hours		Mean (events/hour)	Variance
Turbine-Driven Auxiliary Feedwater Pumps	5	1.99×10^4	1.6.1-6	1.64×10^{-4}	3.06×10^{-9}
Motor-Driven Auxiliary Feedwater Pumps	8	3.98×10^4	1.6.1-6	1.72×10^{-4}	2.40×10^{-9}
Component Cooling Pumps	2	5.98×10^4	1.6.1-7	8.37×10^{-5}	8.24×10^{-10}
Containment Spray Pumps	2	3.98×10^4	1.6.1-5	7.11×10^{-5}	5.98×10^{-10}
Residual Heat Removal Pumps	1	3.98×10^4	1.6.1-5	6.33×10^{-5}	4.97×10^{-10}
Safety Injection Pumps	1	5.98×10^4	1.6.1-5	5.50×10^{-5}	3.44×10^{-10}
Service Water Pumps	40	1.20×10^5	1.6.1-7	3.18×10^{-4}	1.97×10^{-9}
Diesel Generators	19	5.98×10^4	1.6.1-7	2.92×10^{-4}	3.97×10^{-9}
Auxiliary Component Cooling Pumps	0	7.97×10^4	1.6.1-5	4.43×10^{-5}	2.13×10^{-10}
Fan Cooler Units	0	9.96×10^4	1.6.1-7	5.06×10^{-5}	2.58×10^{-10}

*Distributions are lognormal.

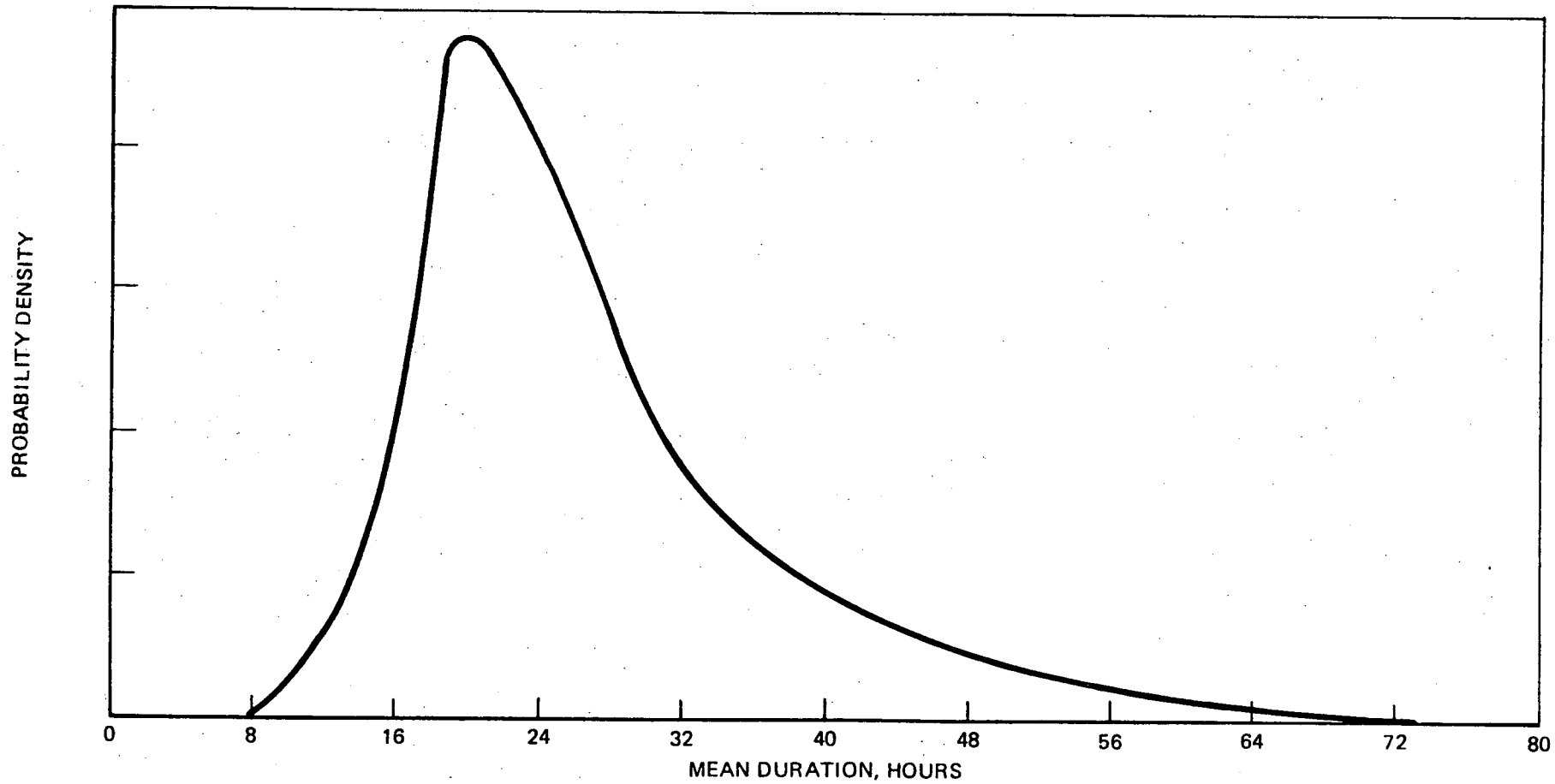

Figure 1.6.1-2. Indian Point 3 Turbine-Driven Auxiliary Feedwater Pump Specialized Mean Duration of Maintenance

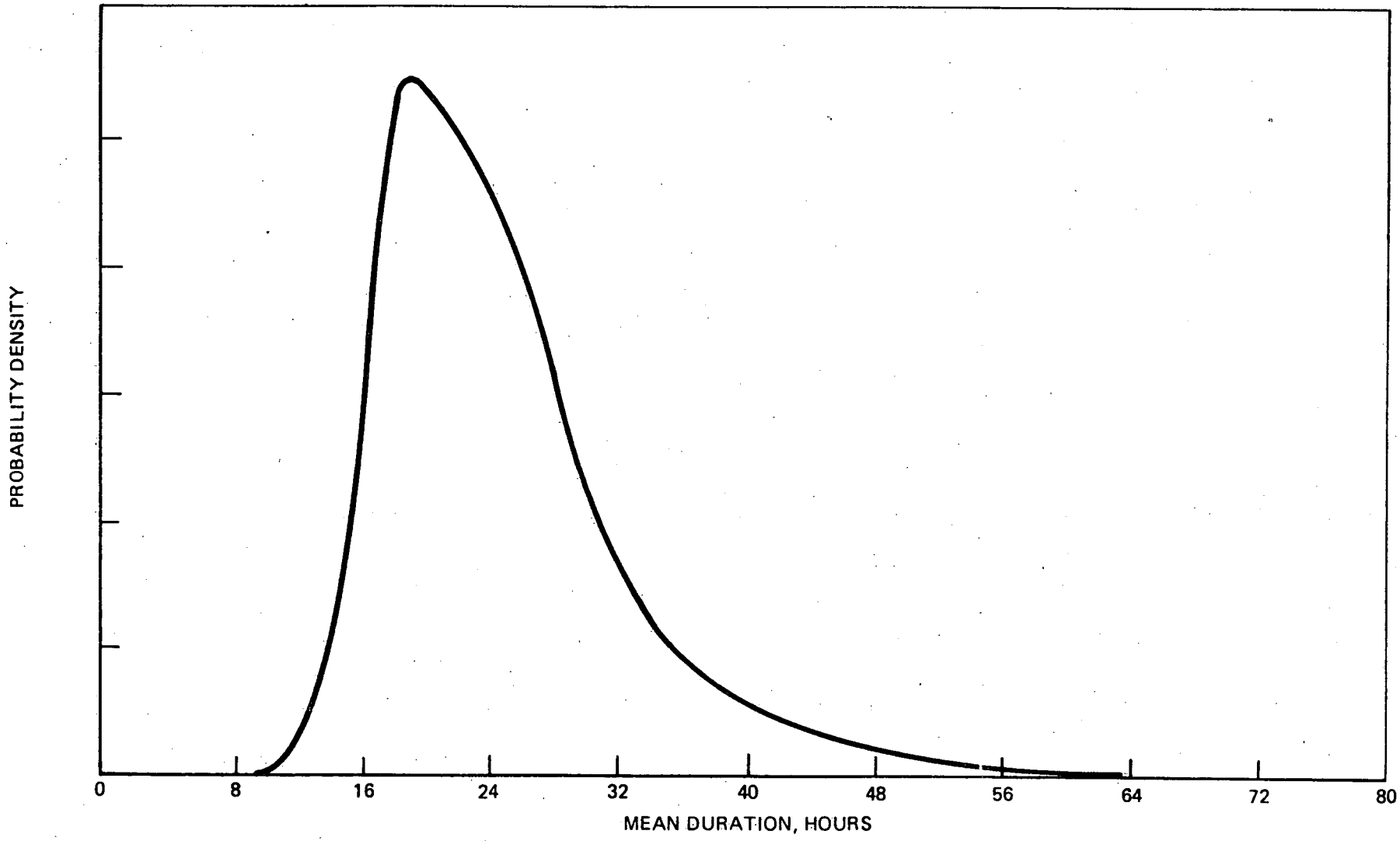

Figure 1.6.1-3. Indian Point 3 Motor-Driven Auxiliary Feedwater Pumps Specialized Mean Duration of Maintenance

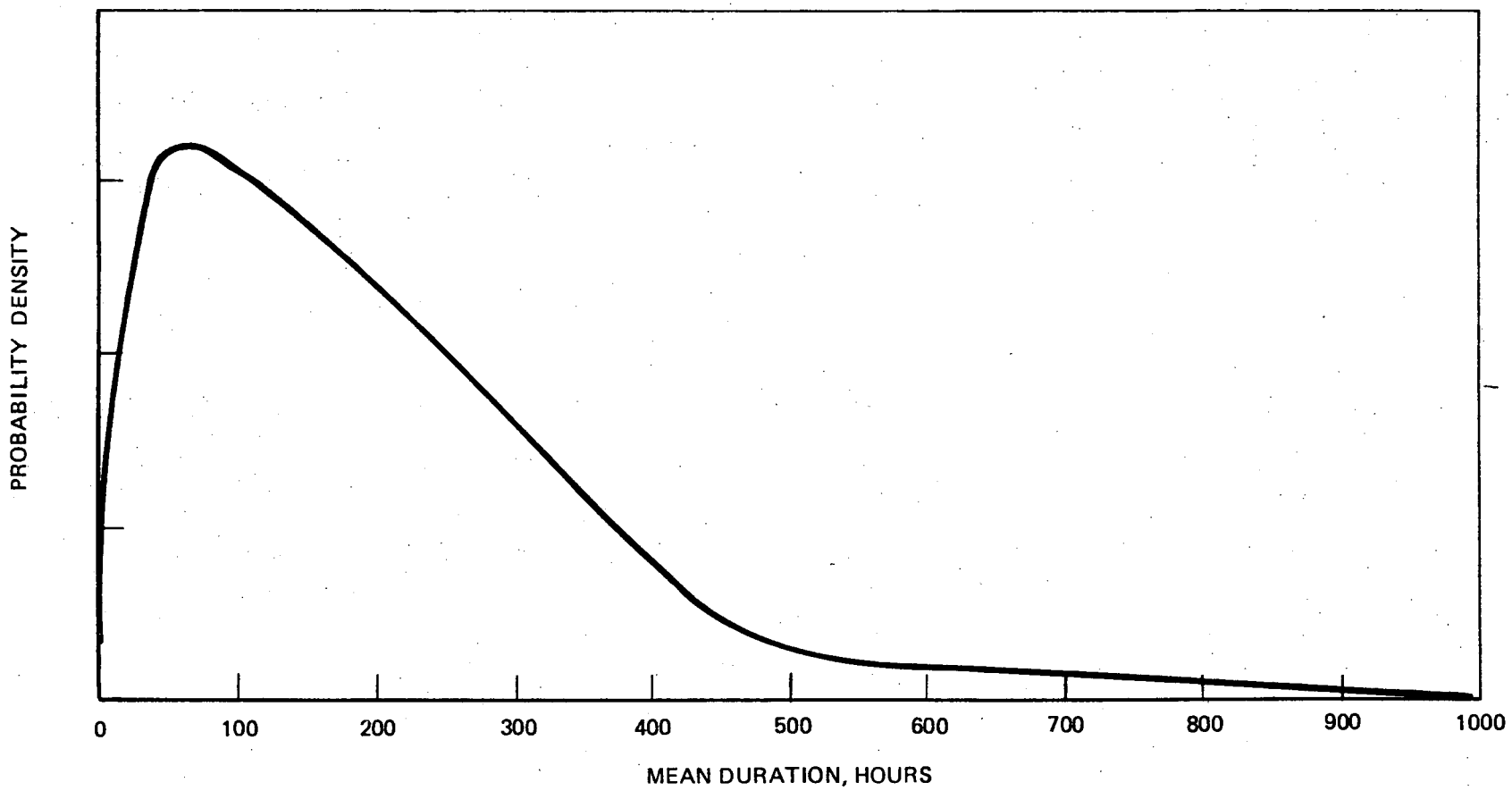

Figure 1.6.1-4. Indian Point 3 Component Cooling Pumps Specialized Mean Duration of Maintenance

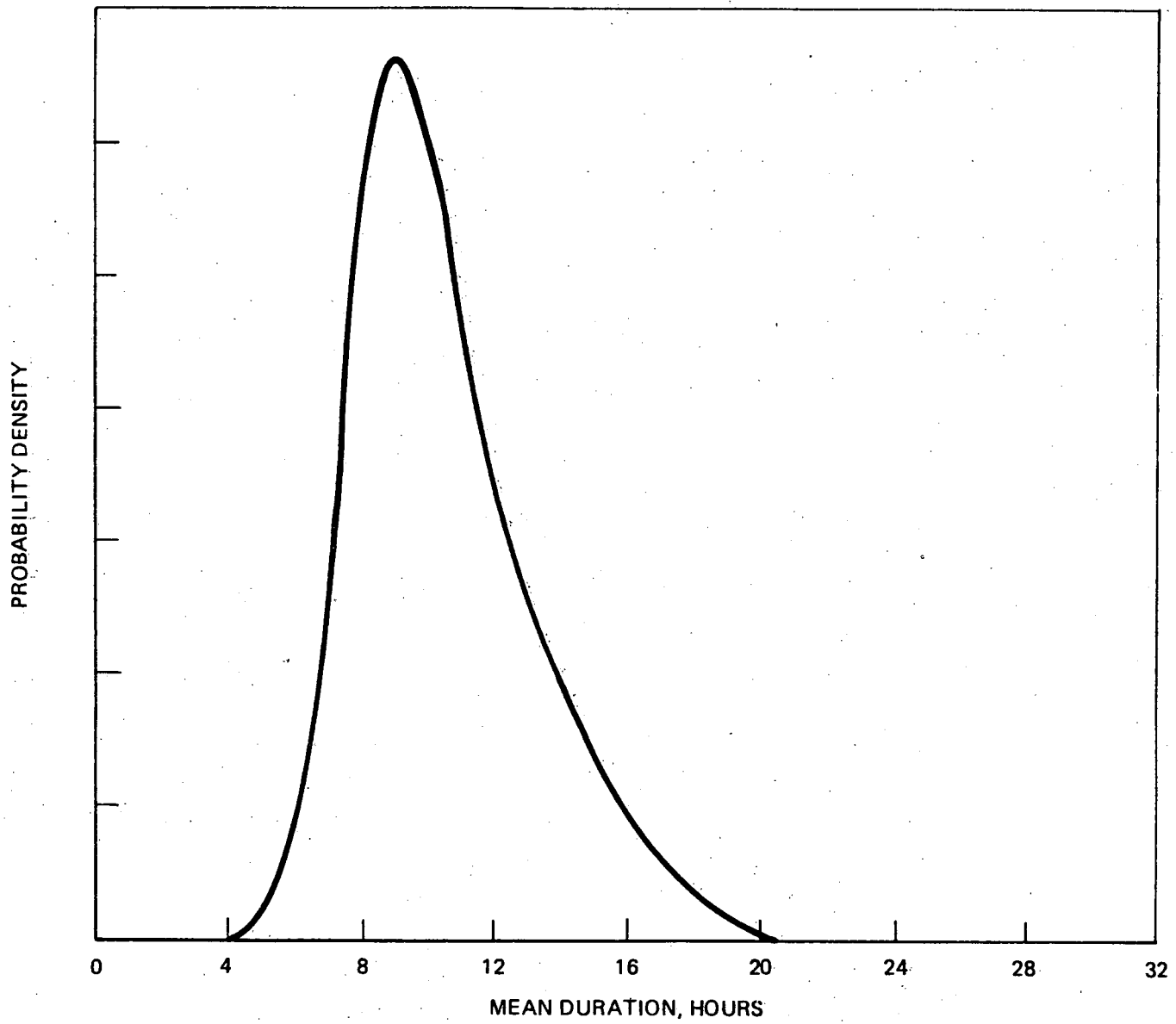

Figure 1.6.1-5. Indian Point 3 Containment Spray Pumps Specialized Mean Duration of Maintenance

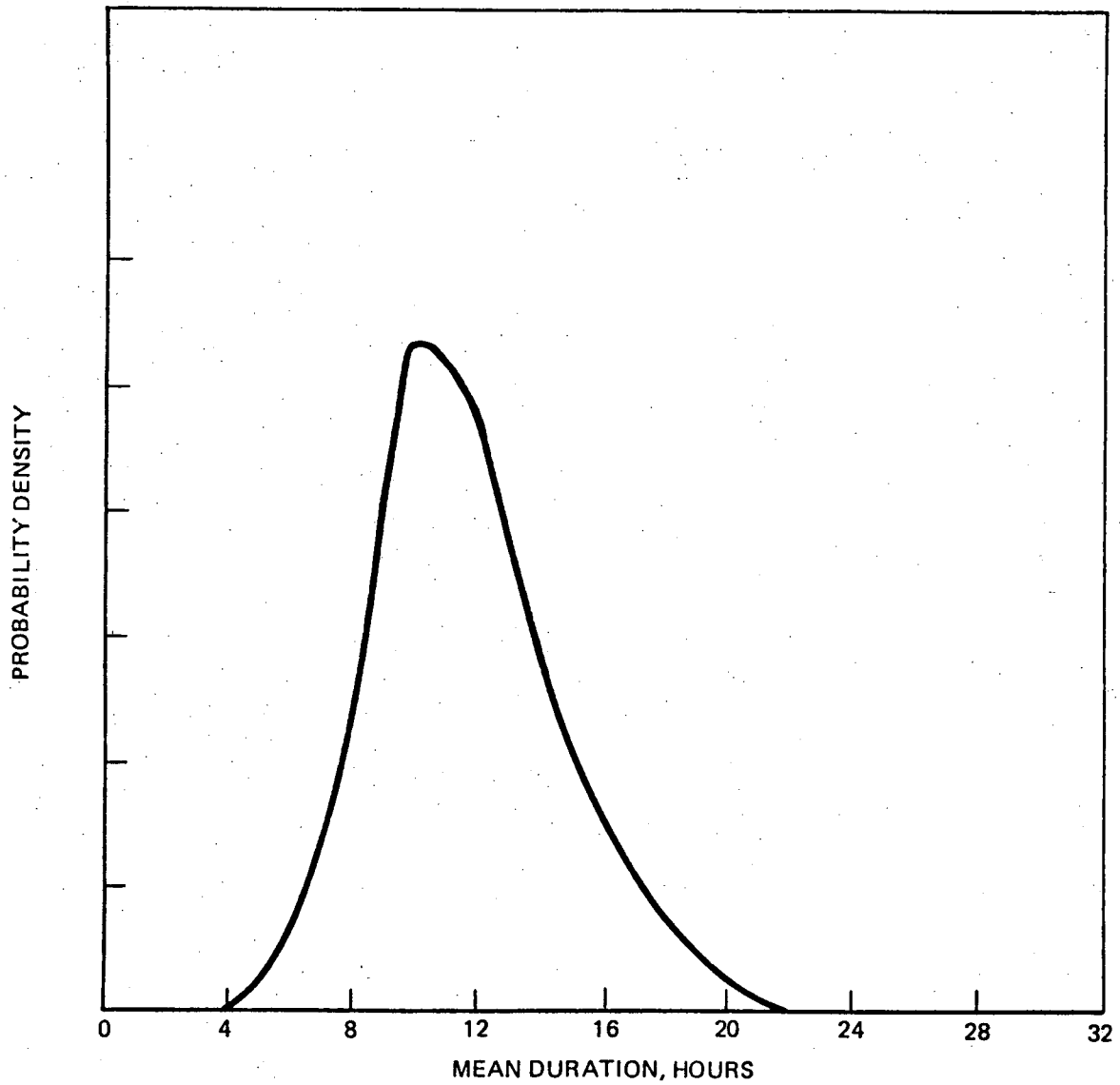

Figure 1.6.1-6. Indian Point 3 Residual Heat Removal Specialized Mean Duration of Maintenance

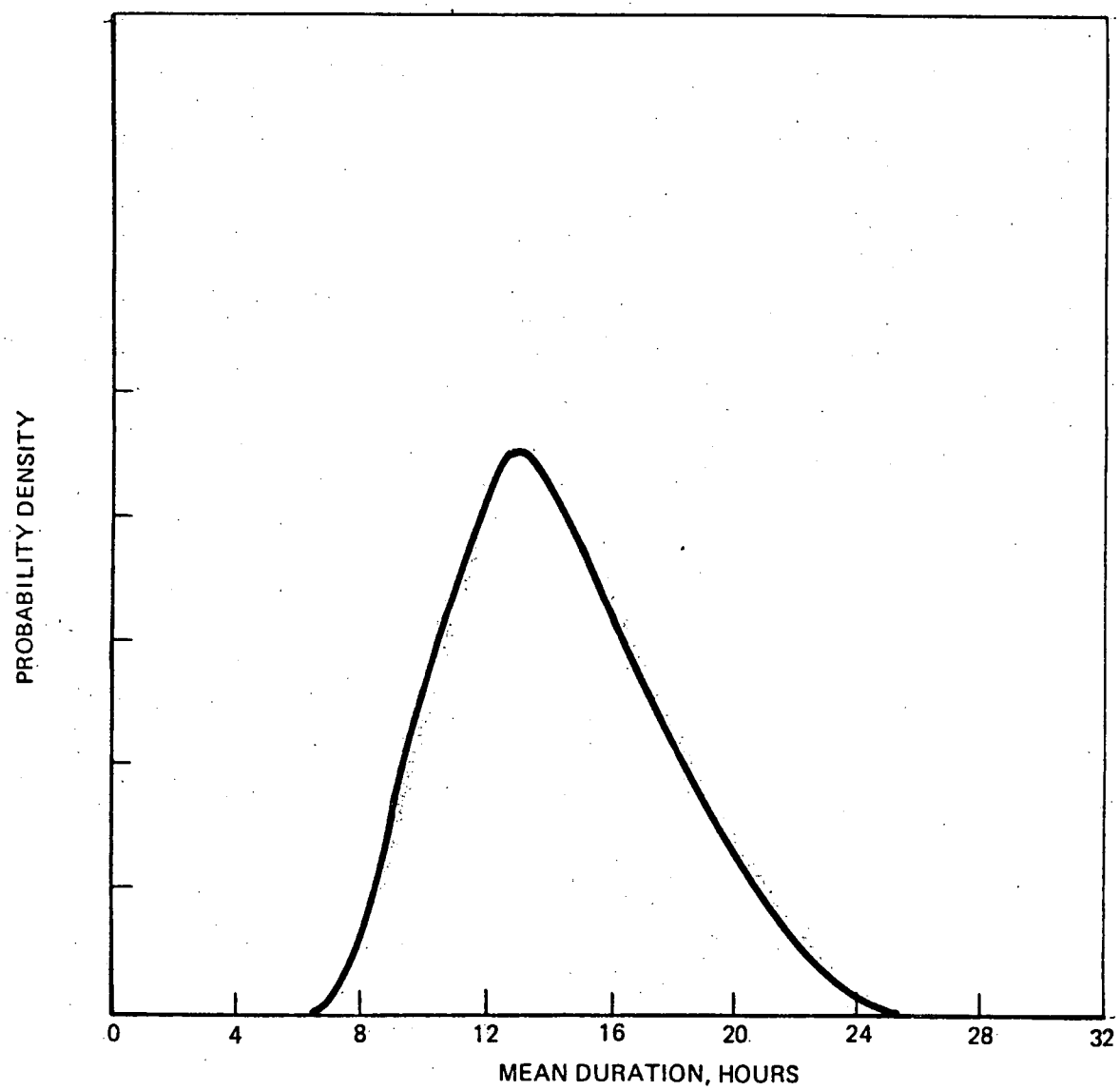

Figure 1.6.1-7. Indian Point 3 Safety Injection Pumps
Specialized Mean Duration of Maintenance

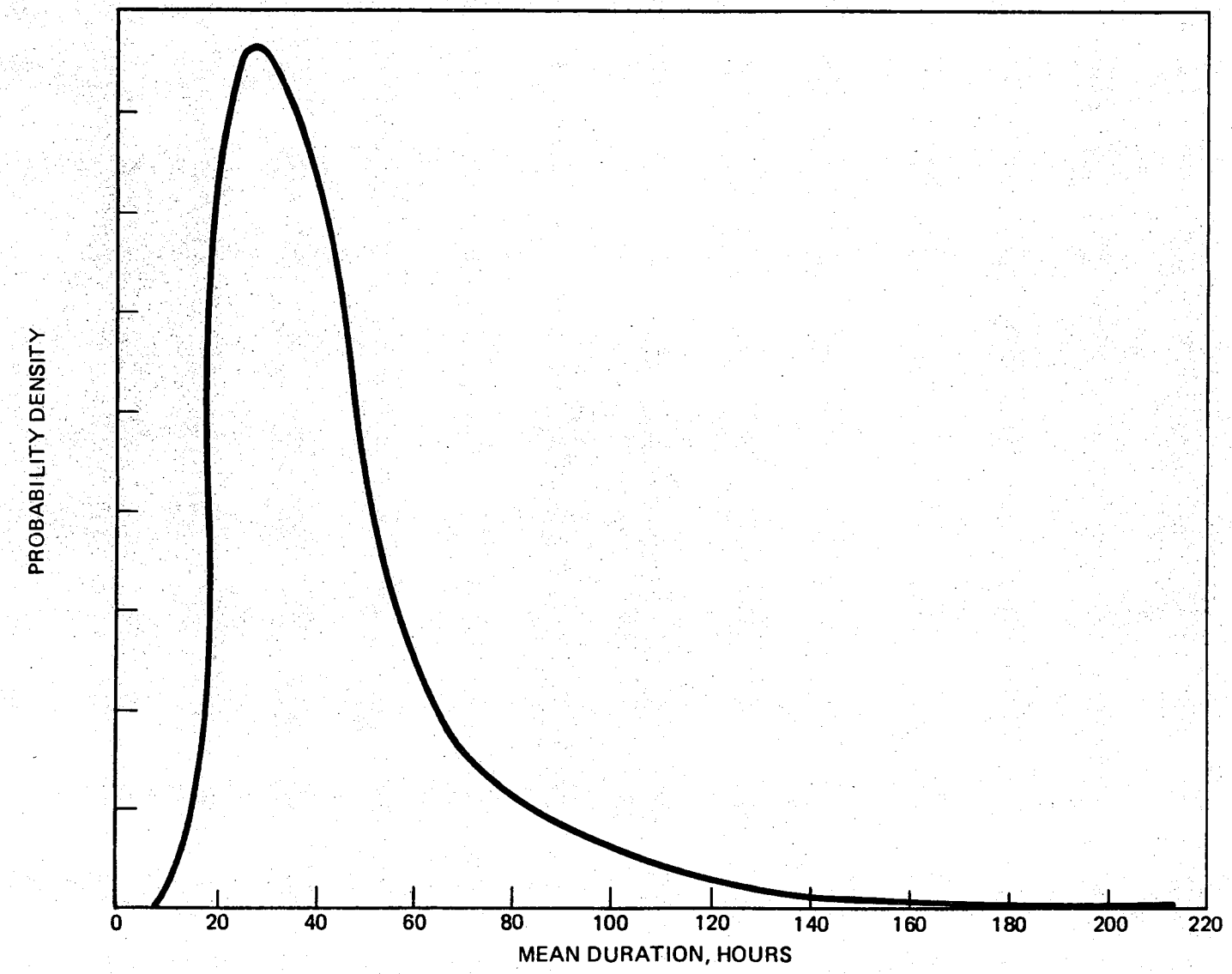

Figure 1.6.1-8. Indian Point 3 Service Water Pumps
Specialized Mean Duration of Maintenance

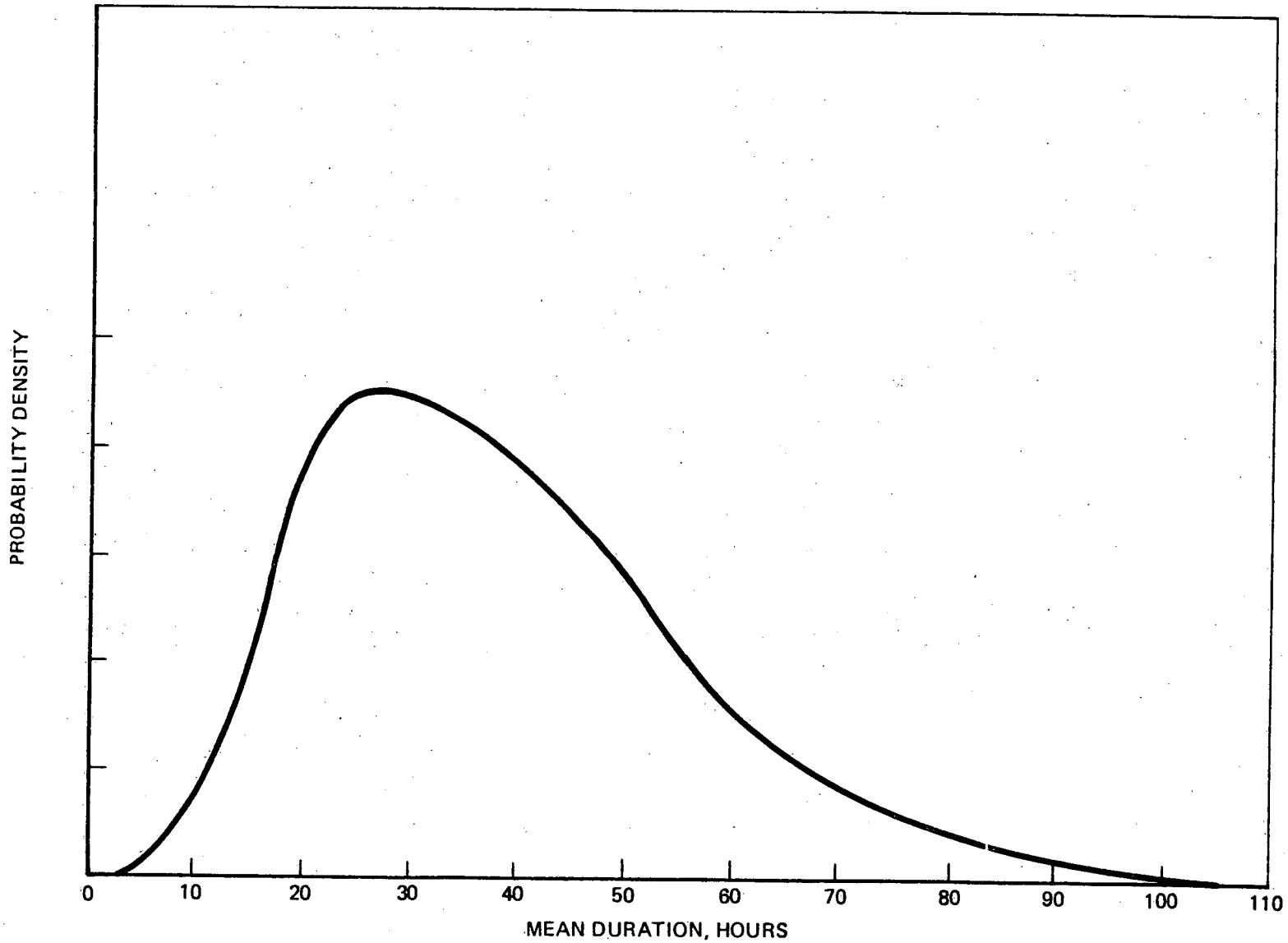

Figure 1.6.1-9. Indian Point 3 Diesel Generators
Specialized Mean Duration of Maintenance

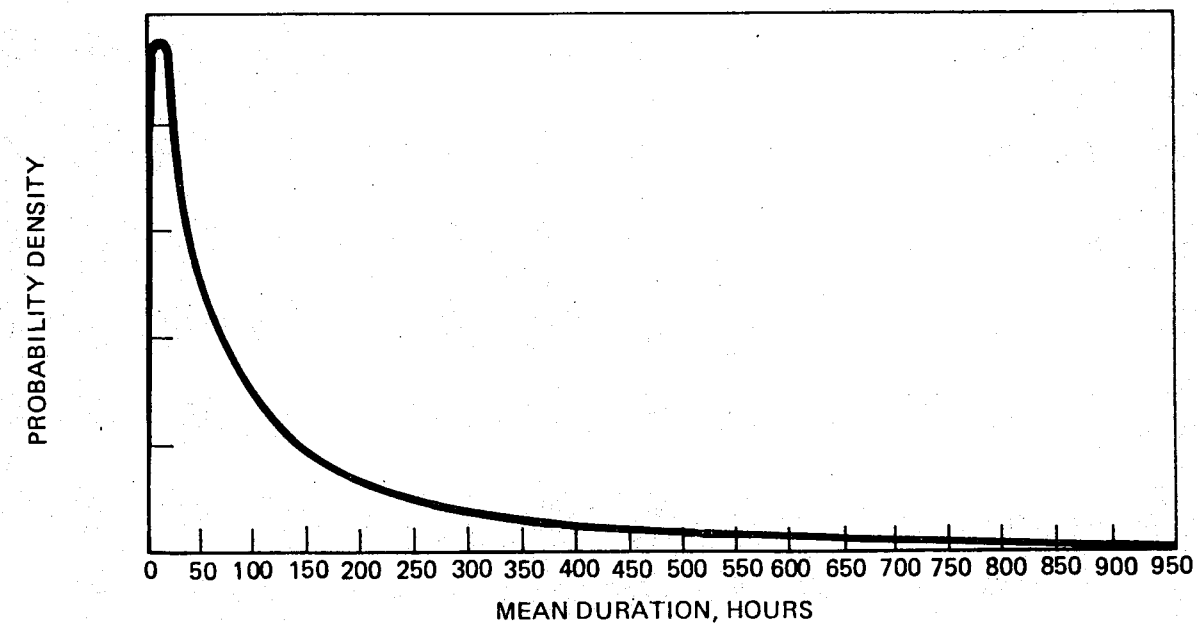

Figure 1.6.1-10. Indian Point 3 Auxiliary Component Cooling Pumps
Specialized Mean Duration of Maintenance

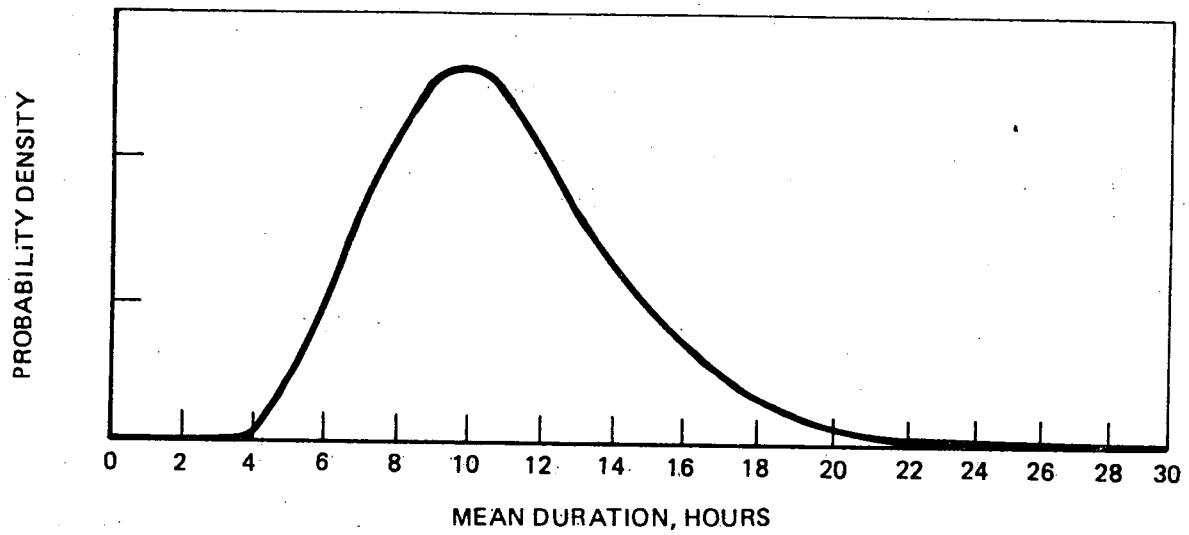

Figure 1.6.1-11. Indian Point 3 Fan Cooler Units
Specialized Mean Duration of Maintenance

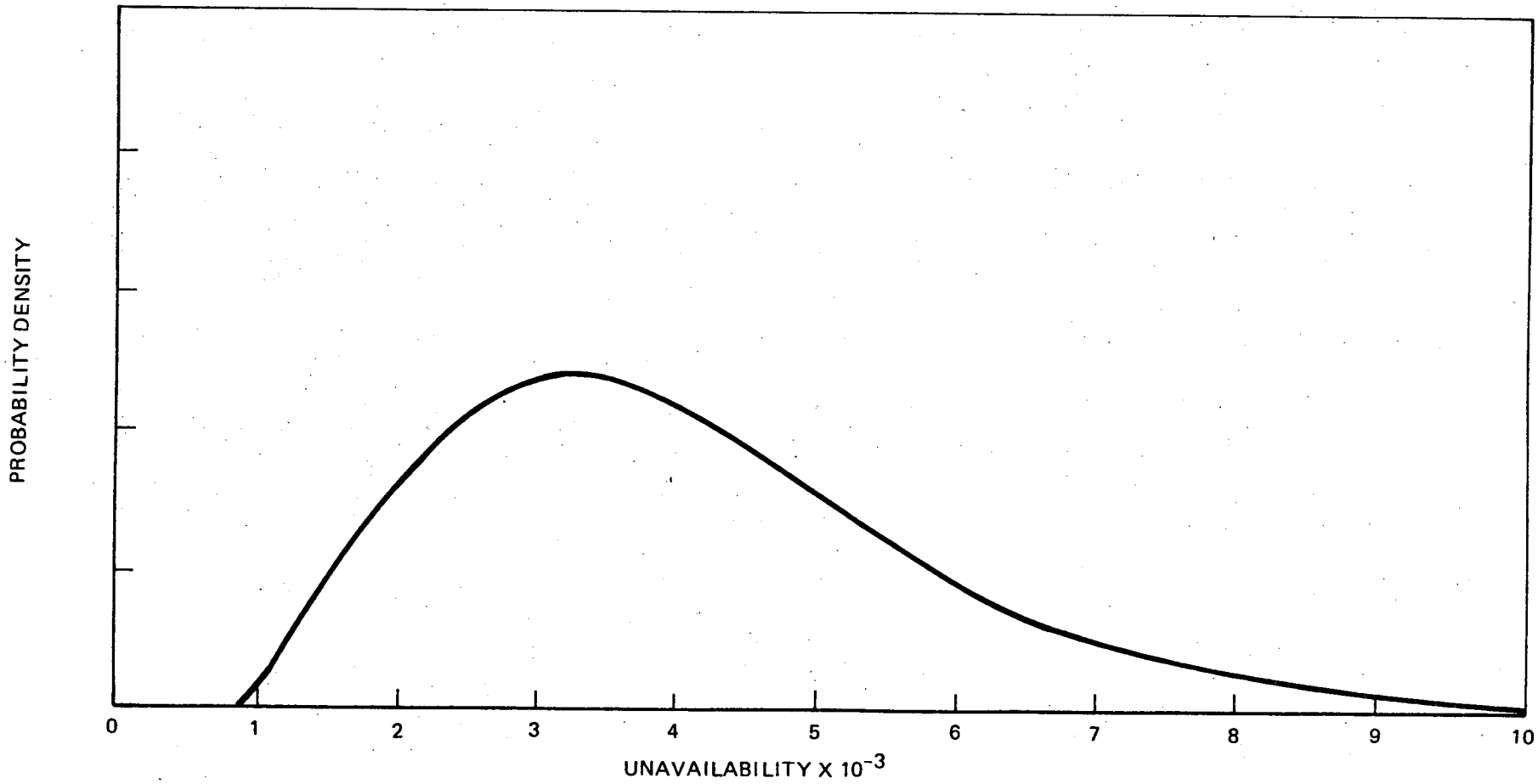

Figure 1.6.1-12. Indian Point 3 Turbine-Driven Auxiliary Feedwater Pump Unavailability Due to Maintenance

(Mean = 4.16×10^{-3})

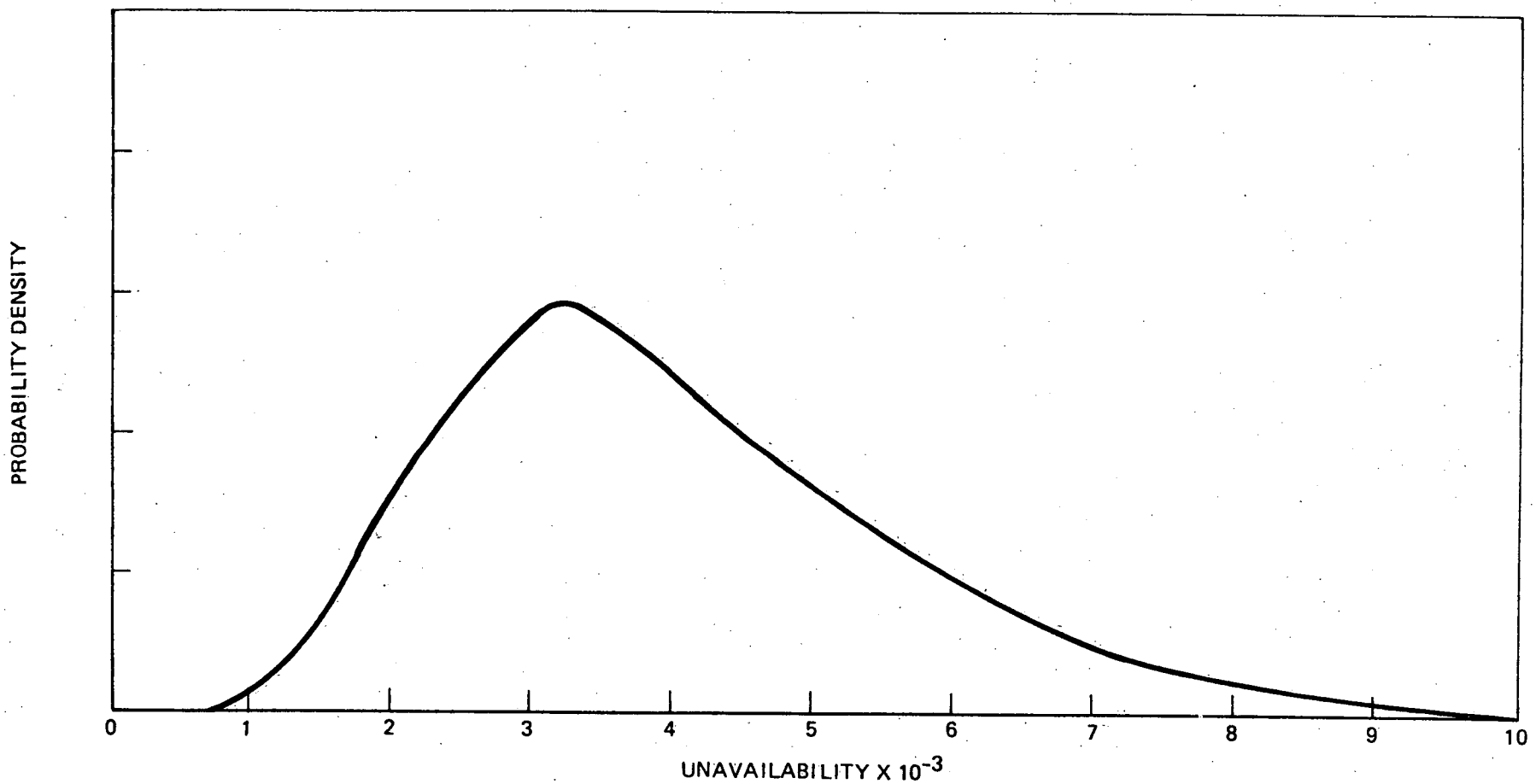

Figure 1.6.1-13. Indian Point 3 Motor-Driven Auxiliary Feedwater Pumps Unavailability Due to Maintenance

(Mean = 4.03×10^{-3})

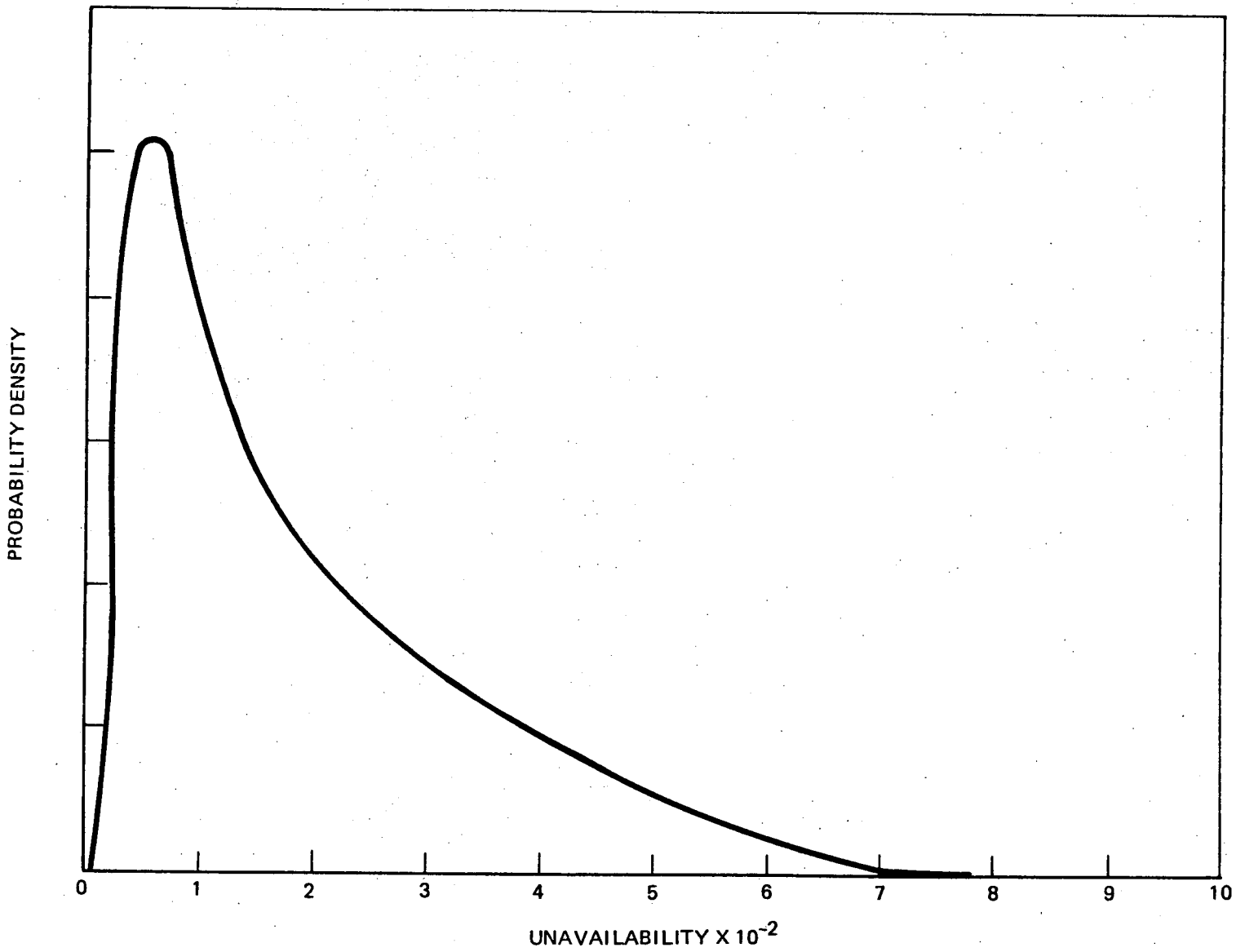

Figure 1.6.1-14. Indian Point 3 Component Cooling Pumps Unavailability Due to Maintenance

(Mean = 1.84×10^{-2})

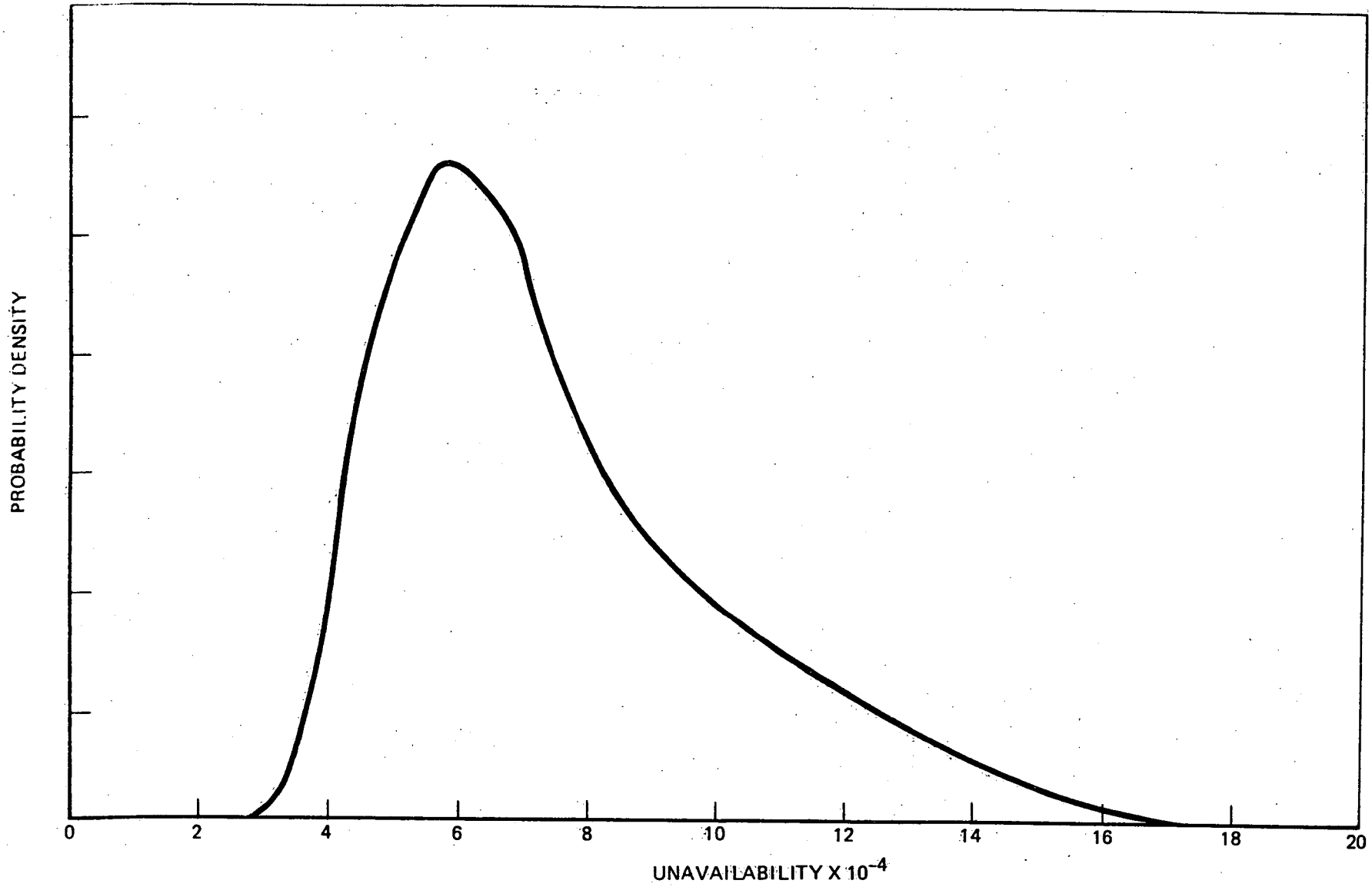

Figure 1.6.1-15. Indian Point 3 Containment Spray Pumps Unavailability Due to Maintenance

(Mean = 7.32×10^{-4})

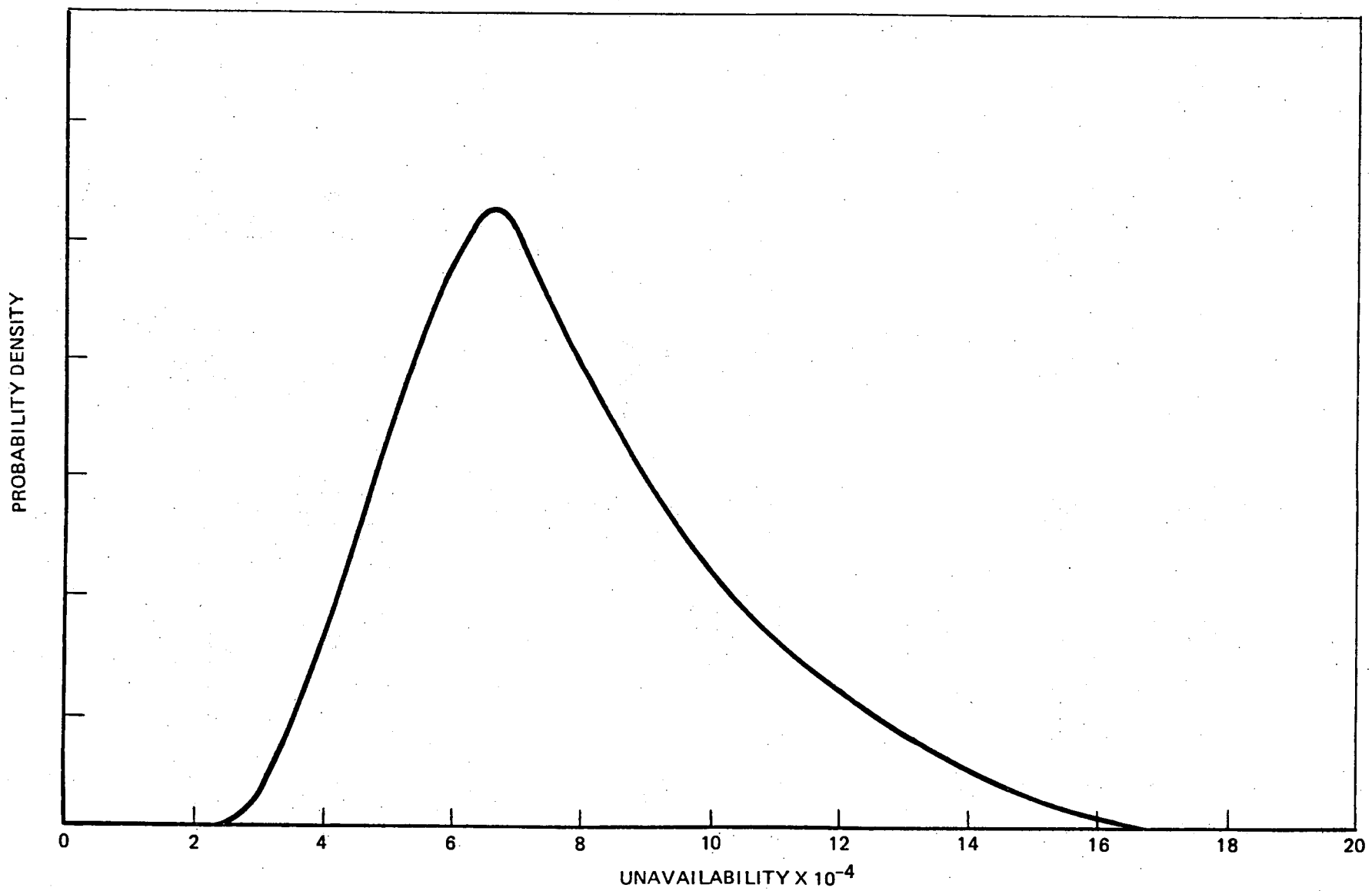

Figure 1.6.1-16. Indian Point 3 Residual Heat Removal Pumps Unavailability Due to Maintenance

(Mean - 7.63×10^{-4})

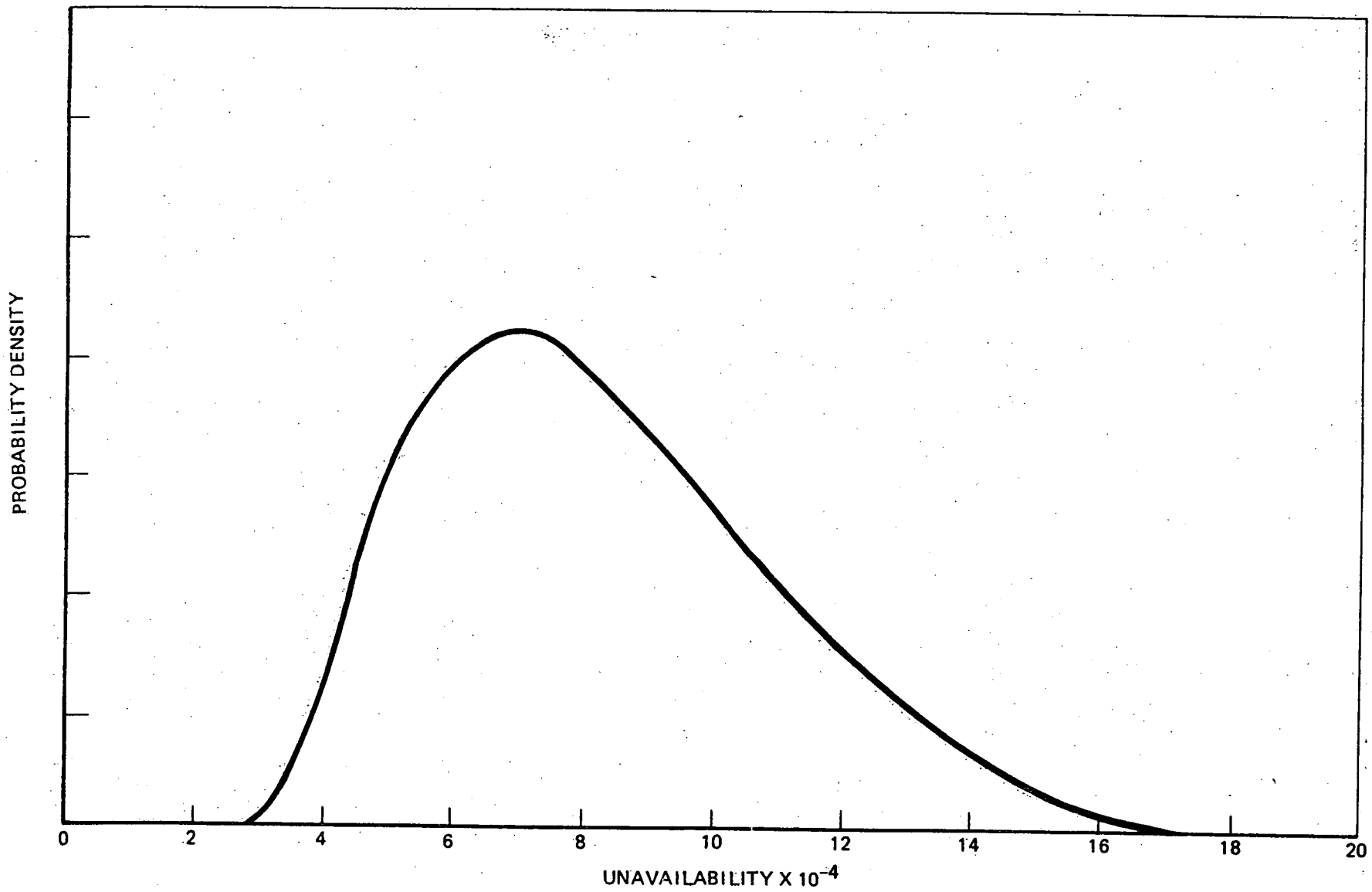

Figure 1.6.1-17. Indian Point 3 Safety Injection Pumps
Unavailability Due to Maintenance
(Mean = 8.13×10^{-4})

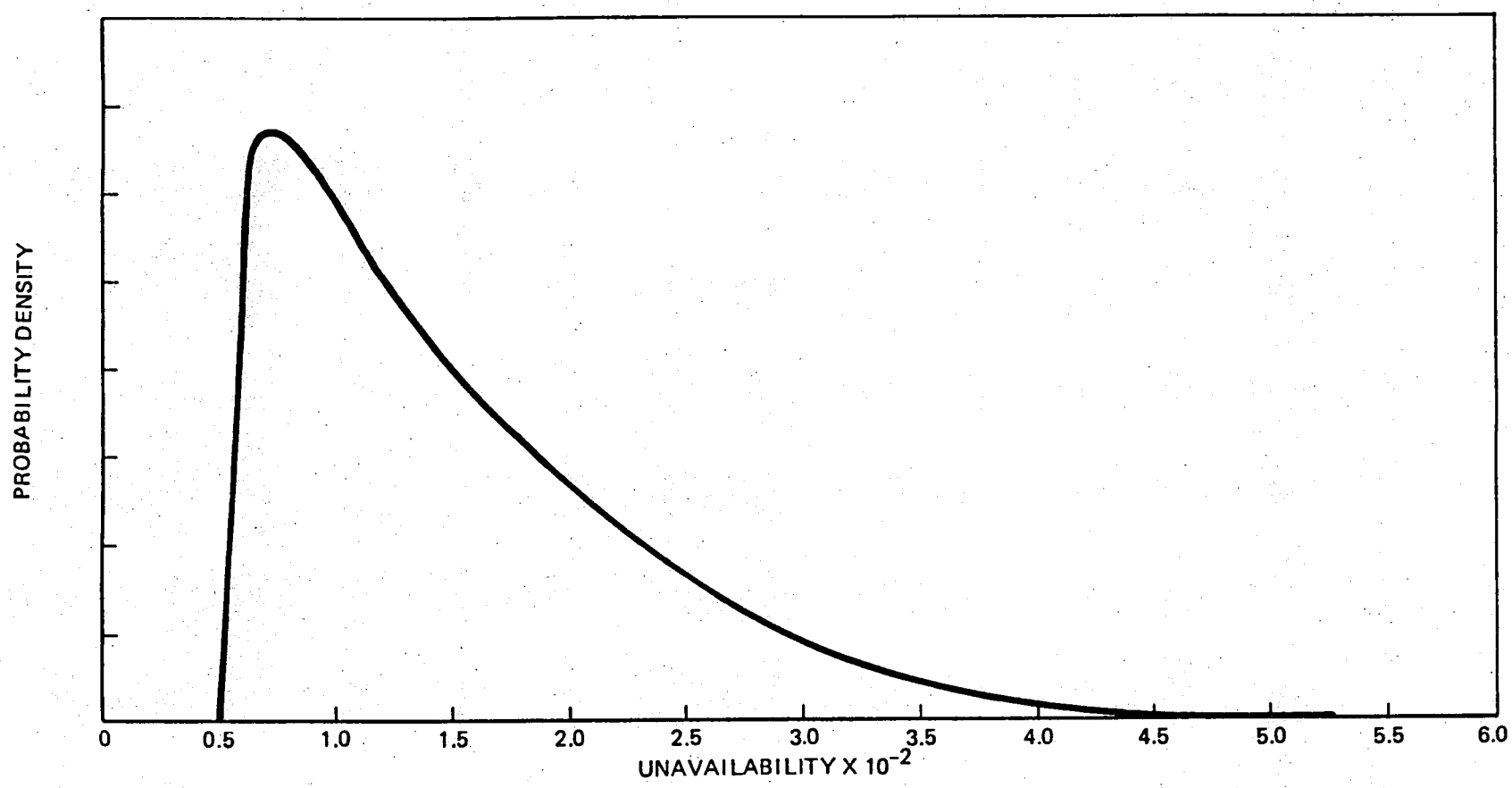

Figure 1.6.1-18. Indian Point 3 Service Water Pumps
Unavailability Due to Maintenance
(Mean = 1.47×10^{-2})

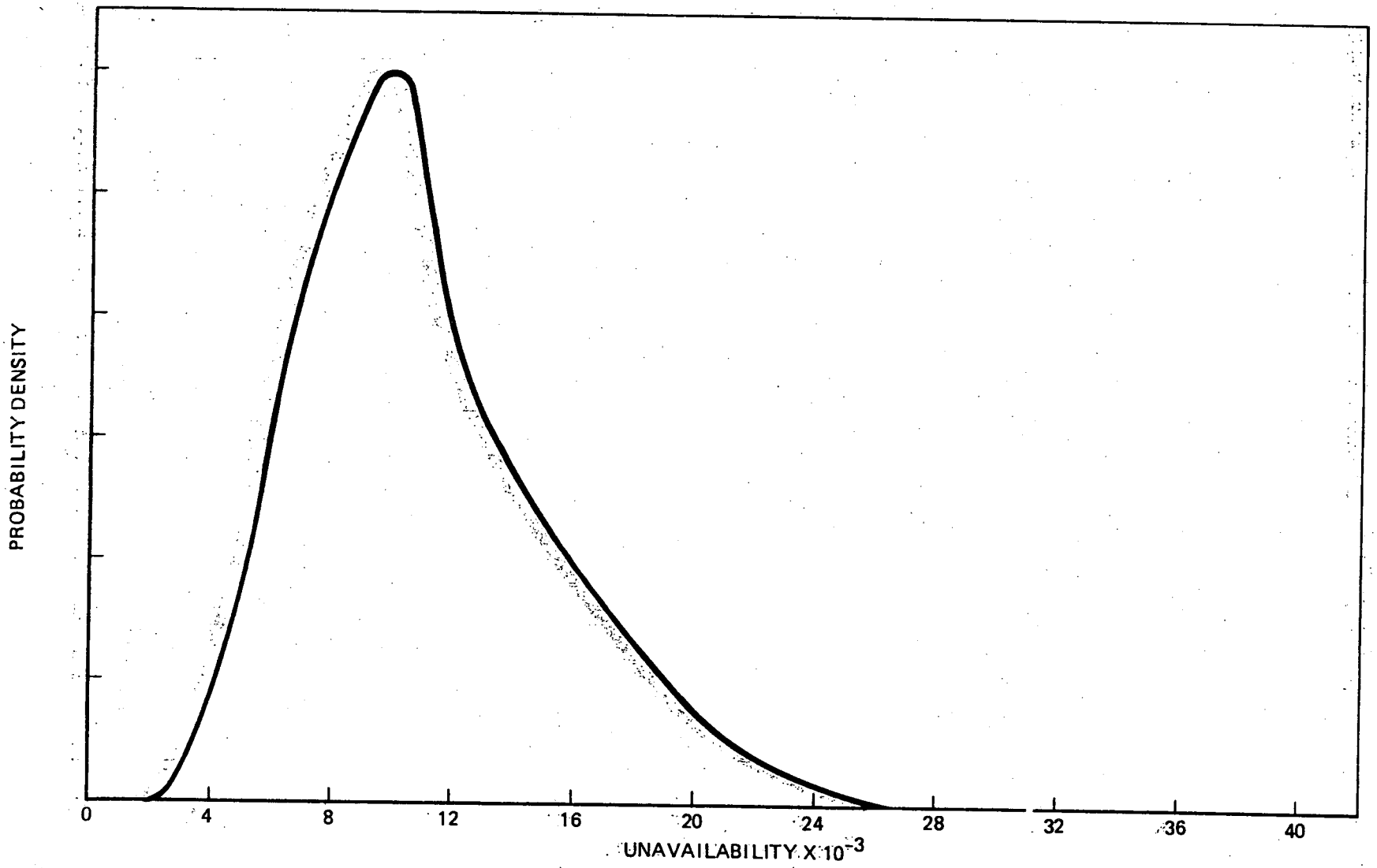

Figure 1.6.1-19. Indian Point 3 Diesel Generators
Unavailability Due to Maintenance
(Mean = 1.09×10^{-2})

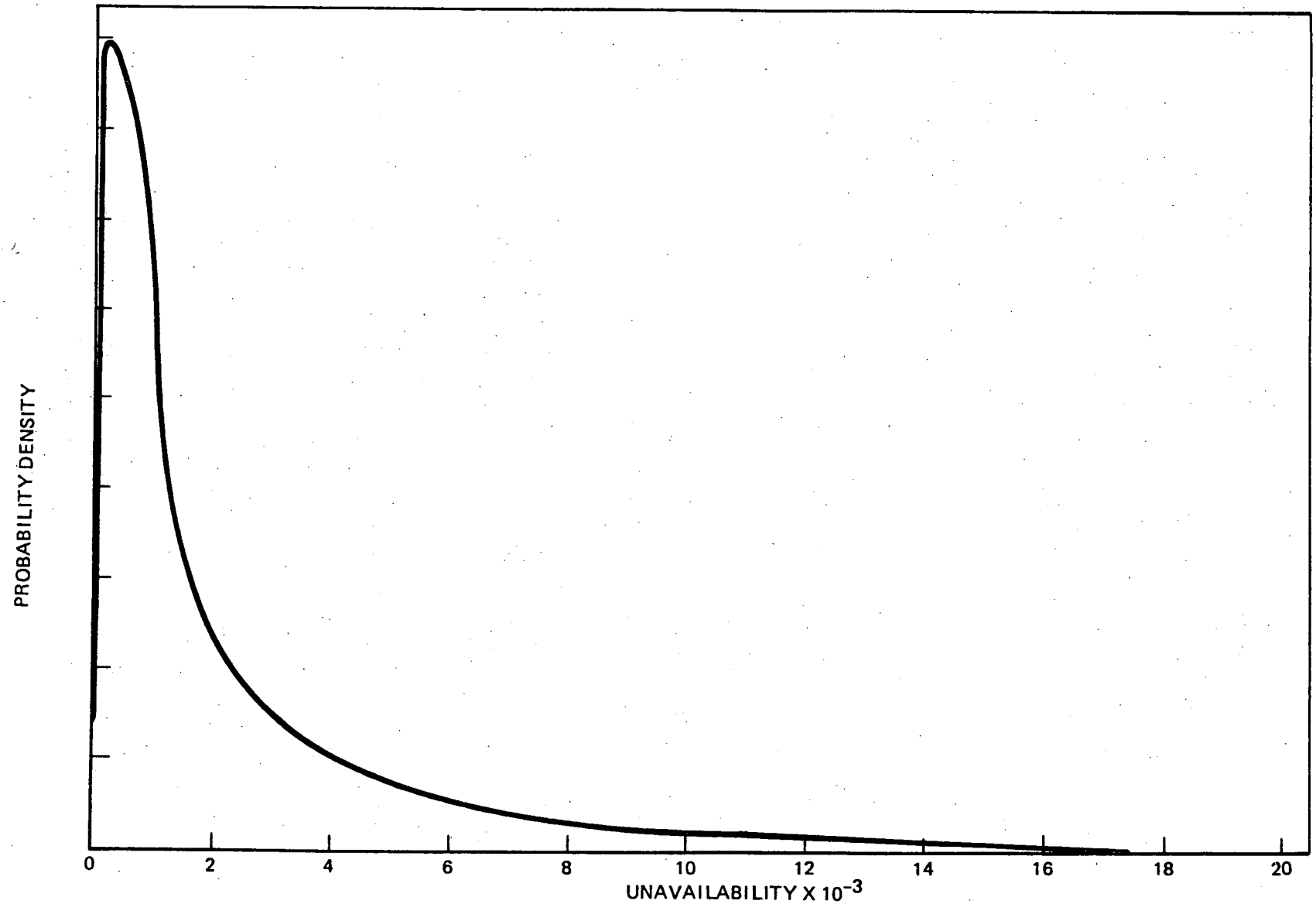

Figure 1.6.1-20. Indian Point 3 Auxiliary Component Cooling Pumps Unavailability Due to Maintenance

(Mean = 1.93×10^{-3})

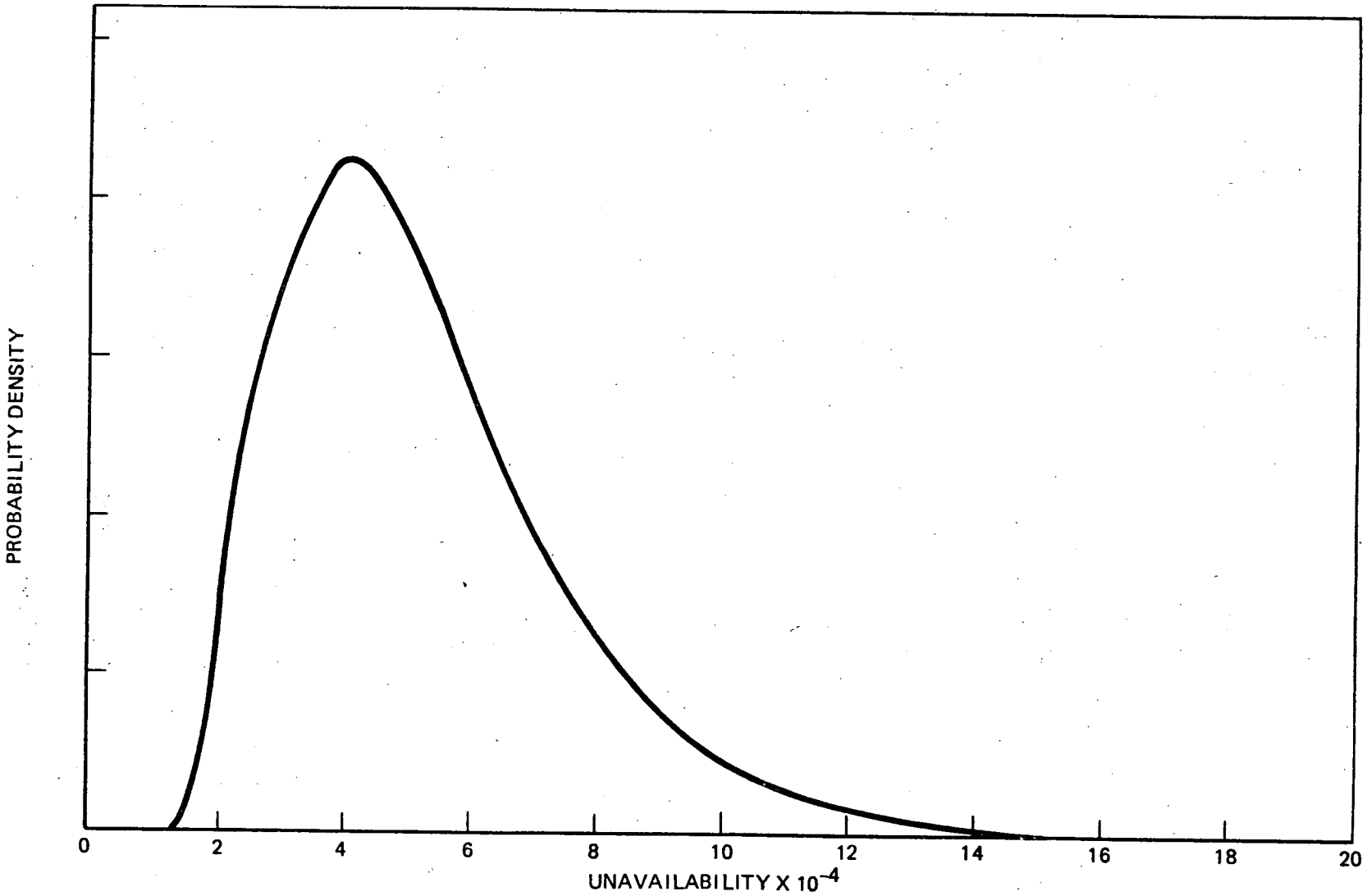

Figure 1.6.1-21. Indian Point 3 Fan Cooler Units
Unavailability Due to Maintenance
(Mean = 5.50×10^{-4})