Individual Plant Examination

for

Indian Point Unit No. 2

Nuclear Generating Station

Consolidated Edison Company of New York, Inc.

Halliburton NUS Environmental Corporation

August 1992

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SECTION 7

LIST OF ACRONYMS AND ABBREVIATIONS

ACS	Accumulator System
AFW or AFWS	Auxiliary Feedwater System
AMSAC	ATWS Mitigation System Actuation Circuitry
AOI	Abnormal Operating Instruction
ARP	Alarm Response Procedure
ARV	Atmospheric Relief Valve
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BAST	Boric Acid Storage Tank
BECCSL	LOCA Beyond ECCS Capacity
BKR	Electrical Breaker
BWR	Boiling Water Reactor
CCS or CCW	Component Cooling Water System
CP	Charging Pump
CSS	Containment Spray System
CST	Condensate Storage Tank
CET	Containment Event Tree
CPI	Core Power Excursion
COL	Check Off List
Con Edison	Consolidated Edison Company of New York, Incorporated.
CVCS	Chemical Volume Control System

LIST OF ACRONYMS AND ABBREVIATIONS
(Continued)

DBD	Design Basis Document
DCH	Direct Containment Heating
DET	Decomposition Event Tree
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System(s)
EDG	Emergency Diesel Generator
EFPY	Effective Plant Years
EOP	Emergency Operating Procedure
EPS	Electric Power System
EPRI	Electric Power Research Institute
ESFAS or SAS	Emergency Safety Features Actuation System
EVENT V	See VSEQ
FCU	Containment Air Recirculation and Filtration System (Fan Cooler Units)
FSAR	See UFSAR
GSI	Generic Safety Issue
GT	Gas Turbine
HEP	Human Error Probability
HI	Human Interaction
HNUS	Halliburton NUS and Environmental Engineering Corporation
HPIS	High Pressure Injection System

LIST OF ACRONYMS AND ABBREVIATIONS (Continued)

HRA	Human Reliability Analysis
HVAC	Heating, Ventilation and Air Conditioning System
IE	Initiating Event
IP1	Indian Point Nuclear Generating Station, Unit 1.
IP2 or IP-2	Indian Point Nuclear Generating Station, Unit 2.
IPE	Individual Plant Examination
IPPSS	Indian Point Probabilistic Safety Assessment, including Amendments 1 and 2, Con Edison and New York Power Authority 1982.
LER	Licensee Event Report
LLOCA	Large Break Loss of Coolant Accident
LPIS	Low Pressure Injection System
LOCA	Loss of Coolant Accident
LOFW	Loss of Main Feewater
LOPF	Loss of Primary Flow
LOSP	Loss of Offsite Power
MAAP	Modular Accident Analysis Program
MCC	Motor Control Center
MLOCA	Medium Break Loss of Coolant Accident
MG	Motor Generator
MSIVC	Closure of Main Steam Isolation Valve(s)
MSF	Main Steam Function

LIST OF ACRONYMS AND ABBREVIATIONS (Continued)

NSSS	Nuclear Steam Supply System
NRC	See USNRC
NUCAP+	PC Based Software For Containment Accident Progression Analysis, Halliburton NUS Corp.
NUREG 1150	Severe Accident Risks: An Assessment of Five U.S. Nuclear Power Plants, USNRC, June 1988
NUREG 1335	Individual Plant Examination Submittal Guidance, 1989
OPR	Operator Recovery
PC	Personal Computer
PDS	Plant Damage State (Note differences between Level 1 and Level 2 designation discussed in Section 3.1.6 and Table 3.4-4. The Level 1 designation is used throughout the report with the exception of Section 4)
PLG	Formerly Pickard, Lowe and Garrick Inc.
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Analysis
PTS	Pressurized Thermal Shock
PWST	Primary Water Storage Tank
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RD_{NDTO}	Reference Temperature for Return to Nil Ductility Transition
RISKMAN	PC based Risk Management Software, PLG Inc.
RPS	Reactor Protection System

LIST OF ACRONYMS AND ABBREVIATIONS (Continued)

RHR	Residual Heat Removal
RSS	Recirculation System
RXTRIP	Reactor Trip
RWST	Refuelling Water Storage Tank
SC	System Success Criteria
SG	Steam Generator
SGTR	Steam Generator Tube Rupture Accident
SI	Safety Injection
SLBIC	Main Steam Line Break Inside Containment
SLBOC	Main Steam Line Break Outside Containment
SLOCA	Small Break Loss of Coolant Accident
SOP	System Operating Procedure
SOR	Significant Occurrence Report
SOV or SORV	Stuck Open Valve (used in the context of an unmitigated SGTR to indicate isolation status of steam generator)
SWS	Service Water System
TOS	Turn Over Sheet
TTRIP	Turbine Trip
UE&C or UE	United Engineers and Constructors Corporation
UET	Unfavorable Exposure Time
UFSAR	Updated Final Safety Analysis Report for IP2

LIST OF ACRONYMS AND ABBREVIATIONS (Continued)

USI	Unresolved Safety Issue
USNRC	United States Nuclear Regulatory Commission
VENT	EDG Building Ventilation System
VSEQ	Interfacing Systems LOCA (Event V)
WASH 1400	Reactor Safety Study, USNRC 1978
WOG	Westinghose Owners Group

SECTION 1.0

EXECUTIVE SUMMARY

1.0 EXECUTIVE SUMMARY

1.1 Background and Objectives

This document reports the results of the Individual Plant Examination of the Indian Point Nuclear Generating Station Unit No 2, which has been performed by Consolidated Edison in response to Generic Letter 88-20 (Ref. 1-1) and the associated submittal guidance (NUREG-1335, Ref. 1-2).

Indian Point Unit No.2 was the subject of a detailed, comprehensive risk assessment, the Indian Point Probabilistic Safety Study (IPPSS, Ref.1-3), which was published in 1982. The IPPSS is a full scope, Level 3 Probabilistic Risk Assessment (PRA) which included consideration of both internal and external initiating events. Subsequent amendments addressing specific issues were published in 1982 and 1983. The PRA was the result of a substantial effort by a combined utility/contractor team and was subject not only to an extensive peer review process but also to an intense technical critique by the Nuclear Regulatory Commission, its contractors and several other organizations. The IPPSS was groundbreaking in many respects, and many of the methodologies used continue to be reflective of those in use today.

In 1989, the Indian Point Unit No.2 front-end (Level 1) plant model was updated to reflect changes in systems, equipment and procedures which had been implemented since the completion of the IPPSS. The plant model was recast into a three segment support state model using the RISKMAN PC-based risk management software package. As part of that effort, the data analysis was updated to include the extensive plant-specific success and failure data which had accumulated over that time period. The basic methodology was also updated in one important respect; a state-of-the art common cause model was developed using the guidance provided in NUREG\CR-4780 (Ref. 1-4). This Individual Plant Examination (IPE) builds upon those two efforts.

The current IPE effort incorporates model improvements, provides a more extensive evaluation of potential initiators, updates the Human Reliability Analysis and common cause treatments, and accounts for additional plant changes and equipment performance information since the 1989 update up through and including the 1991 refueling outage. All of the original IPPSS event trees were altered, in some cases, extensively. The basic approach, however, was essentially the same. Containment performance was also re-evaluated to address currently held phenomenological and accident progression theories and to incorporate a more modern Containment Event Tree structure. This reanalysis included extensive application of the NUREG-1150 (Ref. 1-5) results supplemented by plant specific containment transient analyses.

The objectives of an Individual Plant Examination (IPE) as defined in Generic Letter 88-20 are for the licensee:

(1) to develop an appreciation of severe accident behavior,

(2) to understand the most likely severe accident sequences that could occur at its plant,

(3) to gain a more quantitative understanding of the overall probabilities of core damage and fission product releases, and

(4) if necessary, to reduce the overall probabilities of core damage and fission product releases by modifying where appropriate, hardware and procedures that would help prevent or mitigate severe accidents.

The secondary, but no less important objectives of the study were:

(1) to expand the inhouse PRA capability within Con Edison by involving utility staff in all aspects of the examination so that in the future the insights provided by the study can be used in the plant decision making process, and

(2) to report the results of the IPE in accordance with the requirements of the IPE reporting guidelines in NUREG-1335.

Con Edison believes that the integrated result of its multi-step program of risk assessment from the inception of the original Indian Point Probabilistic Safety Study through the current effort to formally respond to the above mentioned Generic Letter, has provided us with an appreciation and understanding of the Indian Point Unit No. 2 risk profile. Consideration of the specific provisions of the Generic Letter is provided in the following sections.

1.2 Plant Familiarization

The IPE project team included two permanent Con Edison members who are located at the Indian Point Unit No.2 (IP2) site and have direct, continuing access to plant facilities, equipment, procedures and staff. Other utility staff, based both on and offsite, also participated in specific tasks. The remainder of the IPE team was made up of engineers from Halliburton NUS (HNUS) Corporation, the principle HNUS team member also having extensive prior experience at the IP2 site. The majority of the work on the project was performed at, or close to the site. The IPE team, therefore, had a wealth of knowledge regarding the IP2 plant systems and arrangement prior to beginning the study as well as immediate access to additional, current information held by the onsite Records Management group.

In the course of the study various specific plant visits and walkdowns were performed by Con Edison and HNUS engineers:

- o A plant walkdown to review the HVAC systems in the Auxiliary Building, Control Building, AFW pump room, switchgear room, etc.

- o A common cause walkdown to review the locations, environments and test and maintenance practices associated with redundant components credited in the PRA model.

- o A two day containment walkdown and data gathering effort at the beginning of the Level II analyses.

- o Formal project progress and review meetings with plant management and Independent Review Team members.

In addition numerous equipment inspections and discussions with plant operations personnel, systems engineers, operations support and training personnel were held as well as monitoring of simulator exercises. Extensive use was also made of the detailed system walkdown which had been performed during the Design Basis Documentation (DBD) project in order to validate the as-built plant design.

The identification and assembly of required information is a primary task in performing any probabilistic risk assessment. With respect to this examination, a substantial effort was undertaken to assemble the necessary information in performing the original Indian Point Unit No. 2 Probabilistic Safety Study (IPPSS). The additional effort required for the IPE was, therefore, to assemble the information needed to:

1) verify original modelling is representative of the current plant,

2) provide additional traceability, where required,

3) identify, in sufficient detail, changes to plant equipment or procedures that require modifications to the original modelling,

4) support desired additions or improvements to the existing modelling.

The major sources of information used for this effort, in addition to the original IPPSS and supporting information, were:

For Success Criteria:
- Updated Final Safety Analysis Report (UFSAR)
- Nuclear Steam Supply System (NSSS) Supplier Analysis Reports (WCAP's)
- Specific MAAP runs

For System and Component Information:
- Updated Final Safety Analysis Report (UFSAR)
- Technical Specifications
- 10CFR50.59(b) Reports
- Piping and Instrumentation Diagrams
- General Arrangement and Structural Drawings
- System Descriptions
- Design Basis Documents (DBD's)
- Valve Check-off Lists (COL's)
- Equipment Manuals

For Data Analysis (i.e. Initiating Event Frequencies & Component Success and Failure Data):
- PLG, Inc. Generic Database
- Control Room and Operator Log Sheets
- Licensee Event Reports
- Maintenance Work Orders and Work Permits
- Significant Occurrence Reports
- Test Procedures

For Human Reliability Analysis:
- Emergency Operating Procedures (EOP's)
- EOP Background Documents
- Abnormal Operating Instructions (AOI's)
- System Operating Procedures (SOP's)
- Alarm Response Procedures (ARP's)
- Available Simulator Runs

In addition, in many cases, analyses or reports addressing specific issues were utilized. In such cases, the specific information source is identified within this report or the supporting analysis files (Tier 1 or Tier 2 documentation), as appropriate.

1.3 Overall Methodology

An IPE consists of two major parts, Level 1 and Level 2. The Level 1 analysis delineates and quantifies the accident sequences leading to core damage. The result of this portion of the analysis is, therefore, a listing of core damage sequences which can be grouped according to a set of criteria which relate to the vulnerability of the containment and its protection systems to subsequent failure. These groupings are referred to as "plant damage states". The Level 2 analysis determines the likelihood, for each plant damage state evaluated in the Level 1 analysis, that containment would fail and the magnitude and composition of the radionuclide source terms that would be associated with such a failure.

The Indian Point Unit No. 2 IPE builds upon the applicable portions of the IPPSS using a PRA approach to address internal initiating events, including both a Level 1 plant damage analysis and a Level 2 containment performance analysis. The modelling approach utilized in the IPPSS and maintained in both the 1989 update and the current IPE effort is a support state approach (large event/small fault tree). For the Indian Point Unit No. 2 Level 1 effort, this approach links three event trees. The first tree represents all possible conditions of the electric power support systems. The intermediate tree represents possible conditions of other support systems such as service water and component cooling. The final tree contains all frontline accident mitigation systems and capabilities, such as auxiliary feedwater and core injection.

The systems are designated as top events on the event tree and are represented by split fractions which model the top event unavailability under various boundary conditions (e.g. specific success criteria or support system status). These split fractions are quantified through use of system equations which are boolean representations of the combinations of component (or basic event) failures which result in system failure.

The three event trees in the Level 1 analysis are linked by application of split fraction logic rules which place the appropriate initial or boundary conditions on each system consistent with the condition or state of the support system to which it is linked for each sequence. These logic rules allow direct treatment of dependencies. In the original IPPSS, the linking of event trees required a binning process at the end of each tree. This is no longer required by the RISKMAN architecture.

The final product of this linking process is a listing of all potential ways that core damage can occur (i.e. plant damage states). A binning was performed at this point to categorize the plant damage states for the purpose of analyzing results. The plant damage state results form the link between the Level 1 and Level 2 models.

The Level 2 analysis utilized a top level Containment Event Tree addressing the key events in the progression of the containment transient. Each of these events was then evaluated in further detail using Decomposition Event Trees (DET's). The DET's allow more thorough evaluation of dependencies and facilitate consideration of event specific phenomenological and equipment failure issues. The Level 2 analysis applied appropriate existing Level 2 results, most notably NUREG-1150 and its supporting analyses. In addition, plant specific MAAP runs were performed to characterize accident progression and confirm the timing of key events.

In development of the accident sequences leading to core damage or fission product release, particular attention was paid to the relationship between the system failures following a plant trip (or failure to trip) and the actions that the operators would be expected to take in accordance with the Emergency Operating Procedures (EOPs). In this way the EOPs were integrated into the analysis. The human reliability analysis was based on a careful evaluation of each EOP related to the scenario. A number of simulator observations, timings and procedure walkthroughs were made, in order to enhance the understanding of the way in which the operators used the procedures in the course of events and to assist in quantifying the failure probabilities associated with key actions. NSSS vendor analyses (WCAPs) and specific MAAP analyses were performed to determine available time windows for operator action.

Plant specific data were collected and analyzed for system maintenance frequencies and durations, initiating event frequencies and a range of component failures.

The analysis of results utilized the process provided in NUMARC 91-04 (Ref. 1-3) to categorize the systemic results obtained into functional sequences, quantify their relative significance and establish an appropriate focus and hierarchy for their consideration. In addition, various importance analyses and sensitivity studies were performed.

Finally the IPE includes a specific evaluation of the decay heat removal (DHR) function within the framwork of the plant model, thus allowing resolution of Unresolved Safety Issue A-45 as part of this response. The search for DHR vulnerabilities was then performed consistently with that for vulnerabilities associated with other mitigating functions. The insights discussed in Appendix 5 to the Generic Letter have been considered in performance of this examination.

A formal Project Plan, Quality Assurance Plan and Task Plans were developed for the project to ensure the work was well defined and coordinated, and the approriate level of documentation and review was performed. The work products were reviewed at each stage by the project team members and subjected to an independent review by personnel separate from the project team. All comments received have been addressed and retained within the appropriate analysis files.

1.4 Summary Of Major Findings

1.4.1 Core Damage Frequency Results

The mean core damage frequency (CDF) for Indian Point Unit No.2 from all internal initiating events was determined to be 3.13E-5 per year as compared to the original IPPSS mean core damage frequency for internal events of 7.9E-5 per year. An analysis was performed to evaluate the uncertainty on the core damage frequency resulting from uncertainties on the parameter values of the core damage model.

Some significant parameters of the core damage frequency distribution function are as follows:

Mean	3.13E-5 per year
5th percentile	1.63E-5 "
Median	2.76E-5 "
95th percentile	5.28E-5 "

The cutoff frequency used in quantifying the core damage frequency was 1.0E-10 per year and resulted in approximately 5000 sequences. The highest contribution comes from transient accident sequences involving loss of both primary and secondary heat removal during the injection phase. The next highest contribution comes from LOCAs with failure of core cooling in the recirculation phase. Lesser contributors include induced LOCAs following Loss of Offsite Power, LOCAs with failure of core cooling during the injection phase, Anticipated Transients Without Scram (ATWS) and Steam Generator Tube Rupture (SGTR) sequences.

The contributions, by initiator, to the IP-2 core damage frequency derived in this IPE are compared with the original IPPSS results and the results of other studies in Table 1.4-1.

Despite the inclusion of a much more comprehensive common cause failure model in the IP2 IPE (which would tend to drive the CDF upward), the overall estimate of core damage frequency when compared with the original IPPSS results has decreased. The principal reasons for this are:

(i) the adoption of a more realistic, time dependent Reactor Coolant Pump seal LOCA model which allows more credit for AC power recovery and significantly reduces the contribution from station blackout scenarios, and

(ii) the incorporation of system success criteria which more closely reflect the EOP direction given to the operators to depressurize the RCS and utilize the low head injection pumps following small and medium LOCAs with failure of high head pumps.

The Interfacing System LOCA frequency has also been reduced through a new analysis which is consistent with that performed by Brookhaven National Laboratory (under contract to the NRC), for the New York Power Authority's IP3 plant (NUREG/CR 5102, Ref. 1-6) and accounts for the probability of line rupture inside as well as outside containment due to the location of the high/low pressure pipe interface.

The contribution from general transients with successful reactor trip has increased. One reason for this is a more realistic evaluation of operator error associated with the initiation of primary bleed following failure of secondary side cooling. This analysis accounts for the plant specific characteristics which impact the time available for initiation of the bleed function by the operators. The Auxiliary Feedwater System unavailability estimate has also increased due the addition of common cause failures of the motor driven pumps.

The increase in contribution of the ATWS event reflects the use of an updated ATWS event tree model based on the more recent work performed by the Westinghouse Owners Group (WCAP 11993, Ref. 1-7).

In comparing the IP2 IPE results with other studies, the contributors are generally similar except for the higher Zion transient sequences. However on closer inspection the major contributors to that group (86% of the total CDF) comes from RCP seal LOCA induced by loss of Component Cooling or Service Water as an initiating event. Although such sequences are included in the IP2 IPE their frequency is considerably lower due to the arrangement at IP2 which allows cooling of the charging pumps, SIS and RHR pumps with city water. This capability did not exist at Zion at the time the reference PRA was performed. The availability of Gas Turbines at the IP2 site reduces the contribution of station blackout relative to other plants.

1.4.2 Containment Performance

As in the original IPPSS, the IPE results show that the Indian Point 2 Containment Building is capable of withstanding almost all core damage scenarios and is very likely to remain intact following a core damage event.

Twenty six source term release categories were developed for use in grouping the containment sequences. For convenience and clarity, the various source term classes in this work are classified into the following general release category types:

TYPE I:	Iodine, Cesium release fractions >= 0.2
TYPE II:	Iodine, Cesium release fractions >= 0.04
TYPE III:	Iodine, Cesium release fractions >= 0.002
TYPE IV:	Iodine, Cesium release fractions < 0.002
TYPE V:	No containment failure - normal leakage

The above release type ranges were fixed according to the IPE reporting requirements as well as natural breakpoints in the magnitude of the various source terms generated by the analysis.

Types I and II both exceed the magnitude of the WASH 1400 PWR-4 release category and thus according to the Generic Letter 88-20 definition are recognized as significant releases.

A comparison of the frequencies of containment failure modes from this study is made with the IPSSS and NUREG 1150 for Zion (see Table 1.4-2). As discussed below, the overall estimated frequency of a significant release at IP2 following core damage is approximately the same in this study as was found in the IPPSS.

Core melt scenarios following a steam generator tube rupture in which isolation is not achieved (e.g. a safety valve failed to reclose) were determined to be a Type I release with a calculated frequency of 3.73E-7 per year. Core melt scenarios following a steam generator tube rupture in which steam generator isolation is achieved (ie. a safety valve successfully reclosed following reduction of pressure below its setpoint) were determined to be a Type II release with a frequency of 1.25E-6 per year. The IPPSS calculated an overall core melt frequency following a SGTR initiating event of 1.3E-6 per year and assigned it a source term range which spanned both the Type I and II release categories (IPPSS Section 1.3.4.4.3). The results for the steam generator tube rupture accidents arising from this IPE study are, therefore, similar to the IPPSS result.

The IPE evaluated a third type of steam generator tube rupture scenario due to transient scenarios in which core damage occurs with the primary system at high enough temperature and pressure introduce the possibility of an induced steam generator tube rupture. This has a calculated frequency of 2.5E-7 per year and was determined to be a Type II release. The IPPSS predated consideration of this phenomenon and while there is no comparable value in the IPPSS, it would not be expected to be significantly different.

The only other contributor to Type I releases is the Interfacing Systems LOCA with a frequency of 2.68E-8 per year which is significantly lower than the IPPSS value of 3.4E-7 per year due to the additional work done by Brookhaven National Laboratory, under contract to the NRC, on this issue with specific application to the Indian Point design.

Other significant contributors to the Type II releases category are due to late containment overpressurization following, for example, small and medium LOCA with loss of all ECCS and failure of containment heat removal due to system related failures or adverse environmental conditions within containment. The frequency of late containment overpressurization releases was approximately 1.8E-6 per year in the IPPSS versus a frequency of 1.79E-6 per year for Type II late containment overpressurization releases in the IPE.

1.4.3 Vulnerabilities

No core damage or containment vulnerabilities were identified as a result of performing the IPE. This was based on application of the NUMARC Severe Accident Closure Guidelines (NUMARC 91-04, Ref. 1-8), and the performance of various sensitivity and importance reviews.

Although no specific vulnerabilities were found, many insights were gained as to the importance of specific components and proceduralized operator actions. As was done using past PRA insights, the insights from the IPE will also be incorporated into the plant decision making process.

1.4.4 Resolution of USI/GSIs

This report addresses one unresolved safety issue with respect to internal initiating events. That issue is "USI-A45, Decay Heat Removal" which is addressed in Section 3.4. The conclusion from that evaluation is that there are no vulnerabilities in this area.

No other issues have been identified at this time for resolution via this IPE report. However, the risk analysis for IP-2 may be used in the future to directly resolve or assist in resolving generic issues.

1.5 References for Section 1

1-1 Generic Letter 88-20, "IPE for Severe Accident Vulnerabilities", USNRC, Nov 23, 1988.

1-2 NUREG-1335, "Individual Plant Examination Submittal Guidance", (final).

1-3 "Indian Point Probabilistic Safety Study and Amendments 1 and 2", Consolidated Edison of Company of New York, 1982.

1-4 NUREG/CR-4780 "Procedures for Treating Common Cause Failures in Safety and Reliability Studies" January, 1988.

1-5 NUREG 1150 Vol 2, "Severe Accident Risks: "An Assessment of Five U.S. Nuclear Power Plants", June 1988.

1-6 NUREG/CR-5102 "Interfacing Systems LOCA: Pressurized Water Reactors", February 1989.

1-7 WCAP-11993 "Joint Westinghouse Owners Group/Westinghouse Program: Assessment Compliance With ATWS Rule Basis for Westinghouse PWRS", December, 1988.

1-8 NUMARC 91-04, "Severe Accident Issue Closure Guidelines", January, 1992.

1-9 NUREG/CR-4550 Vol &, Rev 1, "Analysis of Core Damage Frequency: Zion Unit No. 1 Internal Events" Sattison et al., May, 1990.

1-10 "PRA for Surry Nuclear Power Plant 1 and 2 for the Individual Plant Examination", Virgina Power, August, 1991.

1-11 "Turkey Point Plant Units 3 and 4, Probabilistic Risk Assessment, IPE Submittal:, Florida Power and Light, June 1991.

Table 1.4-1
Comparison of Core Damage Frequency by Initiator Group

Initiating Event Group	IP2 IPE	IPPSS (1982)	NUREG[1] 4550 Zion	Surry[2] IPE	Turkey[3] Point
LOCAs	1.04E-05 (33.30%)	4.4E-05	6.7E-06	2.1E-05	2.7E-05
Steam Generator Tube Rupture	1.62E-06 (5.98%)	1.3E-06	1.5E-06	1.0E-05	4.1E-06
General Transients	1.43E-05 (41.40%)	3.6E-06	3.0E-04	3.2E-05	4.4E-07
Station Blackout	4.47E-06 (14.26%)	2.96E-05	6.7E-06	8.1E-06	5.6E-05
Interfacing Systems LOCA	2.67E-08 (.09%)	3.5E-07	1.1E-07	1.6E-06	4.3E-07
Anticipated Transients w/o Scram	1.81E-06 (5.78%)	1.21E-06*	7.1E-06	3.2E-07	3.2E-06
Total CDF	3.13E-05	7.9E-05	3.4E-04	7.5E-05	1.0E-04

[1]NUREG 4550, Zion (Ref. 1-9)
[2]Surry IPE (Ref. 1-10)
[3]Turkey Point IPE (Ref. 1-11)
*The IPPSS ATWS value includes only the dominant sequences reported in IPPSS Table 8.3-9A-1.

Table 1.4-2
Comparison of Containment Failure Mode Frequencies

Containment Failure Mode	IP2 IPE	IPPSS[1]	NUREG 1150[2] (Zion)
No Containment Failure	2.65E-05	7.6E-05	2.4E-04
Late Containment Failure	2.49E-06	1.8E-06	7.8E-05
Type II	(1.79E-06)		
Type IV	(6.90E-07)		
SGTR w/oSOV Type II	1.54E-06***	*	**
Late Late Containment Failure (Type IV)	3.25E-07	**	1.5E-06
Bypass (Type I)	3.99E-07	3.5E-07	1.5E-06
SGTR w/SOV	(3.73E-07)	*	(1.4E-06)
Interfacing LOCA	(2.68E-08)	(3.5E-07)	(1.1E-07)
Early Containment Failure (Type II)	4.12E-08	2.6E-09	5.0E-06
Steam Explosion (Type I)	1.68E-10	**	**
Isolation Failure (Type II/IV)	1.47E-08	**	**
Total	3.13E-05	7.9E-05	3.3E-04

1 IPPSS Table 8.3-2A-1
2 NUREG 1150 Zion (Ref. 1-5)
* The total SGTR core damage frequency as reported in the IPPSS (Table 8.3-2A-1) was 1.3E-06. Section 1.4.2 provides additional information.
** Not reported
*** Includes contribution from SGTR initiating events and from an induced SGTRs

TABLES FOR SECTION 1

SECTION 2.0

EXAMINATION DESCRIPTION

2.0 EXAMINATION DESCRIPTION

2.1 Introduction

Indian Point Unit No.2 was the subject of a detailed, comprehensive risk assessment, the Indian Point Probabilistic Safety Study (IPPSS), which was published in 1982. The IPPSS is a full scope, Level 3 PRA which included consideration of both internal and external initiating events. Subsequent amendments addressing specific issues were published in 1982 and 1983. This study was the result of a substantial effort (totaling more than 30 man-years for Indian Point Units 2 and 3) by a combined utility/contractor team and was subject not only to an extensive peer review process but also to an intense technical critique by the Nuclear Regulatory Commission, its contractors and several other organizations. The IPPSS was groundbreaking in many respects, and many of the methodologies used continue to be reflective of those in use today.

In 1989, the Indian Point Unit No.2 front-end (Level 1) plant model was updated to reflect changes in systems, equipment and procedures which had been implemented since the completion of the IPPSS. The plant model was recast into a three segment support state model using the RISKMAN PC-based risk management software package. As part of that effort, we also updated the data analysis to include the extensive plant-specific success and failure data which had accumulated over that time period. The basic methodology was also updated in one important respect; a state-of-the art common cause model was developed using the guidance provided in NUREG/CR-4780.

The current Individual Plant Examination (IPE) builds upon those two efforts. The IPPSS contains a substantial body of information with regard to the physical plant configuration, the mitigating system and containment system functions and the dependencies between both the frontline and support systems. Since this IPE is an outgrowth of the IPPSS, the IPE report will not attempt to duplicate information already available in the IPPSS except as required to verify its continued applicability or to assure full understanding of the additional work accomplished in conformance with Generic Letter 88-20, Supplement 1.

The current IPE effort incorporates model improvements, provides a more extensive evaluation of potential initiators, updates the Human Reliability Analysis and common cause treatments and accounts for additional plant changes and equipment performance information since the 1989 update. All of the original IPPSS event trees have been altered, in some cases, extensively. The basic approach, however, is essentially the same. Containment performance is also re-evaluated to address currently held phenomenological and accident progression theories and to incorporate a more modern Containment Event Tree structure. This reanalysis includes extensive application of the NUREG-1150 results supplemented by plant specific containment transient analyses.

2.2 Compliance With Generic Letter and Supporting Material

The objectives of an Individual Plant Examination (IPE) as defined in Generic Letter 88-20 are for the licensee:

(1) to develop an appreciation of severe accident behavior,
(2) to understand the most likely severe accident sequences that could occur at its plant,
(3) to gain a more quantitative understanding of the overall probabilities of core damage and fission product releases, and
(4) if necessary, to reduce the overall probabilities of core damage and fission product releases by modifying where appropriate, hardware and procedures that would help prevent or mitigate severe accidents.

Con Edison believes that the integrated result of its multi-step program of risk assessment from the inception of the original Indian Point Probabilistic Safety Study through the current effort to formally respond to the abovementioned Generic Letter, has provided us with the desired appreciation and understanding of the Indian Point Unit No. 2 risk profile. Consideration of the specific provisions of the Generic Letter is provided in the following sections.

2.2.1 Examination Process

To derive maximum benefit from the overall IPE/PRA process, the project was designed as a joint Con Edison/Halliburton NUS Corporation effort and utility personnel were involved, to varying extents, in all aspects of the effort. The utility IPE team included two full time members and several additional members who participated in specific tasks. The principal utility participants brought to the effort statistical and engineering expertise as well as extensive direct experience in plant operations, safety analyses and licensing requirements. The utility team members are part of the plant organization, are permanently located at the plant site and have direct continuing access to plant systems and components. Most of the work on the project was performed at, or near the plant site.

To ensure the accuracy and validity of the work performed under the IPE, an in-house independent review was included in the project scope. This effort took full advantage of the Independent Safety Review Section, located at the plant site, with additional assistance from other company personnel, which were not part of the IPE team, where such additional review was deemed to be of value. The personnel who provided independent review for this study have expertise in operations, engineering, safety and risk analysis.

The independent review included:

- o Initiating Events
- o Success Criteria
- o Modelling Assumptions
- o Screening Analyses
- o Level 1 Event Trees
- o System Models
- o Containment Event Trees
- o Containment Strength Analysis
- o Source Term Analysis
- o Supporting Analyses
- o Results

2.2.2 External Events

As described in Con Edison's initial October 29, 1989 response (Ref. 2-1) to the Generic Letter and accepted by NRC correspondence dated January 30, 1990 (Ref. 2-2), documenting review of that response, the scope of the Indian Point IPE does not include external events or internal flooding, both of which will be addressed as a separate coordinated effort.

2.2.3 Method of Examination

As described earlier, the IPPSS is a Full Scope Level 3 PRA, which includes both internal and external initiating events. Since Generic Letter 88-20, Supplement 1 does not seek to address external events or extend to consequence analysis, the Indian Point Unit No. 2 IPE builds upon the applicable portions of the IPPSS using a PRA approach to address internal initiating events, including both a Level 1 plant damage analysis and a Level 2 containment performance analysis. We believe that the methods used for the IPPSS and this IPE are consistent with those found in the guidance documents cited in the Generic Letter. The containment performance analysis is consistent with the guidance provided in Appendix 1 of the generic letter and includes consideration of the insights provided in Supplement 3 to the generic letter. The IPE reflects the plant configuration as it existed at the start of the current operating cycle in mid-1991 (i.e. up to the end of the last refueling outage).

2.2.4 Resolution of Unresolved Safety Issue A-45

The IPE includes specific evaluation of the decay heat removal (DHR) function within the framwork of the plant model, thus allowing resolution of Unresolved Safety Issue A-45 as part of this response. The search for DHR vulnerabilities is then performed consistently with that for vulnerabilities associated with other mitigating functions. The insights discussed in Appendix 5 to the Generic Letter have been considered in performance of this examination.

2.2.5 PRA Benefits

The approach taken for Indian Point Unit No. 2 is completely consistent with the discussion provided in this section of the generic letter. The results and insights provided by the original IPPSS and our previous update have already been used both qualitatively and quantitatively to support risk management of short and long term activities at the plant.

2.2.6 Severe Accident Sequence Selection

A ranking has been performed of both plant damage and containment release sequences and is provided in Section 3.4. The sequences provided meet or exceed the reporting requirements described in Appendix 2 to the generic letter and further delineated in Section 2.1.6 of NUREG-1335. The documentation needed to fully understand the progression of events represented by those sequences is also provided in Section 3.1 of this report.

2.2.7 Accident Management

Recognizing that the IPE is part of an overall effort to address the Severe Accident Issue, the IPE has been performed and the results of the IPE examined in light of its potential use in, or application to accident management. Where the potential exists for achieving significant risk reduction through consideration in the development of accident management strategies, that potential has been specifically noted. Since accident management is still in development, however, such information is provided to assure that it is readily available at the appropriate point in that development.

2.2.8 Documentation of Examination Results

The Indian Point Unit No. 2 IPE has adopted the two tier approach to documentation discussed in the generic letter. This IPE Report represents the first tier and is intended to address the documentation requirements specified in Appendix 4 to the generic letter. The second tier consists of several forms of documentation. These include the Level 1 and 2 risk models which exist in the RISKMAN and NUCAP+ software, the analysis files which contain all the supporting and reference information, the original Indian Point PRA

(IPPSS) and which documents the Level 1 update performed in 1989. This report follows the format which is recommended in NUREG-1335, as closely as possible.

2.3 General Methodology

The Indian Point Unit No. 2 IPE builds upon the applicable portions of the IPPSS using a PRA approach to address internal initiating events, including both a Level 1 plant damage analysis and a Level 2 containment performance analysis. The modelling approach utilized in the IPPSS and maintained in both the 1989 update and the current IPE effort is a support state approach. For the Indian Point Unit No. 2 Level 1 effort, this approach links three event trees. The first tree represents all possible conditions of the electric power support systems. The intermediate tree represents possible conditions of other support systems such as service water and component cooling. The final tree contains all frontline accident mitigation systems and capabilities.

The systems are designated as top events on the event tree and are represented by split fractions which describe the various system configurations which must be considered. These split fractions are quantified through use of system equations which are boolean representations of the combinations of component (or basic event) failures which result in system failure.

The three event trees in the Level 1 analysis are linked by application of split fraction logic rules which place the appropriate initial or boundary conditions on each system consistent with the condition or state of the support system to which it is linked for each sequence. These logic rules allow direct treatment of dependencies. In the original IPPSS, the link of event trees required a binning process at the end of each tree. This is no longer required by the RISKMAN architecture.

The final product of this linking process is a listing of all potential plant damage states. A binning was performed at this point to categorize the plant damage states for the purpose of analyzing results. The plant damage state results were then linked to the Level 2 model.

The Level 2 analysis utilized a top level Containment Event Tree addressing the key events in the progression of the containment transient. Each of these events was then evaluated in further detail using using Decomposition Event Trees (DET's). The DET's allow more thorough evaluation of dependencies and facilitate consideration of event specific phenomenological and equipment failure issues. The Level 2 analysis applied appropriate existing Level 2 results, most notably NUREG-1150 and its supporting analyses. In addition, plant specific MAAP runs were performed to characterize accident progression and confirm the timing of key events.

In development of the accident sequences leading to core damage or fission product release, particular attention was paid to the relationship between the system failures following a plant trip (or failure to trip) and the actions that the operators would be expected to take in accordance with the Emergency Operating Procedures (EOPs). In this way the EOPs were integrated into the analysis. The human reliability analysis was based on a careful evaluation of each EOP related to the scenario. A number of simulator observations, timings and procedure walkthroughs were made, in order to enhance the understanding of the way in which the operators used the procedures in the course of events and to assist in quantifying the failure probabilities associated with key actions. NSSS vendor analyses (WCAPs) and specific MAAP analyses were performed to determine available time windows for operator action.

Plant specific data were collected and analyzed for system maintenance frequencies and durations, initiating event frequencies and a range of component failures.

The analysis of results utilized the process provided in NUMARC 91-04 (Ref. 2-3) to categorize the systemic results obtained into functional sequences, quantify their relative significance and establish an appropriate focus and hierarchy for their consideration. In addition, various importance analyses and sensitivity studies were performed.

Finally the IPE includes a specific evaluation of the decay heat removal (DHR) function within the framwork of the plant model, thus allowing resolution of Unresolved Safety Issue A-45 as part of this response. The search for DHR vulnerabilities was then performed consistently with that for vulnerabilities associated with other mitigating functions. The insights discussed in Appendix 5 to the Generic Letter have been considered in performance of this examination.

A formal Project Plan, Quality Assurance Plan and Task Plans were developed for the project to ensure the work was well defined and coordinated, and the approriate level of documentation and review was performed. The work products were reviewed at each stage by the project team members and subjected to an independent review by personnel separate from the project team. All comments received were addressed and retained within the appropriate analysis files.

2.4 Information Assembly

The identification and assembly of required information is a primary task in performing any probabilistic risk assessment. With respect to this examination, a substantial effort was undertaken to assemble the necessary information in performing the original Indian Point Unit No. 2 Probabilistic Safety Study (IPPSS). The additional effort required for this study was, therefore, to assemble the information needed to:

1) verify the currency of the original modelling,

2) provide additional traceability, where required,

3) identify, in sufficient detail, changes to plant equipment or procedures that require modifications to the original modelling,

4) support desired additions or improvements to the existing modelling

The major sources of information used for this effort, in addition to the original PRA and supporting information, were:

For Success Criteria:
- Updated Final Safety Analysis Report (UFSAR)
- NSSS Supplier Analysis Reports (WCAP's)
- Specific MAAP runs

For System and Component Information:
- Updated Final Safety Analysis Report (UFSAR)
- Technical Specifications
- 10CFR50.59(b) Reports
- Piping and Instrumentation Diagrams
- General Arrangement and Structural Drawings
- System Descriptions
- Design Basis Documents (DBD's)
- Valve Check-off Lists (COL's)
- Equipment Manuals

For Data Analysis(i.e. Initiating Event Frequencies & Component Success and Failure Data):
- PLG, Inc. Generic Database
- Control Room and Operator Log Sheets
- Licensee Event Reports
- Maintenance Work Orders and Work Permits
- Significant Occurrence Reports
- Test Procedures

For Human Reliability Analysis:
- Emergency Operating Procedures (EOP's)
- EOP Background Documents
- Abnormal Operating Instructions (AOI's)
- Standard Operating Procedures (SOP's)
- Alarm Response Procedures (ARP's)
- Available Simulator Runs

In addition, in many cases, analyses or reports addressing specific issues were utilized. In such cases, the specific information source is identified within the Tier 1 or 2 documentation as appropriate.

2.4.1 Plant Familiarization

The IPE project team included two permanent Con Edison members who are located at the Indian Point Unit No.2 (IP2) site and have direct, continuing access to plant facilties, equipment, procedures and staff. Other utility staff, based both on and offsite, also participated in specific tasks. The remainder of the IPE team was made up of engineers from Halliburton NUS (HNUS) Corporation, the principle HNUS team member also having extensive prior experience at the IP2 site. The majority of the work on the project was performed at, or close to the site. The IPE team, therefore, had a wealth of knowledge regarding the IP2 plant systems and arrangement prior to beginning the study as well as immediate access to additional, current information held by the onsite Records Management group.

In the course of the study various specific plant visits and walkdowns were performed by Con Edison and HNUS engineers:

- o A plant walkdown to review the HVAC systems in the Auxiliary Building, Control Building, AFW pump room, switchgear room, etc.

- o A common cause walkdown to review the locations, environments and test and maintenance practices associated with redundant components credited in the PRA model.

- o A two day containment walkdown and data gathering effort at the beginning of the Level II analyses.

- o Formal project progress and review meetings with plant management and Independent Review Team members.

In addition, numerous equipment inspections and discussions with plant operations personnel, systems engineers, operations support and training personnel were held as well as monitoring of simulator exercises. Extensive use was also made of the detailed system walkdown which had been performed during the Indian Point Unit No. 2 Design Basis Documentation (DBD) project in order to validate the as-built plant design.

2.4.2 Plant Layout and Containment Building Information

Indian Point Station Unit No. 2 is a four-loop, pressurized water reactor with a Westinghouse designed Nuclear Steam Supply System. The unit is rated at 3071.4 MwTh and is enclosed in a steel reinforced, cylindrical, "large dry" Containment structure. The balance of plant (BOP) systems were designed by United Engineers and Constructors (UE&C) Corporation.

The design and configuration of important safety systems including those which influence containment response are described in Section 1.3 of the IPPSS with additional detail available in the abovementioned information sources. The information in the IPSSS is supplemented, and where applicable, updated in Section 3 of this report. An analysis of Containment structural capability is provided in Appendix 4.4.1 of the IPPSS and was utilized in the IPE backend analysis which is described in Section 4 of this report.

A summary of the major design features at Indian Point Unit No. 2 is provided in Table 2.1.

2.4.3 Probabilistic Risk Analyses Reviewed and Insights Derived

As previously stated, this IPE analysis builds upon the extensive work performed in the Indian Point Probabilistic Safety Study (IPPSS) which was performed for both Indian Point Units 2 and 3. The full Con Edison/HNUS team is familiar with the results and insights contained in those studies, and have fully factored them into the IPE effort. Other studies for plants with similar designs such as Zion (Zion Probabilistic Safety Study, NUREG-1150), Surry (IPE, NUREG-1150) and Seabrook (Seabrook Station Probabilistic Safety Assessment, IPE) have also been reviewed. Included among the insights obtained which are relevant to internal initiating events is the sensitivity to treatment of RCP seal LOCA's, the significance of support systems and the importance in certain scenarios of timely and effective operator action (e.g. following steam generator tube rupture or loss of secondary cooling). In the Level 2 area, insights include the robustness of the large, dry containment design, the relative significance of primary system pressure prior to vessel failure, the importance of providing water to the core even after core damage and the large uncertainties in much of the accident progression phenomena.

2.5 References for Section 2

2-1 Letter dated October 27, 1989, from S Bram (Con Edison) to Document Control Desk (USNRC), Response to NRC Generic Letter 88-20 and Supplement 1 (60-day Response)

2-2 Letter dated January 30, 1990, from D. Brinkman (NRC) to S. Bram (Con Edison), Review of 60 Day Response to Generic Letter 88-20 Individual Plant Examination (IPE) (TAC No. 7442).

2-3 NUMARC 91-04 "Severe Accident Issue Closure Guidelines", January, 1992.

TABLES FOR SECTION 2

TABLE 2.1-1 MAJOR DESIGN FEATURES FUNCTION	 DESIGN FEATURES
Emergency Core Cooling - High Pressure	Three SIS Pumps for High Pressure Injection and Recirculation. The SIS Pump shutoff head is below the Pressurizer PORV Setpoint
Emergency Core Cooling - Intermediate Pressure	Four Accumulators
Emergency Core Cooling - Low Pressure	Two RHR Pumps for Low Pressure Injection. Two Recirculation Pumps (located inside Containment) for Low Pressure Recirculation with backup capability from the RHR Pumps.
Containment Pressure Protection	Two Containment Spray Pumps (with spray additive) and Five Fan Cooler Units
Primary Side Decay Heat Removal	Two RHR Pumps Through two Heat Exchangers
Secondary Side Decay Heat Removal	Four Steam Generators supplied from two motor driven Auxiliary Feedwater Pumps (each feeding two SG's) and one Turbine Driven Pump (feeding all four SG's)
Emergency AC Power	Three Emergency Diesel Generators feeding the four 480V Buses which feed safeguards equipment. Three Gas Turbine Generators (two with full blackstart capability) available for AC Power Recovery on loss of normal and emergency AC power
DC Power	Four DC buses Normal feed: Battery chargers fed from normal AC power sources. Emergency feed: Either battery chargers fed from Diesels or four Battery Banks

SECTION 3.0

FRONT END ANALYSIS

3.0 FRONT END ANALYSIS

Section 3 of this report describes the approach used to identify and quantify the ways in which core damage can occur at IP2 and define the the status of the plant systems important to mitigating a radioactive release during and after core damage. The various topics discussed include:

Section 3.1: Accident Sequence Delineation - This section describes the identification and categorization of initiating events, mitigating systems success criteria, event tree development and accident sequence categorization.

Section 3.2: Systems Analysis - This section describes the development and quantification of models created to represent the response of systems to the spectrum of initiating events.

Section 3.3: Sequence Quantification - This section describes the development and use of generic and IP2 plant specific data to quantify initiating event frequencies, component unavailability parameters and pre and post-accident human error probability. This section also presents the common cause treatment included in the IPE and provides the sequence/plant damage state quantification.

Section 3.4: Results Analysis and Screening - This section includes the determination of reportable sequences and vulnerability evaluations including decay heat removal. (In accordance with the IPE submittal guidance both Level I and Level II issues are addresed in Section 3).

SECTION 3.1

ACCIDENT SEQUENCE DELINEATION

3.1 Accident Sequence Delineation

3.1.1 Initiating Events

An initiating event is either (1) an event which occurs while the plant is at power, resulting in a perturbation that potentially challenges the core thermal design criteria thereby necessitating actuation of the reactor protection system (RPS) and insertion of control rods, or (2) a perturbation resulting directly from insertion of the control rods as a result of automatic or manual reactor trip signals. Such events will require the continued operation, or initiation of the systems required to maintain decay heat removal from the fuel, the Reactor Coolant System and the Containment Building and thus prevent core damage and radionuclide release to the environment. Events occurring during plant shutdown such as a refueling outage are specifically excluded from this analysis. Also excluded at the present time are the all external events (including internal flooding) which will be addressed as part of the IPEEE response.

The IPE study utilized the same initiating event categorization scheme developed for IP-2 in the IPPSS (Section 1.1), although the actual generic and plant specific trip data has been updated once in 1988 and again as part of this study, as discussed in Section 3.3. Furthermore, specific supplemental analyses have been performed to identify each of the support systems at IP2 and determine whether the impact of failure during plant operation can pose a significant risk by causing an initiating event, degrading an accident mitigating system or both. The effects were both qualitatively and quantitatively screened, taking into account the timing of events and the potential for operator recovery actions. The following systems/subsystems were identified and addressed:

- Station Auxiliary Transformers
- 6.9kV Buses 5, 6, 2 and 3
- All 480V AC Buses
- All 118V AC Instrument Buses
- All 125V DC Buses
- ESFAS Trains
- Essential Service Water
- Non-essential Service Water
- IP1 River Water System
- Component Cooling Water System
- Instrument Air System
- HVAC Systems
  - Central Control Room
  - Primary Auxiliary Building
  - Electrical Switchgear Room
  - Auxiliary Feedwater Pump Room
  - Turbine Hall
  - Cable Spreading Room/Electrical Tunnel
- City Water System

Of the above listed systems, only the loss of Service Water and Component Cooling were explicitly modeled as initiating events in the IPSSS. As a result of this analysis, the loss of DC Power Buses 21 and 22 and Loss of 6.9 kV Buses 2 and 3 were added to the the list of initiating events already quantified.

The final list of initiating event groups is shown below:

Large LOCA (LLOCA)

The large LOCA tree includes all openings greater than 6 inches in diameter up to a double ended RCS pipe break. The initiating events are:

a. Pipe rupture, cracks, etc.
b. Valve failures.
c. Vessel failure.
d. Other openings in the primary system greater than 6 inches in diameter up to a double ended RCS pipe rupture for whatever reason.

Medium LOCA (MLOCA)

The medium LOCA includes all openings from the primary system of 2 to 6 inches in diameter. The initiating events are:

a. Pipe rupture, cracks, etc.
b. Safety and relief valve failures (multiple).
c. Other valve failures.
d. Other openings in the primary system within this size range.

Small LOCA (SLOCA)

The small LOCA includes all openings from the primary less than 2 inches in diameter. Steam generator tube rupture is considered separately. The initiating events are:

a. Pipe breaks, cracks, etc.
b. Safety or relief valve failures.
c. Valve failures.
d. Control rod drive mechanism failures.
e. Other openings from the primary within this size range.

Steam Generator Tube Rupture (SGTR)

The steam generator tube rupture is a release of primary inventory to the secondary system. The dynamics of the event are quite different from the LOCA events just described.

a. Single steam generator tube rupture from any cause.

Steam Break (Steam Release) Inside Containment (SLBIC)

This initiating event is a steam or a feedwater break in the secondary system that is large enough to actuate the safety injection system. The initiating events are:

a. Main Steamline break inside containment.
b. Feedwater line break inside containment.
c. Any other substantial steam loss inside containment.

Feedwater break is included as part of this tree because the effects on the steam generator and some of the actuation signals are similar to those of the steam break. From a response standpoint it is considered a subset of the steam break.

Steam Break (Steam Release/Demand) Outside Containment (SLBOC)

This initiating event includes any excessive steam demand from outside the containment. The initiating events include:

a. Steamline breaks outside containment.
b. Turbine-generator overload or sudden load increase.
c. Steam dump valves failing open.
d. Other steam losses outside containment.

Loss of Main Feedwater (LOFW)

This initiating event involves the loss of main feedwater to one or more steam generators from causes outside containment. The initiating events include:

a. Feedwater line break upstream of the isolation/check valves.
b. Loss/reduction of feedwater flow to one steam generator.
c. Loss/reduction of feedwater flow to all steam generators.
d. Feedwater flow instability--operator causes.
e. Feedwater flow instability--mechanical causes.
f. Loss of condensate pumps.
g. Excessive Condenser leakage.
h. Other excessive secondary side leakage.

Closure of a Main Steam Isolation Valve (Partial Loss of Steam Flow) (MSIVC)

This initiating event includes closure of one of the four main steam isolation valves. It is considered separately from other events because the response characteristics do not match the other secondary side events that were modeled. It constitutes a lesser challenge than most other secondary side initiating events. Simultaneous multiple MSIV trips are very unlikely and can be grouped with this tree (two or three failures) or the Turbine Trip (all four MSIVs trip).

The initiating events include:

a. Spurious closure of a single MSIV.
b. Simultaneous spurious closure of two or three MSIVs.
c. Partial closure of one or more MSIVs.
d. Any other substantial loss of steam flow.

Loss of Reactor Coolant Flow (LOPF)

This initiating event includes any event that causes a loss of flow in single or multiple reactor coolant loops. The initiating events include:

a. Reactor coolant pump trip.
b. Reactor coolant pump locked rotor.
c. Flow blockage.
d. Flow coastdown in 1, 2, 3 or 4 loops.

Core Power Excursion (CPI)

This initiating event covers a large number of events that could cause the core to increase power while in hot shutdown or at power. The initiating events include:

a. Boron dilution accidents.
b. Rod ejection.
c. Inadvertant rod withdrawal.
d. Control rod disassembly.
e. Fuel or burnable poison/core geometry change.
f. Cold water addition.
g. Excessive load increase.
h. Other positive reactivity additions.

Turbine Trip (TTRIP)

This initiating event is used to describe events whose effects on the RCS are initiated by a turbine trip. The initiating events included are:

a. Closure of all main steam isolation valves.
b. Increase in feedwater flow in one steam generator.
c. Increase in feedwater flow in all steam generators.
d. Loss of condenser vacuum.
e. Loss of circulating water.
f. Throttle valve closure.
g. Generator trip or generator caused faults.
h. Turbine-generator accidents--miscellaneous.
i. Turbine trips.

To account for its unique impacts, turbine trip with loss of service water (LOSW) was evaluated separately using the general transient event tree structure.

Reactor Trip (RXTRIP)

This event is initiated by a reactor trip. The events included are:

a. Control rod drive mechanism problems and/or rod drop.
b. High or low pressurizer pressure.
c. High pressurizer level.
d. Spurious automatic trip--no transient condition.
e. Automatic/manual trip--operator error.
f. Manual trip resulting from false signal.
g. Spurious trip--cause unknown.
h. Primary system pressure, temperature, power imbalance.
i. Loss of power to necessary plant systems.
j. Loss of instrument air.
k. Spurious safety injection.

Several special causes of reactor trips which have additional functional impacts were evaluated separately:

a. Loss of Component Cooling Water (LOCCW).
b. Loss of DC bus D21 (LODC21).
c. Loss of DC bus D22 (LODC22).
d. Loss of 6.9 kV bus 2 (LO692)
e. Loss of 6.9 kv bus 3 (LO693)

Loss of Offsite Power (LOSP)

This event is a loss of offsite power from the 138 kV and 13.8 kV feeders to the to the IP2 plant.

Failure of Reactor to Trip (ATWS)

In evaluating all of the previous initiating event trees, reactor trip is assumed to be successful. This event tree models the potential for an anticipated transient without SCRAM (ATWS) event to occur following any plant transient or LOCA event (except Large LOCA, LOCA Beyond ECCS Capacity and V Sequence where the reactivity control provided by the reactor trip is not required) and subsequent accident mitigation.

LOCA Beyond ECCS Capacity (BECCSL)

This initiating event is included for completeness to model the extremely remote possibility of breach of the reactor pressure vessel or multiple RCS pipes, leading to a LOCA which is beyond the capacity of the ECCS pumps and therefore cannot be mitigated prior to core damage.

Interfacing Systems LOCA (VSEQ)

This event represents an unisolated break located outside containment in a line which connects directly to the RCS.

3.1.2 Success Criteria

The success criteria for an initiating event are the minimal number of systems, or system trains, that are required to function to maintain adequate heat removal from the core and containment; ultimately establishing long term stable conditions and preventing core damage.

The specific bases for the success criteria adopted in the the original IPPPS study are not explicitly referenced in the IPPSS document. The NRC recognized this point in their review of the IPPSS (NUREG/CR-2934, Ref 3.1-1) but concluded that the criteria used appeared to be reasonable and consistent with that used in other PRAs.

Since the original PRA analysis was performed, the IP2 licensed power rating has been increased by 11.5% to 3083.4 MWT, and thus certain aspects of the accident analysis upon which the original SC was based, may have been impacted. Other recent analyses relating to the plant's ultimate heat sink capabilities and diesel generator loading have also impacted the success criteria.

The objective of the success criteria analysis performed as part of the IPE task were therefore to:

1) Verify the existing SC are realistic (or conservative) and appropriate, and document the bases, or provide a justifiable alternative and document the bases.

and

2) Where appropriate, identify alternative success paths for possible inclusion in the model if warranted.

In accordance with industry practice (e.g., NUREG 1150), in general, sequences are terminated at 24 hours after the initiating event. This amount of time is considered appropriate because of the low decay heat levels that allow extended recovery times for restoring failed equipment and/or taking other corrective actions. For completeness, however, the Level 2 analysis includes consideration of "late-late" containment releases whose timing may substantially exceed the 24 hour timeframe.

Stable conditions include hot shutdown or any other condition where heat removal from the core and from the containment could continue for an extended period of time, with no requirement for additional systems to operate.

If successful core heat removal is initially established, but decay heat is being transferred to the containment without containment heat removal, core heat removal failure may ultimately occur due to excessive containment sump water environmental temperature or containment overpressurization and subsequent failure. However due to the arrangement of the plant systems the likelihood of not having containment heat removal when injection is available was shown to be negligible.

3.1.2.1 Acceptance Criteria

In the Individual Plant Examination (IPE) we are concerned with modelling two levels of consequence associated with plant accidents, "core damage" and "fission product release" following core damage. The following criteria are used in defining the plant conditions under which core damage is assumed to occur in the PRA model.

Fuel Boundary

For the onset of core damage, the acceptance criteria are those defined in 10CFR50.46 and reproduced in the IP2 updated Final Safety Analysis Report (UFSAR, page 14.3-1) as:

1) The calculated fuel rod peak clad temperature is below 2200 degrees F.

2) The amount of Zr fuel cladding that reacts chemically with water or steam does not exceed 1%.

3) Clad temperature transient is terminated when the core geometry is still amenable to cooling and localized cladding oxidation limit of 17% is not exceeded.

4) The core geometry remains coolable during and after a break in the RCS.

5) Core and decay heat is removed for an extended period of time.

In practice, (e.g., when running accident analysis codes), item (1) above or core uncovery is used as a convenient (and conservative) definition of the onset of core damage in PRAs.

In performing core degradation analysis for the containment evaluation, some sequences will be identified in which core damage occurs but total core melt is arrested prior to vessel melt through, thus limiting the release of fission products.

Reactor Coolant Boundary (with respect to overpressure)

The acceptance criterion for maintaining the integrity of the reactor coolant system boundary due to overpressure is only a real concern during an ATWS event. In WCAP-11993 (Ref. 3.1-2) 3200 psig is stated to be a conservative lower limit for the onset of leakage applicable to all Westinghouse plants, corresponding to ASME Boiler and Pressure Vessel Code level C service limit stress criterion.

The possibility of RCS integrity failure due to random component failures (e.g., LOCAs, steam generator tube rupture, stuck open PORVs, RCP seal failure) are of course considered in the model.

Containment Integrity (with respect to overpressure)

The design accident pressure of the containment is 47 psig (corresponding to about 136 °C saturation temperature). However based on calculations performed by UE&C for the IPPSS (section 4.4, page 15) the maximum pressure which the containment can tolerate before degradation (based on the lower limit of elastic response) is 126 psig.

3.1.2.2 Frontline and Support System Success Criteria

The Indian Point 2 PRA utilizes the support state modelling approach and as such the overall model is comprised of two distinct parts, namely; the support system model and the frontline model.

The basic functions required for prevention of core damage can be divided into the five functions below:

1. Reactivity Control
2. Core Heat Removal
3. Secondary Heat Removal
4. RCS Integrity
5. Containment Heat Removal

For a given initiating event, the systems that directly perform one or more of these functions are defined as frontline systems. Support systems are those that affect the course of the sequence only by means of their effect on the operation of a frontline system. The list of frontline systems is given in Table 3.1-23 together with their associated dependencies.

The dependency of support systems on other support systems is shown in Table 3.1-24. The frontline system success criteria for each initiating event were developed using the IP-2 FSAR, various generic and plant specific Westinghouse analyses (WCAPs), specific MAAP runs performed as part of this IPE study and finally through reference to other accepted PRA studies on similar PWRs (eg. Zion).

The system success criteria have been developed for six types of initiating events, LOCA's (large, medium and small), Steam Generator Tube Rupture, General Transients (which cover several different events representing similar challenges to plant systems), and Anticipated Transients without Scram (ATWS). The success criteria and corresponding reference documents or analyses are shown in Tables 3.1-1 to 3.1-6.

3.1.3 Frontline Event Trees

The objective of the event tree analysis was to modify the existing plant model developed in the IPPSS, to account for changes to the success criteria, system dependencies and plant damage state definitions identified within this IPE project (see Sections 3.1.1 and 3.1.6). In general, these changes have resulted in a more realistic plant model which is consistent with modern PRAs such as NUREG 1150.

Event trees which delineate the core damage sequences associated with the LOCAs and General Transient events with success of reactor trip are discussed in this section. The General Transient event tree differs from the other event trees in that it represents a common structure used to evaluate several transients with similar accident progressions but different mitigating system availabilities. For each frontline system event tree, the events are described to ensure that it is clear exactly what system, subsystem and operator functions are involved. The frontline system interactions are also described. Support and frontline system interactions are reflected in the split fraction dependency logic which is included for each event tree. Finally, each accident sequence has been assigned a plant damage state category which defines its specific link to the containment event tree. The accident sequence binning logic is based on the ground rules discussed in section 3.1.3.7.

3.1.3.1 Large LOCA

3.1.3.1.1 Introduction

The Large LOCA event tree (Figure 3.1-1), applies to all reactor coolant system ruptures inside the containment with blowdown rates equivalent to double-ended circumferential breaks in pipes ranging from 6 inches in diameter to the reactor coolant loop cold leg (the design basis accident). Two other large LOCAs are considered in sections 3.1.4; a large LOCA beyond the capability of the ECCS system and a LOCA that creates a direct path to outside containment.

The event tree uses the following symbols to identify system and operator functions:

IE - Initiating Event, Large LOCA
RW - Refueling Water Storage Tank
LP - Low Pressure Injection
AS - Accumulator Injection
FC - Fan Coolers
LR - Low Head Recirculation
RH - Recirculation Heat Removal
RC - Hot leg Recirculation
CS - Containment Spray Injection and Recirculation

A large LOCA is a severe event in which blowdown of the reactor coolant system occurs within a very short period of time (from seconds to a few minutes). The accumulators reflood the reactor vessel downcomer (AS), and the residual heat removal pumps restore and maintain the water level in the reactor vessel (low pressure injection LP). Due to the rapid depressurization, the nuclear reaction is shut down quickly because of voiding in the core region. Continued shutdown is ensured by the boron concentration in the injection water. Within as little as 20 to 30 minutes, the operator must switch to the cold leg recirculation mode for long term cooling (LR), and eventually (within 24 hours) switch to hot leg recirculation (RC) in order to control the boron concentration in the vessel. The containment pressure rises and pressure suppression and containment cooling is provided by the RHR heat exchangers (RH) and containment sprays or containment fan coolers (FC).

Event tree ET-1 is used to calculate the frequencies of degraded core conditions following a large LOCA. Detailed definitions of each sequential event and all systems interactions are provided.

3.1.3.1.2 Initiators

The Large LOCA event tree is initiated by random pipe breaks. Reactor vessel ruptures of a size and location within the capability of the ECCS system also initiate ET-1. These breaks are included in the calculated frequency of a large LOCA. No large pipe or vessel breaks have yet occurred in pressurized water reactors (PWRs). Large breaks may also be caused by external event influences or by sequential damage following other initiating events. External events such as seismic events and turbine missiles are excluded from this analysis.

3.1.3.1.3 Systems and Operator Functions

The top events of the Large LOCA event tree, RW through CS are described in detail to provide an understanding of the systems and operator functions involved. The numerical calculations of each top event are performed in the individual system analyses section 3.2.

3.1.3.1.3.1 RW - Refueling Water Storage Tank Supply. The RWST provides the borated water necessary for low pressure and high pressure injection. It also provides the water for the containment spray system via a separate line. The success criterion in this analysis is that the tank must contain more water than required by the technical specifications and the outlet valve to the RHR and SI pumps must be open when water is demanded. The system consists of the stainless steel tank, outlet valve and water inventory.

The RWST level is alarmed in the control room to assist in detection of deviations from the desired water level. Each of the following components have a suction line from the RWST:

- o Containment spray pumps (single suction line feeds both pumps).
- o Residual Heat Removal and Safety injection pumps (shared suction line).

(To maintain a manageable event tree structure, it is conservatively assumed that failure of event RW results in guaranteed failure of all supported systems, even though the containment spray and injection pump suction lines are not common.)

3.1.3.1.3.2 LP - Low Pressure Injection. For injection cooling to be successful, one of two RHR pumps must inject water from the RWST into at least two cold legs. Although manual actuation of the LP system is possible, only starting in response to an SI signal is credited.

3.1.3.1.3.3 AS - Accumulator Injection. Three out of four accumulators must deliver flow to the reactor coolant system. Because delivery of accumulator flow into the ruptured loop would be ineffective, three out of three accumulators must deliver flow to the three intact legs.

3.1.3.1.3.4 FC - Containment Fan Coolers. Containment fan coolers provide long term cooling for the containment atmosphere. They prevent overpressure and can effectively supply cool recirculation water to the containment sumps. The success criterion used in this analysis is three out of five fan coolers operating in the emergency mode. As the heat load is reduced after several hours, this criterion becomes quite conservative. In addition, no credit for the radionuclide removal capability of the charcoal filters associated with the fan coolers has been taken in this analysis. Because the heat sink for the fan coolers is the service water system, FC is analyzed conditional upon the success of the service water system.

In the event of failure of injection and subsequent core damage, the fan coolers may still be successful in preventing containment overpressure, providing there is an adequate steam in the containment atmosphere. MAAP calculations indicate that sufficient steam will be available from the water inventory of the RCS and successful accumulator injection.

3.1.3.1.3.5 LR - Low Pressure Recirculation. Following injection of the RWST water into the reactor coolant system and the containment, operators initiate recirculation using an eight-switch sequence. This sequence, in part, starts a recirculation pump taking suction from the recirculation sump. Alternatively, the operators can realign the suction of at least one RHR pump from RWST to the containment sump. The success of this switchover operation depends on both equipment and human action success in a specific timeframe. Time is a most important factor because difficulties in switchover from injection to recirculation can cause rapid fuel degradation. A great deal of care is given in the procedures and in the training of plant operators in this area. In the recirculation mode, with hot water flowing through the system, component cooling provides cooling to the Recirculation and RHR pumps (and RHR heat exchangers). In the absence of component cooling to the RHR heat exchangers, core decay heat can be removed by the fan coolers that are cooled by service water. Under such circumstances, the RHR pumps would be cooled by city water backup but the recirculation pumps could become inoperable. The system is modeled conditional on these bases. This event models the hardware and operator action failures associated with the recirculation function only. The actual heat removal via the RHR heat exchangers is included in event RH.

3.1.3.1.3.6 RH - Recirculation Heat Removal. This event models the heat removal via the RHR heat exchangers and is challenged following success of LR where heat removal via the fan coolers has failed. The event models the opening of the valves in the component cooling (CCW) lines to the RHR heat exchanger and its success is conditional on the success of CCW. The operator action associated with initiation of RH is included within preceding event LR.

3.1.3.1.3.7 RC - Hot Leg Recirculation. In order to flushout any boron precipitation and thereby maintain adequate boron concentration in the core, switchover from cold leg to hot leg recirculation is required in approximately 24 hours. This event models only the additional valve alignments which have to be made to achieve hot leg recirculation. Other hardware failures are modeled in the preceding event, LR, and the operator error probability is assumed to be negligible given the time available.

3.1.3.1.3.8 CS - Containment Spray. Operation of the containment sprays removes heat and fission products from the containment atmosphere.

For a Large LOCA without containment sprays, there may not be the required heat transfer to the recirculating water to permit all decay heat to be removed via the RHR heat exchangers. With coincident failure of the fan coolers, this would result in a gradual pressurization of the containment, and could ultimately challenge containment integrity. Thus in the event of failure of the fan coolers, both containment spray operation and RHR heat removal functions are conservatively assumed to be required to prevent containment failure which could then challenge the core injection systems possibly leading to core damage. This success criteria also applies to LOCA Beyond ECCS Capacity initiating event. However containment sprays are not required support core decay heat removal for medium and small LOCAs.

For fission product removal to be considered successful, the sprays must operate during periods of time when the core fission product release is occurring. Spray recirculation can be through the RHR pumps or the Recirculation Pumps and this mode may be successful following success of low head or high head recirculation (HR or LR). Since Containment Spray injection occurs prior to core damage when core injection has been successful, success of containment spray from the containment spray pumps with respect to fission product removal is only modeled when there has been no prior successful injection which would have depleted the RWST supply (ie. failure or bypass of HP, LP and LI).

3.1.3.1.4 System Interactions

The important frontline system interactions are discussed in Section 3.1.3.1.3. A support system dependency matrix is available in Tables 3.1-23 and 3.1-24. Both frontline and support system dependencies are reflected in the split fraction logic for the Large LOCA event tree, Table 3.1-7)

3.1.3.1.5 Plant Damage States

The binning logic for the Large LOCA accident sequences is shown in Table 3.1.8 and explained further in section 3.1.6

3.1.3.2 Medium LOCA Event Tree

3.1.3.2.1 Introduction

The Medium LOCA event tree (Figure 3.1-2) applies to all reactor coolant system ruptures with blowdown rates equivalent to double-ended circumferential breaks in pipes ranging from 2 to 6 inches in diameter. The event tree uses the following symbols to identify systems and plant functions:

IE - Initiating Event, Medium LOCA
RW - Refueling Water Storage Tank
HP - High Pressure Injection
AS - Accumulator Injection
L1 - Auxiliary Feedwater and Secondary Steam Relief
DZ - Post LOCA Cooldown and Depressurization
Y1 - Core Cooling Recovery
LP - Low Pressure Injection
FC - Fan Coolers
HR - High Head Recirculation
DP - Depressurize before Vessel Failure
LI - Late Injection
LR - Low Head Recirculation
RH - Recirculation Cooling
CS - Containment Spray

A Medium LOCA is much less severe than a large LOCA. To avoid extensive core damage following a medium LOCA, emergency coolant injection must be provided by at least one high head injection pump and three accumulators. Secondary side heat removal is not a requirement since the break size is large enough to remove all the decay heat. As an alternative, in the event of high head injection pump failing, core cooling may be recovered utilizing rapid secondary/primary depressurization with auxiliary feedwater and atmospheric steam dumps followed by successful ECCS injection and heat removal using the accumulators and one of two RHR pumps. The criterion is conservative for specific break sizes but is adequate to cover the entire range of Medium LOCAs.

Recirculation from the appropriate containment sump must also be successful requiring low head or high head recirculation (LR or HR) depending upon the RCS pressure when the RWST is exhausted.

Containment cooling is necessary to prevent long term overpressure, and may be achieved utilizing fan coolers (FC) or RHR heat exchangers (RH).

Event tree ET-2 is used to calculate the frequencies of degraded core states following a Medium LOCA.

3.1.3.2.2 Initiators

The Medium LOCA event tree (ET-2) is initiated by random pipe breaks in the RCS and connecting piping. Certain adverse break locations in the high pressure injection lines could require the success of two high head injection pumps rather than as mentioned above. The likelihood of such a specific break has been specifically analyzed and determined not to contribute significantly to risk and is not considered within this event tree. Medium breaks may also be caused by external event influences which are also excluded from this analysis.

3.1.3.2.3 Systems and Operator Functions

The top events of the Medium LOCA event tree (ET-2), events RW through CS are described in detail to provide an understanding of the system and operator interactions as they specifically relate to this event. The numerical calculations of each top event are performed in the individual systems analyses described in Section 3.2.

3.1.3.2.3.1 RW - The Refueling Water Storage Tank Supply. See discussion under Large LOCA in Section 3.1.3.1.3.1.

3.1.3.2.3.2 HP - High Pressure Safety Injection. For the smaller medium LOCAs (< 4in), the RCS will not be depressurized by the break and success requires that one of the three safety injection pumps deliver flow from the RWST to the RCS in response to a safety injection signal.

3.1.3.2.3.3 AS - Accumulator Injection. See discussion under Large LOCA in Section 3.1.3.1.3.2

3.1.3.2.3.4 L1 - AFWS Actuation Although secondary side cooling is not a requirement for successful Medium LOCA mitigation, it facilitates the core cooling recovery function (event Y1) in the event of failure of high pressure injection (HP), or a post LOCA cooldown and depressurization (event DZ) following success of event HP. The success of the auxiliary feedwater system depends on the start of motor driven pumps or the turbine-driven pump in response to an automatic actuation signal or operator action. The automatic signals that start the auxiliary feedwater pumps for this event tree come from safety injection or low-low steam generator level. The AFS success criteria following failure of high pressure injection is two motor driven or one turbine driven pump feeding four steam generators. This has been confirmed by specific MAAP analyses. In other cases one motor driven or the turbine driven pump feeding one steam generator is adequate.

3.1.3.2.3.5 DZ - Post LOCA Cooldown and Depressurization Following successful high pressure injection (HP), the operators are instructed to begin cooldown of the RCS at a rate which is less than 100 °F per hour. Successful completion of this operation prior to emptying the RWST will enable low head recirculation (LR) to be used instead of high head recirculation (HR). Success of event DZ requires one of the four SG atmospheric relief valves to open.

3.1.3.2.3.6 Y1 - Core Cooling Recovery. For breaks less than 4 inches core cooling recovery is required following failure of high pressure injection system. This requires the operator to initiate steam dump from the steam generators in sufficient time to complete depressurization prior to core damage. This analysis conservatively assumes that the operators do not begin such action until there is indication of inadequate core cooling as directed by the EOPs - that is, when the core exit thermocouples readings exceed 1200 °F. This may be achieved using the condenser steam dumps or atmospheric steam relief valves. This analysis only models the latter and assumes that 3 of 4 valves are required to open. This success criteria has been verified by specific MAAP analyses, as having the time available to take operator action. Operator action is also included within this event (Y1).

3.1.3.2.3.7 LP - Low Pressure Injection. Following failure of high pressure injection and RCS depressurization, delivery of low pressure injection flow from the RWST via one of two RHR pumps is required. Although manual starting of low pressure injection is possible, only starting in response to an SI signal has been modeled.

3.1.3.2.3.8 FC - Fan Cooler Units. See discussion under Large LOCA in Section 3.1.3.1.3.4.

3.1.3.2.3.9 HR - High Head Recirculation This event models switchover from high head injection to high head recirculation following exhaustion of the RWST supply. Cooling of the recirculated water may be by fan coolers (event FC) or RHR heat exchangers (event RH).

3.1.3.2.3.10 DP - Depressurization before Vessel Failure. In the event of inadequate core cooling, the EOPs require the operators to blow down unfaulted steam generators to atmospheric pressure at the maximum rate. Success of this event will reduce the RCS to a lower pressure regime and permit low pressure injection following core damage but prior to vessel failure. Secondary depressurization can only be accomplished if auxiliary feedwater is available and atmospheric relief valves have not failed in the preceding events DZ or Y1. (Note: Although this event is included in the event tree, we have consevatively taken no credit for its success in the current binning of accident sequences.)

3.1.3.2.3.11 LI - Low Head Injection - Late. Prior to core damage, the low head pumps may be operational but not capable of injecting due to high RCS pressure. However, the status of low head injection at the time of core damage and vessel failure is important to the Plant Damage State grouping for the Level 2 analysis. This event, therefore, represents the operation of at least one of the two low head injection (RHR) pumps injecting water from the RWST into the RCS following core damage or vessel failure.

This event is not challenged when high head injection is successful and there is therefore sufficient inventory in the containment sump to establish low head recirculation. Neither is the event challenged when the RWST, low pressure injection or high head recirculation has previously failed due to complete or partial dependencies.

3.1.3.2.3.12 LR - Low Pressure Recirculation. This event models the normal switchover from injection to recirculation from the containment or recirculation sump when the RWST is exhausted following success of DZ, as described in Section 3.1.3.1.3.5. LR also models failure to provide continuous make up to the vessel following core damage and vessel depressurization as a result of induced hotleg failure.

This event is not challenged following failure of RWST, LP, HR, or LI due to dependencies.

3.1.3.2.3.13 RH - Recirculation Cooling. See discussion under Large LOCA in Section 3.1.3.1.3.6

3.1.3.2.3.14 CS - Containment Spray. See discussion under Large LOCA in Section 3.1.3.1.3.7.

3.1.3.2.4 System Interactions

The important frontline system interactions are discussed in Section 3.1.3.2.3. A support system dependency matrix is available in Tables 3.1-23 and 3.1-24. Both frontline and support system dependencies are reflected in the split fraction logic for the Medium LOCA event tree shown in Table 3.1-9.

3.1.3.2.5 Plant Damage States

The binning logic for the Medium LOCA accident sequences is shown in Table 3.1-10 and explained further in Section 3.1.6.

3.1.3.3 Small LOCA Event Tree

3.1.3.3.1 Introduction

The Small LOCA event tree (Figure 3.1-3) applies to all reactor coolant system ruptures with blowdown rates equivalent to double-ended circumferential breaks in pipes less than 2 inches in diameter. The event tree uses the following symbols to identify systems and operator functions:

IE - Initiating Event, Small LOCA
RW - Refueling Water Storage Tank
HP - High Pressure Injection
L1 - AFWS Actuation and Secondary Cooling
O1 - Primary Cooling Bleed
DZ - Post LOCA Cooldown and Depressurization
Y1 - Core Cooling Recovery
AS - Accumulator Injection
LP - Low Pressure Injection
FC - Fan Coolers
HR - High Head Recirculation
DP - Depressurize Before Vessel Failure
LI - Late Injection
LR - Low Head Recirculation
RH - Recirculation Cooling
CS - Containment Spray

A Small LOCA should be a relatively mild event. Event tree ET-3 is used to calculate the frequencies of degraded core conditions following Small LOCA. To avoid core damage, emergency coolant injection must be provided by one high pressure safety injection pump. Since the reactor coolant system is not depressurized, a reactor trip is required to shut down the nuclear chain reaction. Also, because blowdown may be insufficient to provide core cooling, either AFWS operation with secondary cooling or primary bleed and feed cooling is required. Alternatively, secondary/primary depressurization using atmospheric steam dumps will permit successful ECCS injection and heat removal using one of two RHR pumps and 3 of 4 accumulators injecting into the intact cold legs. For long term cooling, several alternatives are possible: high pressure recirculation, depressurization and low pressure recirculation, or depressurization and RHR cooling (with leak isolation or make up if needed). Only the first two are modeled. Containment cooling utilizing fan coolers or RHR heat exchangers prevents long term pressure buildup.

3.1.3.3.2 Initiators

The Small LOCA event tree (ET-3) is initiated by random pipe breaks and valve failures. Small breaks may also be initiated by external event influences or by consequential damage following other initiating events (eg. RCP seal LOCA or stuck open PORV). Consequential small LOCA events are modeled within the event tree corresponding to the original initiating event (ie. Loss of Offsite Power and General Transient trees). External events are excluded from this analysis.

3.1.3.3.3 Systems and Operator Functions

The top events of the Small LOCA event tree (ET-3), RW through CS, are described in detail to provide an understanding of the systems and operator functions involved. The numerical calculations of each top event are performed in the individual systems analyses described in Section 3.2.

3.1.3.3.3.1 RW - The Refueling Water Storage Tank Supply. See discussion under Large LOCA in Section 3.1.3.1.3.1

3.1.3.3.3.2 HP - High Pressure Safety Injection. For the Small LOCA events the RCS will not be depressurized by the break and success requires that one of the three safety injection pumps deliver flow from the RWST to the RCS in response to a safety injection signal.

3.1.3.3.3.3 L1 - AFWS Actuation and Secondary Steam Relief. Secondary side cooling is a requirement for successful Small LOCA mitigation since the break size is not adequate to remove all the decay heat. It also facilitates the core cooling recovery function (event Y1) in the event of failure of high pressure injection (HP), or a controlled cooldown and depressurization (event DZ) following success of event HP. The success of the auxiliary feedwater system depends on the start of motor driven pumps or the turbine-driven pump in response to an automatic actuation signal or operator action. The automatic signals that start the auxiliary feedwater pumps for this event tree come from safety injection or low-low steam generator level.

The AFS success criteria following failure of high pressure injection is two motor driven or one turbine driven pump feeding four steam generators. This has been confirmed by specific MAAP analyses. In other cases one motor driven or the turbine driven pump feeding one steam generator is adequate.

Secondary steam relief is achieved by removing heat from the steam generators. This is done by automatically or manually opening an atmospheric relief valve(s) associated with a steam generator(s) receiving auxiliary feedwater. Heat is also adequately removed by safety relief valves which are self actuating, or condenser steam dumps.

Due to the high level of redundancy and lack of any necessity for support systems, secondary steam relief valves are not explicitly modeled unless cooldown is required (...see event DZ and Y1). Heat removal from the primary system can be provided by one steam generator. Given these conditions, the reactor core will be cooled by forced flow or by single or two-phase natural circulation to the steam generator.

3.1.3.3.3.4 O1 - Primary Cooling Bleed. If auxiliary feedwater cooling should fail but high pressure injection is successful, the operator can manually open the power-operated relief valve (PORV) block valves (if they are closed) and PORVs to provide bleed and feed cooling to the primary system.

3.1.3.3.3.5 DZ - Post LOCA Cooldown and Depressurization. See discussion for Medium LOCA under Section 3.1.3.2.3.5.

3.1.3.3.3.6 Y1 - Core Cooling Recovery. See discussion for Medium LOCA events in Section 3.1.3.2.3.6.

3.1.3.3.3.7 AS - Accumulator Injection. See discussion under Large LOCA in Section 3.1.3.1.3.2

3.1.3.3.3.8 LP - Low Pressure Injection. See discussion under Medium LOCA in Section 3.1.3.2.3.7.

3.1.3.3.3.9 FC - Fan Cooler Units. See discussion under Large LOCA in Section 3.1.3.1.3.4

3.1.3.3.3.10 HR - High Head Recirculation See discussion under Medium LOCA in Section 3.1.3.2.3.9.

3.1.3.3.3.11 DP - Depressurization before Vessel Failure. See discussion under Medium LOCA in Section 3.1.2.3.10.

3.1.3.3.3.12 LI - Low Head Injection - Late. See discussion under Medium LOCA in Section 3.1.3.2.3.11.

3.1.3.3.3.13 LR - Low Pressure Recirculation. See discussion under Medium LOCA in Section 3.1.3.2.3.12.

3.1.3.3.3.14 RH - Recirculation Cooling. See discussion under Large LOCA in Section 3.1.3.1.6

3.1.3.3.3.15 CS - Containment Spray. See discussion under Large LOCA in Section 3.1.3.1.3.8

3.1.3.3.4 System Interactions

The important frontline system interactions are discussed in Section 3.1.3.3.3. A support system dependency matrix is available in Tables 3.1-23 and 3.1-24. Both frontline and support system dependencies are reflected in the split fraction logic for the Small LOCA event tree shown in Table 3.1-11.

3.1.3.3.5 Plant Damage States

The binning logic for the Small LOCA accident sequences is shown in Table 3.1-12 and explained further in Section 3.1-6.

3.1.3.4 General Transient with Successful Scram

3.1.3.4.1 Introduction

The fundamental requirements for mitigation of all transients (non LOCA or SGTR) are identical. In some cases however, there are differences in the availability of each mitigating function, depending upon the specific initiating event, which results in the necessity for performing separate quantifications.

The same general transient event tree structure, shown in Figure 3.1-4, is used for quantifying all of the following initiating events.

Loss of Main Feedwater with No Recovery
Closure of a Main Steam Isolation Valve
Core Power Excursion
Turbine Trip due to
- Loss of all service water
- Other (independent) Causes

Reactor Trip due to
- Loss of dc bus 21
- Loss of dc bus 22
- Loss of component cooling water
- Other (independent) causes

Steam Line Break Inside Containment
Steam Line Break Outside Containment

Turbine trip due to loss of offsite power event is evaluated separately in Section 3.1.4, due to the necessity to consider time phased recovery actions to avoid gross conservatism.

In all cases RCS cooling can be provided by AFS and secondary side steam relief, or directly by primary bleed and feed cooling. In addition consequential small LOCA event due to a stuck open pressurizer PORV, loss of RCP cooling or steam generator tube rupture (an issue for steam line break inside containment events) must be prevented or mitigated. Only in the case of a primary bleed cooling or the occurrence of a consequential LOCA, is containment heat removal required using fan coolers or RHR heat exchangers.

When the main turbine trips during power operation, the main feedwater pump turbine drives subsequently trip. Several signals including SI, also trip the main feedwater pumps or feedwater valves. Recovery of main feedwater is a slow manual process and some operator action dependencies with AFS (manual initiation of flow from turbine driven pump) and initiation of feed and bleed do exist. Therefore, recovery of main feedwater has not been included as part of this PRA model. Similarly, condenser steam dump is not included as a source of secondary side heat removal. These simplifying, albeit somewhat conservative, assumptions serve to increase the similarity of accident mitigation modeling among the various types of transients.

Uncontrolled blow down of steam generators

Uncontrolled blow down of any or all steam generators is a concern in the modeling of transients for three reasons:

1. the impact on auxiliary feedwater availability

2. the resulting potential for pressurized thermal shock (PTS) and vessel failure due to rapid RCS cooldown (> 100 deg F/hr) concurrent with, or followed by represurization due to continued charging flow and/or initiation of high pressure injection.

3. the potential for steam generator tube rupture and containment bypass caused by excessive blow down rates beyond those achievable via normal blow down paths. This is only a significant issue following steam line breaks inside containment since flow limiting venturis up stream of the MSIVs prevent excessive blow down rates in all other cases.

In the event of a general transient (non LOCA, or SGTR) uncontrolled blow down may occur due to:

a) a stuck open safety or atmospheric relief valve.

b) failure of any MSIV to close in combination with a failure of any turbine trip or steam dump valve to close.

c) steam line break inside or outside containment

In such cases operators enter the faulted steam generator EOP (E-2) where they are instructed to isolate feedwater to the affected steam generator. Thus the cooling capability of one of the steam generators is lost, and possibly, one of the two steam supplies to the turbine driven pump (if the faulted SG is 22 or 23). The RCS can be adequately cooled by one steam generator. The motor and turbine driven AFW pumps deliver flow to two and four SGs respectively. Thus the impact of one faulted steam generator on AFS availability is negligible. In the unlikely event of two or three steam generators being faulted coincidentally, due to some common cause failure of turbine trip and/or common cause failure of the MSIVs to close, the AFW turbine driven pump steam supplies may be failed but flow from at least one motor driven pump would be available to at least one steam generator. The probability of 2 or 3 faulted SGs in combination with failure of flow from one of 2 motor driven pumps is a negligible contributor to the unavailability of AFW. Finally, in the event of a failure which results in the blow down of all four steam generators, EOP ECA 2.1 will be entered which recognizes that some secondary side cooling is required while at the same time minimizing the potential for PTS. This procedure directs operators to maintain level in each steam generator up to 5% (narrow range) unless RCS cooldown exceeds 100 °F per hour. If cooldown is excessive then feed water flow to each SG is manually controlled at 25 gpm. Thus, although turbine driven pump flow may be failed (due to loss of both steam supplies), adequate cooling can still be maintained by either of the two motor driven pumps. Again this worst case blow down condition does not contribute significantly to the AFW unavailability.

Based on SECY-82-465 (Ref. 3.1-3), the NRC had concluded that the risk from PTS events is acceptable for reactor vessels with RD_{NDTO} (Reference Temperature for Return to Nil Ductility Transition) values less than than 270 deg F for axial welds, and 300 deg F for circumferential welds. This is based on an evaluation of the frequency and severity of overcooling transients and the corresponding conditional probabilty of vessel failure due to PTS. The limiting RD_{NDTO} value for the IP-2 vessel welds is estimated to be 220 deg. F at 22 EFPY, which approximately corresponds to a 40 year plant operating life (Ref. 3.1-4). Thus, uncontrolled blowdown events need not be considered further with respect to PTS.

The potential for consequential steam generator tube rupture following steam line break inside containment (upstream of the flow limiters) exists due to the rapid increase in tube pressure differential. Mitigation of this event is modeled as a small break LOCA. The break is inside containment and the likelihood of a leak outside containment is insignificant since there will be no challenge to the secondary relief valves which could result in a stuck open valve.

The general transient event tree (see Figure 3.1-4) uses the following symbols to identify systems and operator functions:

IE - Initiating Event, General Transient
PV - Pressurizer PORV fails to reclose
LS - Loss of all RCP seal Cooling
TR - Consequential Steam Generator Tube Rupture
L1 - AFWS Actuation and Secondary Cooling
RW - Refueling Water Storage Tank
HP - High Pressure Injection
O1 - Primary Cooling Feed and Bleed
FC - Fan Coolers
HR - High Head Recirculation
DP - Depressurize before Vessel Failure
LI - Late Injection
LR - Low Head Recirculation
RH - Recirculation Cooling
CS - Containment Spray

3.1.3.4.2 Initiators

Specific details associated with each of the general initiators considered in this section are discussed below:

3.1.3.4.2.1 Loss of main feedwater (LOFW). This initiator applies to those transients that begin with the loss of both main feedwater pumps due to a variety of reasons including human error, control logic failures, mechanical failures of main feedwater pumps, and loss of condensate and related problems. The normal progress of these transients is reactor trip, turbine trip resulting from reactor trip, and auxiliary feedwater actuation resulting from low-low steam generator level. This is followed by the operator taking control of the AFWS and secondary cooling.

3.1.3.4.2.2 Closure of One Main Steam Isolation Valve (MSIVC). This initiator applies to those transients that begin with a closure of one of the four MSIVs and are followed by an automatic reactor trip or turbine trip. Trips of two or three MSIVs would follow the same event tree, but are much less likely. The normal progress of this transient is a reactor trip resulting from a low-low steam generator level. This is caused by shrinkage in the steam generator from MSIV closure. Also, turbine trip is actuated directly from the MSIV closure and from the reactor trip breakers. If an MSIV trip occurs without turbine trip or reactor trip, it is possible at some power levels that the operator will stabilize the plant on three loops and then performs a controlled shutdown. No credit is given for this form of mitigation in the model. Normally this would be a benign transient of fairly infrequent occurrence. The closure of one MSIV would result from an operating error or equipment malfunction because an automatic signal does not close just one MSIV.

3.1.3.4.2.3 Loss of Reactor Coolant System Flow (LOPF). This initiator applies to those transients that begin with the loss of RCS flow because of control logic failure, human error or mechanical failure of the RCS pump(s). The normal progress of these transients is reactor trip resulting from low reactor coolant flow, RCP bus undervoltage, underfrequency, or RCP breaker trip; turbine trip resulting from reactor trip, and auxiliary feedwater actuation because of low-low steam generator level. This is followed by the operator taking control of the AFWS and secondary cooling.

3.1.3.4.2.4 Core Power Excursion (CPI). This initiator applies to those transients that begin with a core power excursion caused by random events. This accident progresses relatively slowly. An operator should respond to increasing Tavg by searching for the cause of the transient. Until the cause is determined, the effects can be opposed by negative reactivity insertion. Once identified, the cause can be terminated. If the core power excursion is not terminated, turbine runback occurs from an automatic signal generated from the overpower delta T circuitry. Success of turbine runback in preventing reactor trip depends upon the operator stabilizing power below a reactor trip setpoint. For simplicity in the PRA model no credit is given for terminating the accident prior to reactor trip and core power excursion is therefore conservatively modeled as if it were a reactor trip.

3.1.3.4.2.5 Turbine Trip (TTRIP). Two different causes of turbine trip are considered separately within this model (excluding loss of offsite power which is discussed in section 3.1.4). The first includes all turbine trips which may occur due to a variety of mechanical or electrical failures but do not degrade accident mitigating systems. The second is turbine trip resulting from the loss of all service water due to loss of cooling to the turbine auxiliaries.

Turbine trips of the first type are relatively mild transients that plants may experience each year. In general, no problems should occur following a turbine trip. The reactor should trip immediately as a result of the turbine trip signal, and the auxiliary feedwater should start when the levels in the steam generators fall. As long as auxiliary feedwater is being supplied to the steam generators, the multitude of pathways for the steam to escape from the steam generators ensures secondary cooling. Cooling of the core will follow by natural circulation or forced circulation. The auxiliary feedwater system is designed to operate without service water and can succeed without offsite electric power. Therefore, successful termination of the turbine trip transient requires only a reactor trip, normal actuation of auxiliary feedwater, successful closing of PORVs (if opened) and cooling of the RCP seals.

The second type of turbine trip is potentially much more severe since loss of all service water results in the loss the heat sink to the component cooling system which is the primary means of cooling the RCP thermal barriers and charging pumps, ECCS pumps and RHR heat exchangers. Service water also provides cooling water to the containment fan coolers. When component cooling is lost, an AOI (A-4.1.1) directs operators to establish alternate cooling for the charging and ECCS pumps from the city water supply, thus maintaining RCP seal injection and thereby preventing a seal LOCA. If this is unsuccessful, a seal LOCA is assumed to occur which can be mitigated in the short term by high head injection but will result in core damage in the long term due to lack any means of removing heat from the core during recirculation. This is an extremely conservative model, due to lack of any credit for recovery actions, and was used since even with such conservatism, this is not a dominant risk contributor.

3.1.3.4.2.6 Reactor Trip (RXTRIP). Four different causes of reactor trip are considered separately. The first includes those transients that begin with an automatic or manual reactor trip other than those which leave mitigating systems degraded (as explicitly discussed in the following three cases). The second is a sequence initiated by a loss of component cooling. An automatic trip would occur if the operators tripped the reactor coolant pumps. A manual trip or very rapid shutdown is also possible. The third is a sequence initiated by loss of a DC bus 21 or 22. The fourth is a sequence initiated by loss of 6.9kv Bus 2 or 3 which results in loss of one of the four reactor coolant pumps.

The normal progress of these transients is a turbine trip resulting from the reactor trip, and auxiliary feedwater actuation because of low-low steam generator level. This is typically a benign transient which occurs quite frequently relative to other transients. However, it does place demands on standby cooling systems that must function properly to maintain plant integrity. If auxiliary feedwater fails, primary bleed and feed cooling, and recirculation cooling, must be established by operator action.

In the case of a loss of a component cooling water initiated event, RCP seal integrity must be maintained by charging pumps, cooled by city water pumps. If a consequential small LOCA occurs, or if feed and bleed cooling is required, then ECCS pumps must also be cooled by city water or primary makeup water in the long term, and containment heat removal must be provided by the fan cooler units.

In the case of an event initiated by loss of a DC bus, operation of several functions is degraded, including loss of sufficient bleed cooling. Loss of a 6.9 kv bus 2 or 3 results in loss of offsite power to bus 2A or 3A, respectively.

3.1.3.4.2.7 Steam Break Inside Containment. This initiator applies to those transients that begin with a steam line break inside containment. The normal progress of this transient is the start of HPIS, AFS and reactor trip resulting from the safety injection signal which will be generated by one of the following signals:

a. Low pressurizer pressure.
b. Steam generator, delta P (one steam generator 150 psi less than the other three).
c. High containment pressure.

Main steam isolation valve (MSIV) closure will also occur due to low steam line pressure and high steam line flow, or hi-hi containment pressure. The operator controls secondary side cooling, which is adequate to maintain stable conditions in the absence of a consequential LOCA. A consequential LOCA may occur due to an SGTR, as well as a stuck open primary relief valve or loss RCP cooling.

The potential risk from pressurized thermal shock (PTS) or steam generator tube rupture following steam line break is discussed in Section 3.1.3.4.1 and concluded to be insignificant. Such events are therefore not modeled explicitly in the event tree.

Containment cooling is required to avoid excessive pressure if feedwater flow is not terminated to the faulted steam generator. However, such an event is extremely unlikely and overpressure by itself would not necessarily threaten the core. Containment cooling using fan coolers or RHR heat exchangers is therefore only challenged when feed and bleed is used or in the event of a consequential small LOCA.

3.1.3.4.2.8 Steam Break Outside Containment. This initiator applies to those transients that begin with a steam line break outside containment. The normal progress of this transient is high head safety injection, reactor trip and auxiliary feedwater system actuation resulting from the safety injection signal. SI is generated by one of the following signals.

a. Low pressurizer pressure.
b. High steam flow with low Tavg or low steam pressure.

The MSIVs also close on a high steam flow safety injection signal. The operator controls secondary side cooling, which is adequate to maintain stable conditions in the absence of a consequential small LOCA. Containment cooling using fan coolers or RHR heat exchangers is therefore only challenged when feed and bleed is used or in the event of a consequential small LOCA.

3.1.3.4.3 Systems and Operator Functions

The top events of the General Transient event tree, PV thru CS, are described in detail to provide an understanding of the systems and operator functions involved. The calculated values for each top event are provided in the individual systems analyses in Section 3.2.

3.1.3.4.3.1 PV - PORVS Reclose Following the initial transient the PORVs may be challenged (WCAP 9804 Ref. 3.1.-5) in which case at least one valve may fail to reclose. This would represent a consequential small LOCA if the associated block valve was not closed by the operator. This event is therefore logically constructed as follows:

PV = (PORV Challenge Rate) x (PORV fails to reclose) x
(Operator, hardware or electrical fault prevents
block valve from closing)

The challenge rate is initiator specific.

3.1.3.4.3.2 LS RCP Seal Cooling. This event represents the availability of cooling and injection to the RCP seals from either the Charging Pumps or the Component Cooling System (CCS). Following loss of service water or CCS, RCP seal injection from the Charging Pumps and Component cooling to the RCP thermal barriers are initially lost. High temperature reactor coolant begins to flow out from the loops and flash within the seals resulting in the potential for seal failure which is assumed to occur. In such cases RCP seal LOCA may be prevented by the operator restarting a charging pump and establishing seal injection according to the EOP instructions. Since the charging pumps drives are normally cooled by CCW, which is not available, the operator must initially set the charging pump flow controller to maximum, which extends the time the pump can operate without cooling (ref 3.1-6), and establish an alternate cooling water supply via the City Water/CCS cross connect. With the pumps at minimum speed the operating time prior to damage would only be a few minutes.

The logic for this event therefore is represented by:

LS = (failure of CCS) x (failure of charging system + operator error)

3.1.3.4.3.3 TR - Consequential Steam Generator Tube Rupture. As discussed in Section 7.1, this event is only challenged following a steam line break inside containment initiating event. The conditional probability of this event (2.70 E-02 per yr.) is obtained from an analysis discussed in NUREG 0844 (Ref. 3.1-7). Failure of this event implies the requirement for small LOCA accident mitigation.

3.1.3.4.3.4 L1 - AFWS Actuation and Secondary Cooling. The success of the auxiliary feedwater system depends on the start of one motor driven pump or the turbine-driven pump in response to an automatic actuation signal or operator action. The automatic signals that start the auxiliary feedwater pumps for this event tree come from safety injection or low-low steam generator level. Secondary steam relief is achieved by removing heat from the steam generators. This is done by automatically or manually opening an atmospheric relief valve(s) associated with a steam generator(s) receiving auxiliary feedwater. Heat is also adequately removed by safety relief valves which are self actuating, or condenser steam dumps. Due to the high level of redundancy and lack of any necessity for support systems, secondary steam relief valves are not explicitly.

Heat removal from the primary system can be provided by one steam generator. Given these conditions, the reactor core will be cooled by forced flow or by single or two-phase natural circulation to the steam generator.

3.1.3.4.3.5 RW - The Refueling Water Storage Tank Supply. See discussion under Large LOCA in Section 3.1.3.1.3.1

3.1.3.4.3.6 HP - High Pressure Safety Injection. Following a consequential small LOCA or failure of AFW, success requires that one of the three safety injection pumps deliver flow from the RWST to the RCS. Manual initiation of High Pressure Injection is also required for bleed and feed operation in the event of a failure of AFS.

3.1.3.4.3.7 O1 - Primary Cooling Bleed. If auxiliary feedwater cooling should fail but high pressure injection is successful, the operator can manually open the pressurizer power-operated relief valve (PORV) block valves (if closed) and PORVs to provide feed and bleed cooling to the primary system.

3.1.3.4.3.8 FC - Fan Cooler Units. See discussion under Large LOCA in Section 3.1.3.1.3.4.

3.1.3.4.3.9 HR - High Head Recirculation. See discussion under Medium LOCA in Section 3.1.3.2.3.9.

3.1.3.4.3.10 DP - Depressurization before Vessel Failure. See discussion under Medium LOCA in Section 3.1.3.2.3.10.

3.1.3.4.3.11 LI - Low Head Injection - Late. See discussion under Medium LOCA in Section 3.1.3.2.3.11.

3.1.3.4.3.12 LR - Low Pressure Recirculation. See discussion under Medium LOCA in Section 3.1.3.2.3.12.

3.1.3.4.3.13 RH - Recirculation Cooling. See discussion under Large LOCA in Section 3.1.3.1.3.6.

3.1.3.4.3.14 CS - Containment Spray. See discussion under Large LOCA in Section 3.1.3.1.3.8.

3.1.3.4.4 System Interactions

The important frontline system interactions are discussed in Section 3.1.3.4.3. A support system dependency matrix is available in Tables 3.1-23 and 3.1-24. Both frontline and support system dependencies are reflected in the split fraction logic for the General Transient event tree shown in Table 3.1-13.

3.1.3.4.5 Plant Damage States

The binning logic for the General Transient accident sequences is shown in Table 3.1-14 and explained further in Section 3.1.6.

3.1.4 Special Event Trees

The event trees described in this section delineate accident progression following Loss of Offsite Power, Steam Generator Tube Rupture, Interfacing Systems LOCA and LOCA beyond ECCS Capacity initiating events. The objectives of this analysis and the contents of this section are similar to that described in Section 3.1.3.

3.1.4.1 Steam Generator Tube Rupture

3.1.4.1.1 Introduction

The Steam Generator Tube Rupture event tree (Figure 3.1-5) applies to the rupture of one or more steam generator tubes causing primary coolant to leak to the secondary system. The event tree uses the following symbols to identify system and operator functions:

IE - Initiating Event Steam Generator Tube Rupture
RW - Refueling Water Storage Tank Supply
HP - High Pressure Injection
O3 - Operator Cooldown and Depressurize RCS - early (without AFS)
L1 - AFWS Actuation and Secondary Cooling
OS - Isolate Ruptured Steam Generator-Early
O4 - Operator Cooldown and Depressurize RCS - early (with AFS)
O5 - Operator Cooldown, depressurize - Late
SO - Isolation of Ruptured Steam Generator - Late
MU - RWST Makeup
AS - Accumulators
LP - Low Pressure Injection
LR - Low Head Recirculation
RH - Recirculation Heat Removal

Steam Generator Tube Rupture is unique for several reasons. First, it is a small LOCA, in some ways more severe and in other ways less severe than the event modeled in Section 3.1.3.3. It is an interfacing systems LOCA, releasing reactor coolant into the secondary system which provides several paths outside containment-- the normal path via the main steam line to the condenser to the condenser exhaust, via the main steam line to the steam generator atmosheric relief valves or safety valves or via the steam generator blowdown line.

Since the secondary side is at high pressure the loss of coolant can be controlled. If the secondary side of the ruptured steam generator is isolated and the reactor coolant pressure reduced to below the steam generator safety valve set point the leak is stopped. However these are both manual actions (except automatic isolation of the SG blowdown lines on high radiation); the operators must respond or the leak will continue and, unlike the "normal" small LOCA the lost water will be outside containment, unavailable for recirculation.

On the positive side, the leak is small, limited by both size of the tube rupture and the leakage mode from the generator. Thus the time limit for the operator to take action is relatively long; he has at least 20 minutes based on plant specific analyses, to begin taking actions to control the break flow to avoid passing liquid through an atmospheric relief or safety valve (such that the potential for a stuck open valve increases significantly). Furthermore, even if the break flow is not terminated many hours are available to cooldown and depressurize the RCS to atmospheric pressure before the make up from the RWST via the SI pumps is exhausted. Additional makeup can also be provided to the RWST from the primary water storge tank.

The following analysis applies to double ended ruptures of a single tube. Sensitivity studies performed as part of the IPPSS, (page 1.3-172) indicate that the models would apply to multiple breaks but some events would occur more quickly. Hence, the operator would need to act more quickly and his chances of failure would increase. This is offset by the reduced frequency of multiple breaks. (All SGTR events to date have involved leakage through a single tube.) The IPPSS concludes that the single tube rupture model bounds multiple rupture cases.

Following a steam generator tube rupture, automatic reactor trip and safety injection will occur due to low pressurizer pressure, or over temperature delta T. Normal feed flow isolates and the AFS will actuate automatically (flow from motor driven pumps only). With the current IP2 operating mode the condenser steam dumps are not expected to automatically open and initial secondary cooling will probably be via the atmospheric relief valves. When the post trip RCS cooldown subsides, safety injection will begin refilling the pressurizer and increase RCS pressure until injection flow equals the break flow, thus maintaining the primary coolant system inventory constant. The equilibrium pressure is dependent upon the size of the tube rupture and the injection capacity.

Once the SGTR scenario is identified (due to high radiation levels or uncontrolled rising SG level), the SGTR Emergency Operating Procedure (E-3) is entered and the ruptured generator isolated (MSIV AFS feed and blowdown) to minimize activity release and facilitate termination of the break flow. The RCS will then be cooled down utilizing the steam dumps or atmospheric relief valves to achieve the desired core exit temperature (ie. 50 deg F below the saturation temperature at the ruptured SG pressure -- 510 deg F at 1000psig).

After the primary temperature is reduced, the RCS is depressurized to the ruptured SG pressure to terminate the break flow. The preferred method of depressurization is the normal pressurizer spray system. When this is not available or not effective, the primary pressure is achieved by opening a PORV.

When the RCS pressure is equal to the ruptured SG pressure, the PORV (or spray valve) is closed. Depressurization may be terminated on high pressurizer level to prevent filling of the pressurizer. Pressurizer level, and consequently RCS pressure, continue to rise until safety injection is terminated when there is assurance that the RCS pressure is stable (or increasing) and RCS adequate subcooling has been achieved. Under these circumstances, the LOCA has been terminated and stable conditions are restored with heat being removed via natural circulation and steaming through the good generators.

In the event that the ruptured steam generator is not isolated or the RCS is not depressurized within a relatively short time after the initiating event (actual time depends on the size of the break), the steam generator may overfill resulting in the discharge of two phase flow through the atmospheric relief valve or the safety relief valve. This leads to an increased chance of a valve sticking open (a stuck open SRV is more serious than an ARV since there is no associated block valve) which would prevent the LOCA termination and require cooldown of the RCS to atmospheric conditions, using RHR, in order to achieve stable conditions. Furthermore, a stuck open valve would present a potential containment bypass pathway in the event that core damage were to occur. Failure to isolate the ruptured steam generator before overfill is considered in the event tree model.

3.1.4.1.2 Initiators

The Steam Generator Tube Tupture event tree (ET-4) is initiated by a single, random tube rupture. While the events are modeled for a single double ended break, sensitivity calculations indicate that in most respects, breaks of one to three tubes behave in much the same way as discussed above.

3.1.4.1.3 Systems and Operator Functions

The top events of the steam generator event tree (ET-4), RW through CS, are described in detail to provide an understanding of the systems amd operator functions involved. The numerical calculations of each top event are performed in the individual system analyses described in Section 3.2.

3.1.4.1.3.1 RW - The Refueling Water Storage Tank Supply. See discussion under Large LOCA in Section 3.1.3.1.1.

3.1.4.1.3.2 HP - High Pressure Safety Injection. Success requires that one of the three safety injection pumps deliver flow from the RWST to the RCS in response to a safety injection signal.
3.1.4.1.3.3 L1 - AFWS Actuation and Secondary Cooling. See discussion under Small LOCA in Section 3.1.3.3.3.

3.1.4.1.3.4 O3 - Operator Cooldown and Depressurize without AFS If auxiliary feedwater cooling should fail but high pressure injection is successful, the scenario will proceed in one of two directions depending upon the ruptured tube flow as follows:

If ruptured tube flow rate is sufficient to maintain the level in the SG at > 5% NR, then the operators will cooldown the RCS to below the safety valve pressure setting, by dumping steam from the ruptured generator according to procedure EOP ECA 3.1 step 11. When the RCS is sufficiently subcooled with respect to the SG temperature and pressure, the operators will then begin depressurizing the RCS using one PORV.

If the ruptured tube flow rate from the RCS is insufficient to maintain level in the steam generator, the operator would follow the direction given by the Heat Sink Status Trees (F-0.3) and initiate bleed and feed (FR-H.1).

Plant specific MAAP runs for the case of a double ended tube rupture and no AFS feed to any steam generator, indicates that the level in the ruptured steam generator increases following reactor trip and would in fact result in an overfill within approximately 50 minutes, if no action is taken (ie. the break flow rate is adequate to maintain the NR level above 5%). The former of the above two scenarios is therefore chosen for modelling purposes.

If event O3 is challenged and fails, the ruptured steam generator would overfill, resulting in water passing through the atmospheric relief/safety valves and increasing the likelihood of a stuck open valve. Furthermore, core damage is assumed to occur, since without positive action on the part of the operator to open at least one PORV, the heat removal via the break is insufficient to remove all decay heat, and the RCS pressure will begin to increase, eventually exceeding the high pressure injection pump shut off head.

The probability of operator failing to respond appropriately for this event is judged to be similar to that evaluated for bleed and feed.

Given success of event O3 steam generator, overfill is averted and RCS will be subsequently cooled down to atmospheric pressure with the aid of RHR (challenged in event O5).

3.1.4.1.3.5 OS - Isolation of Ruptured Steam Generator - Early. For operators to carry out proper actions in the remainder of this event tree they must identify and isolate the ruptured steam generator in preparation for terminating the leak. First it is important to note that the model deals only with leaks beyond the capability of one charging pump. Smaller leaks are often more difficult to identify but have no discernable impact on risk. Larger leaks give many solid indications, such as high radiation in main steam and blow down lines, high steam generator level and steam flow/feed flow mismatch. Once identified there is a high probability of the operator taking action to isolate the steam generator due to extensive training. Should the operator fail to isolate the steam generator early, the leak cannot be terminated (event O4) and steam generator overfill is assumed to occur, increasing the likelihood of a stuck open atmospheric relief or safety valve (challenged in event SO).

Isolation is not achieved if:

1. Any atmospheric relief or safety valve sticks open. It is assumed that the ARV will lift with some small probability of the SRV being demanded also.

2. The main steam isolation valve and bypass line on the faulted steam generator fails to close and is isolated by securing the steam dump system and allowing the main steam check valves on the intact steam generators to block reverse flow from the faulted steam generator.

3. Feedwater is not isolated to the ruptured steam generator. This would cause the level to continue to rise and will lead to water being released through the atmospheric relief valves or safety valves increasing their likelihood of sticking open.

4. Blow down line fails to isolate

5. Operator failure to isolate turbine driven pump steam supply feed MS-41 and MS-42 . This only applies if both motor driven AFS pumps are unavailable and the turbine driven pump is being used for secondary side heat removal.

3.1.4.1.3.6 O4 - System Depressurization. The success of O4 depends on the operator depressurizing and stabilizing the reactor coolant system at a pressure below that of the ruptured steam generator. As in the case of event O3, described above, success of this event requires that the operators take action in sufficient time to prevent SG overfill.

Given success of L1 the operator controls the RCS temperature and pressure using the AFS and atmospheric relief valves on the non ruptured steam generators, condenser steam dumps together with pressurizer spray or PORVs. For analysis purposes the steam dump is assumed to be unavailable and success is assumed to require one atmospheric relief valve and one pressurizer PORV and its associated block valve to open.

If event O4 fails, the ruptured steam generator is assumed to overfill resulting in water passing through the atmospheric relief or safety valves and increasing the likelihood of a stuck open valve. Event O4 is not challenged given a preceding failure to isolate the steam generator (OS) since in this case steam generator overfill is assumed.

<u>3.1.4.1.3.7</u> <u>O5 - RCS Cooldown, Depressurization - Late.</u> Operator failure to achieve early cooldown (Event O4 and Event O3) or failure to isolate the steam generator (Event OS or SO), leads to a continuous loss of RCS inventory through the steam generator relief valves. However, late cooldown coupled with RCS make up from the high pressure injection and late steam generator isolation can still assure stable conditions, as discussed above. Alternatively, if late steam generator isolation is not successful, cooldown of the RCS to atmospheric pressure using RHR, coupled with RWST make up, can still achieve successful accident mitigation.

Event O5, therefore, models the initiation of late controlled cooldown (< 100 °F per hour) of the RCS using secondary side cooling (AFS and 1 atmospheric relief valve). Cooldown must begin within approximately 8 hours after the SGTR event to ensure that atmospheric pressure can be achieved before the RWST supply is drained.

Several different models are developed for this event depending upon preceding events.

a) O5A/B - (Success of HP, L1, OS ...and failure of O4). In this case success requires continuous make up to the RCS (provided by HP) until the RCS pressure is reduced to the SRV or ARV set point at which time the valve is challenged to close (Event SO). If SO closes, the LOCA is terminated and stable conditions are achieved with heat being removed via the intact steam generators. The failure contributors considered are:

   - Failure of the operator to initiate normal RCS cooldown (excludes cognitive operator response due to preceding success OS).

   - Failure of one SG relief valve on non ruptured generator to open.

b) O5E - (Success of HP and L1 but failure of OS). This is identical to O5A/B with the exception that the cognitive operator is included since there have been no preceding operator successes.

c) O5G/H - (Success of L1 and OS.. but failure of O4). Success requires continuous make up to the RCS until the RCS pressure can be reduced to the ARV/ SRV set point. However, since high pressure injection is failed this is not initially available. Following the EOPs the operator is advised to cooldown using the unfaulted steam generators and may eventually be required to blow down all the generators to atmospheric pressure if the LOCA cannot be terminated prior to exceeding 1200 °F core exit temperature. This will cause rapid RCS depressurization and permit accumulators and low pressure pumps to inject.

This event therefore models :

- Failure of the atmospheric relief valves on the 3 non ruptured steam generators to open.

- Failure of the operator to initiate core cooling recovery actions.

d) O52- (HP and O3 success ... failure of L1). In this case cooldown and depressurization is continued by dumping steam from the ruptured steam generator and opening a pressurizer PORV until shutdown RHR cooling can be used (below 350 deg F and 450 psig). This event has been removed from the event tree since its only contributor "failure to initiate RHR" has been transfered to event LR.

e) O53 - (success of L1 .. failure of HP and OS). The contributors to this event are identical to O5G/H. However, the dependencies on preceding failure of OS are different to those associated with O4.

3.1.4.1.3.8 SO - Isolation of Steam Generator - late. This event is challenged following a preceding failure of event OS or O4, which implies the ruptured steam generator is not isolated and/or two phase flow has passed through a relief valve. The outcome of this event determines whether a permanent RCS leak path outside containment exists, which is important for two reasons. First, it determines whether the LOCA is terminated and stable conditions can be achieved without demanding RHR and RWST makeup (given success of O5). Second, in the event of core damage, it determines the mechanism for fission product release outside containment. That is, whether the release is restricted via a cycling ARV/SRV (success of SO) or a direct unrestricted pathway exists (failure of SO).

There are five models developed for this top event:

a) SO1- late isolation of the ruptured SG, given a preceding failure of OS but success of O5. In this there are two contributors to consider:

- Failure to isolate the pathways considered in OS given the additional time available (ie. several hours versus 20 mins). Success of O5 implies no cognitive response failure contribution in this event.

- SRV passes two phase flow and sticks open.

b) SO2- late isolation of ruptured generator given success of OS and failure of O4. In this case only the safety valve opening and sticking open is considered.

c) SO3- late isolation of ruptured generator given preceding failure of OS and O5. The failure contributions are identical to SO1 except for the cognitive human error dependency due to the failure of O5.

d) SO4- late isolation of ruptured steam generator given preceding success of O3 and OS not challenged. This model includes the same failure modes OS with the exception that isolation of the Auxiliary Feedwater is unnecessary because L1 has failed. Success of O3 implies no operator cognitive response contribution.

e) SO5- late isolation of rupture steam generator given preceding failure of L1 and HP with OS and O3 not challenged. This model is identical to SO4 with the exception that the operator cognitive response contribution is included, since there have not been prior operator successes.

Event SO is not challenge following a preceding failure of event O3, since in these scenarios the operator is deliberately attempting to fault the ruptured SG and an unrestricted release pathway is presumed to exist.

3.1.4.1.3.9 MU - RWST Make Up. In the event that the ruptured steam generator cannot be isolated continued injection to the RCS may be required for an extended period. In order to facilitate this, make up to the RWST from the primary water storage tank (PWST) is modeled in this event. Hardware and manipulative human errors are included. The cognitive error is excluded given the preceding success of O5.

3.1.4.1.3.10 AS - Accumulators. Following failure of high pressure injection in combination with a non-isolated ruptured steam generator, the required make up can be achieved with low pressure systems, given success of event O5. As in the case of small LOCA this is assumed to require 3 of 4 accumulators to inject into the RCS.

3.1.4.1.3.11 LP - Low Pressure Safety Injection. This event is challenged under the same circumstances as event AS and models low pressure injection from the RWST into the RCS using one of two RHR pumps.

3.1.4.1.3.12 LR - Low Head Recirculation available. Following success of late depressurization (and make up if necessary), initiation of RHR in the shutdown cooling mode is required in order to maintain stable conditions and prevent core damage. This event includes the RHR system hardware with the exception the heat removal function which is modeled seperately event RH. The manipulative operator action associated with initiation of RHR is included within this event. However cognitive operator failures are excluded due to the preceding success of LR.

3.1.4.1.3.13 RH - Recirculation Heat Removal. This event models the heat removal via the RHR heat exchangers and is challenged following success of LR. The event models the opening of the RHR heat exchanger CCS and its success is conditional on the success of CCS. The operator action associated with initiation of heat removal is included within preceding events O5 and LR.

3.1.4.1.4 System Interactions

The important frontline system interactions are discussed in Section 3.1.4.1.3. A support system dependency matrix is available in Tables 3.1-23 and 3.1-24. Both frontline and support system dependencies are reflected in the split fraction logic for the SGTR event tree shown in Table 3.1-15.

3.1.4.1.5 Plant Damage States

The binning logic for the SGTR accident sequences is shown in Table 3.1-16 and explained further in Section 3.1.6.

Note that in the event of a failure of SO or OS (with no challenge to SO), or failure of O3, a permanent containment bypass for fission product release exists (PDS48A). For cases where a temporary fission product release path exists until the RCS pressure drops below the cycling SRV set point (success or bypass of SO or O3), a separate plant damage state (PDS48B) is defined. Note that all core damage sequences are binned to PDS48A or PDS48B and thus the status of containment systems following core damage (eg. Fan Coolers, Containment Spray) is not considered in the SGTR binning process.

3.1.4.2 Loss of Offsite Power

3.1.4.2.1 Introduction

A loss of offsite power (LOSP) initiating event has been defined as failure of the 138kv and 13.8 kv feeders to IP-2 or switchyard faults. A subsequent undervoltage on busses 5, 6, and hence 5A and 6A, will lead to unit trip and a blackout signal. All three diesel generators will receive start signals and will load all four de-energized 480-v ac busses, 2A, 3A, 5A and 6A.

Given the diesel generators operate successfully and there is no subsequent SI signal, the progression of events is identical to that already considered for the General Transient event tree discussed in section 3.1.3.4. However LOSP merits separate consideration since application of the usual simplifying assumptions, which do not address time phased recovery actions, would lead to very conservative results in this case.

The LOSP event tree is shown in Figure 3.1-6. Initial electric power and other support system states are evaluated in the electric power and auxiliary system event trees. Specific events have been included in the LOSP tree to account for recovery of AC power from the offsite grid and the Gas Turbine units located at the Indian Point Station. The event tree contains events, listed below, which influence the accident progression pre and post core damage. Those events which are included solely for the latter purpose are identified with (c).

P1 - Offsite Power Recovery within 1/2 hour
PV - PORVs Open and Reclose
ST - Power on Bus 5A, 6A or 2A and 3A
T1 - Gas Turbine Start and Load within 1/2 hour
L1 - Auxiliary feedwater and Secondary Side Cooling
P2 - Offsite Power recovery within 60 mins
T2 - Gas Turbine Start and Load within 60 mins
P3 - Offsite Power Recovery within 3 hours
T3 - Gas Turbine Start and Load within 3 hours
SG - Steam Generator Level Control
BV - Close PORV Block Valve
LS - RCP Seal Cooling
C1 - No Core Uncovery before Recovery of offsite power
C2 - No Core Uncovery before Gas Turbine Start and Load
VF - No vessel failure before ac power recovery[c]
CF - No containment failure before ac power recovery[c]
SE - Recovery of Essential Service Water
SN - Recovery of Non-Essential Service Water
CO - Recovery of Component Cooling
RW - Refueling Water Storage Tank

O1 - Primary Bleed Cooling
HP - High Head Safety Injection
FC - Containment Fan Coolers
HR - High Head Recirculation
DP - Rapid Depressurization before vessel failure[c]
LP - Low Head Injection Late[c]
LR - Low Head Recirculation Late[c]
RH - Recirculation Heat Removal
CS - Containment Spray[c]

3.1.4.2.2 Specific Modeling Considerations and Assumptions

3.1.4.2.2.1 AC Power and SI signal status

The progression of events following LOSP are controlled both automatically or procedurally, depending on which of the subsequent set of conditions prevail so as to ensure adequate time for all required operator actions and prevent diesel generator overload.

a) no SI signal and at least one of the 480-v ac busses energized.

b) a coincident SI signal (real or spurious) and at least one 480v-ac bus energized.

c) failure of all three diesel generators to start and energize their appropriate buses, ie. station blackout.

d) both station blackout and an SI signal, ie. (b) and (c) above.

Three potentially risk significant items have been identified which are affected in someway by these conditions. Each of these items is discussed below and the LOSP event tree has been structured to facilitate their evaluation.

1. Tripping and reloading of 480V AC bus motor loads (except MCCs)

Under all loss of offsite power conditions, all motor loads on the 480V-AC buses are tripped. If no SI signal or station blackout condition exists (condition (a)), service water pumps aligned to the essential header, the CCW pumps, the auxiliary feedwater pumps and the fan cooler units will automatically start.

In the event of an LOSP with coincident SI signal (condition (b)) the diesel generator load sequencer starts the motor driven auxiliary feedwater pumps, the essential service water pumps but does not restart the CCW pumps or the SW pumps aligned to the non essential header. The CCW pumps directly support the reactor coolant pump (RCP) seal cooling as they provide cooling to the thermal barriers and they also provide cooling to the charging pumps. Delay of the CCW pump initiation until ECCS Recirculation phase therefore eliminates one mode of RCP seal protection and degrades the ability to provide charging flow, including seal injection. From a risk perspective, RCP seal LOCA is a prime concern where there is not an existing failure of the RCS ie. due to a stuck open, non-isolable PORV. To compensate for the unavailability of CCW two actions are required in the procedures (E-O step 4f). One action is to start a charging pump on high speed (delays the need for external cooling) and the second involves manual alignment of the City Water to provide cooling to the charging pumps.

2. Omission of Immediate Gas turbine recovery for Partial Blackout

Under the conditions of total station blackout, with or without an SI signal (condition c and d), the EOPs explicitly call for the operators to restore AC power by starting GT 1, 2 or 3 during the early stages of the transient (ECA-0.0, step 6). Under conditions in which at least one 480V-AC bus is energized, (condition a), early use of the GTs is inferred (ES-0.1, Step 9) but not explicitly called for. Under conditions with an SI signal and at least one bus energized (condition b), the EOPs do not address starting the GTs until after SI termination (ES-1.1, step 23).

Regardless of the specific procedure which is being implemented operators are well aware of the value of the Gas Turbines and would probably attempt to start them at the earliest time, having first established that one or more diesel generators cannot be emergency started using SOP 27.3.1. However the procedures do indicate different priorities under each specific condition and there may well be more of a delay in starting the GTs under conditions (a) and (b) than under conditions (c) and (d). Based on discussions and procedure walkthroughs with IP2 Operations personnel, we have assumed a delay time after LOSP before attempting to start GT1 under (c) or (d) of 10 minutes, whereas under conditions (a) or (b) it is assumed to be 20 minutes. The delay time between attempting to start GT1 and GT2 or 3 given GT1 failed is take to be 15 minutes in all cases.

In the event of loss of all three diesels (station blackout) with or without SI (cases c and d) the operator is instructed to place equipment switches associated with CS, SI, CFC, AFS, CCS, RHR and non essential preference loads in pullout (ECA 0.0 step 7). When power is restored, one SW pump on the essential header is started to support any running diesels. SIS pumps, RHR pumps, fan coolers and one charging pump (to provide seal injection) are also started (ECA 0.1 or ECA 0.2, steps 1 thru 14).

4. Emergency Diesel Generator (EDG) Building Ventilation Capacity

Five ventilation fans, powered from two of the EDGs, provide ventilation and cooling of the EDG building. The number of fans required to maintain the building below the temperature needed for proper EDG operation depends upon the number of diesels operating, their electrical loading (and subsequent heat output) and the outside ambient air temperature. In the event of an SI signal the electrical loading may be significantly greater than would be the case without SI since additional equipment will be operating. In this model electrical loadings associated with SI condition (conservative case) have been assumed.

3.1.4.2.2.2 Tripping and reloading of 480V-AC MCCs

Under all LOSP conditions all 480V-AC breakers, except those feeding valve motor control centers 26A /26AA, 26B/26BB and 26C (new) are tripped. When AC power is re-established by starting the diesel generators, essential loads, including the diesel generator auxiliaries, are then re-energized by the operator locally reclosing the 480V AC breakers feeding MCCs 24A (new), 27A (new) and 29A (new) and lighting transformers 22 and 23. This operator action is included in the EPS system model.

A recent plant modification has removed the requirement, under specific conditions, for operators to individually open breakers feeding non essential loads on MCCs 24, 27 and 29 before reconnecting the MCCs to their 480V buses.

3.1.4.2.2.3 Recovery of Diesel Generators

No credit is given for recovery of initially failed diesel generators due to additional modeling complexity that would be introduced, and the limited benefit in terms of reducing the overall core damage frequency.

3.1.4.2.2.4 Recovery of AC power from offsite and Gas Turbines.

Prior to core damage the recovery of AC power from offsite and the Gas turbines are treated individually to facilitate future importance sensitivity studies on core damage frequency. Following core damage the recovery model of AC power from both sources is combined to limit the overall size of the event tree.

3.1.4.2.2.5 Loss of HVAC

In the event of station blackout or even less severe conditions, loss of HVAC leading to adverse temperature in Control Rooms, Switch Gear Rooms and Pump rooms has been found to be an important factor in other PRAs. An evaluation of this issue at IP2 has led to the conclusion that adverse temperatures will not occur rapidly following loss of HVAC and can be avoided completely by operators taking proceduralized actions, such as opening room and cabinet doors, to allow natural circulation. The only plant area where this conclusion was not found to be valid is the EDG Building, as inferred above, and the EDG Building HVAC system is consequently modeled explicitly.

3.1.4.2.3 System and Operator Function

The top events for the Loss of Offsite Power event tree, P1 through CS are described in detail to provide an understanding of the systems and operator functions involved. The numerical calculations of each top event are are performed in the individual systems analysis described in Section 3.2.

3.1.4.2.3.1 P1 - Offsite Power Recovery within 1/2 hour. Within the first 1/2 hour after the LOSP event, the probability of a RCP seal LOCA due to loss of all cooling is very small and the secondary side SG inventory is still sufficient to remove most of the decay heat. (Bleed and feed is still viable up to 45-50 minutes and the PORVs do not lift automatically until about 1 hour after the initiating event. Thus, if offsite power is recoverd within 1/2 hour, the accident is no more severe than a loss of normal feedwater transient, which is modeled elsewhere.

3.1.4.2.3.2 PV - PORVs Open and Reclose. Following the initial Loss of Offsite Power transient, the PORVs may be challenged, in which case at least one valve may fail to reclose. This is assumed to lead to the initiation of an SI signal, and would represent a consequential small LOCA if the associated block valve was not closed by the operator. This event is therefore logically constructed as follows:

PV = (PORV Challenge Rate) x (PORV fails to reclose)

3.1.4.2.3.3 ST - Station Black Out. This event delineates station blackout (SBO) from non SBO sequences. Following a loss of offsite power, SBO will occur if all three diesel generators fail to start or run for their required mission. Failure may occur due to random failures of the diesel generators or their support systems which include Essential service water, DC power and the EDG Building Ventilation system. SW and DC support systems have previously been addressed in the support system event trees. EDG Building Ventilation has not been previously addressed and the contribution to SBO is therefore included within this function. Apart from the obvious implications of SBO on equipment operability, as mentioned above, the operating procedure in effect and the subsequent timing of AC power recovery utilizing the Gas Turbines are dependent upon whether or not there is an SBO.

3.1.4.2.3.4 T1 - Gas Turbine Start and Load within 1/2 hour. Gas Turbines (GT) Units 1 and 3 are capable of being black started from the CCR, although the procedure requires a Nuclear Plant Operator to be present at the GTs during start up. Gas Turbine 2 currently has limited black start capability and thus no credit is given for this unit in the analysis. The availability of power from the gas turbines within 1/2 hour is dependent upon the specific operating procedure which in turn, is determined by the status of AC power on the 480V buses. In the event that power is restored to the de-energized 480V buses within a 1/2 hour, the severity of the transient is diminished to that of a loss of normal loss of feedwater transient, as discussed under event P1.

3.1.4.2.3.5 L1 - Auxiliary Feedwater and Secondary Side Cooling. The success criterion for the auxiliary feedwater system depends on the start of one motor driven pump or the turbine driven pump. The automatic signal to start auxiliary feedwater pumps in this event will come from a loss of offsite power with unit trip and no SI. In the event of an SI signal, the motor driven AFS pumps would strip and reload. Both the turbine driven and the motor driven pumps would also start on low level in two of four steam generators.

Secondary side cooling is achieved by automatically or manually opening atmospheric relief valve(s) associated with steam generator(s) receiving auxiliary feedwater. Heat is also adequately removed by safety relief valves which are self actuating, or condenser steam dumps. Due to the high level of redundancy and lack of any necessity for support systems, secondary steam relief valves are not explicitly.

Heat removal from the primary system can be provided by one steam generator. Given these conditions, the reactor core will be cooled by forced flow or by single or two-phase natural circulation to the steam generator.

If AFW and Secondary Cooling are successful and there is no consequential LOCA, the accident is considered to be successfully mitigated.

If the AFW initially fails to operate, the steam generators will begin dry out and the RCS will heat up leading to opening of the primary PORVs after about 1 hour, and subsequent loss of RCS inventory. In the absence of any AFW, successful bleed and feed must be established before the steam generator level drops below 10.4 ft, which based on plant specific MAAP calculations will occur approximately 45 minutes after the initiating event. However, even if it was not possible to initiate Feed and Bleed within this period, subsequent AFW recovery (ie. due to restoration of ac power to motor driven pumps from the grid or GTs) may still prevent core uncovery, which would not occur until well after 1.6 hours (assumes SORV).

Following initial failure of Auxiliary Feed Water, a challenge to the PORVs and a stuck open valve becomes more likely, requiring high head injection for accident mitigation.

It is therefore assumed that bleed and feed is demanded following initial failure of AFW. However, in order to take credit for the potential for recovering AFW after the 45 minutes (bleed and feed initiation time with no AFW) but well before core damage, the event tree model first challenges AC power recovery within one hour (events P2 and T2). This is conservative, since AFW recovery by itself after 1 hour may be adequate to prevent core damage. However, considering the complications associated with modeling the stuck open PORV/SRV, block valve closing, and AFW conditional recovery the potential benefits with respect to overall core damage frequency do not warrant evaluation.

In the event of a station blackout, the turbine driven AFS pump and associated valves and controls will continue to function, supported by DC power (Bus 22) and bottled nitrogen. The battery capacity is sufficient for 3 hours operation, following which the operators can take local, manual of the turbine driven pump. This is considered further under event SG.

As discussed above, elevated temperatures in the AFW Building due to loss of room ventilation for any reason, including station blackout, are not a risk significant issue.

3.1.4.2.3.6 P2- Offsite Power Recovery within 60 mins. Given initial failure of the Auxiliary Feedwater (L1) AC power must be restored within 60 minutes (see discussion under L1). Therefore, to represent the support system availability in the most realistic manner possible, this event models the restoration of offsite power to the 480V buses between 30 minutes and 60 minutes after LOSP.

3.1.4.2.3.7 T2 - Gas Turbine Start and Load within 60 mins. This event models the recovery of power to the de-energized 480V AC buses from GT1 or GT3, between 30 and 60 minutes after LOSP. The purpose for including this event is the same as for P2.

3.1.4.2.3.8 P3 - Offsite Power Recovery in 3 hours. This event models the recovery of offsite power between 60 mins and 3 hours and is only challenged for station blackout sequences with failure of the gas turbines and success of the turbine driven AFS pump. Failure to restore ac power within 3 hours will result in depletion of battery D22 and a requirement to control the pump locally. Furthermore, since all other batteries may be depleted within 2 hours of LOSP, all 118VAC power for instrumentation are assumed failed by 3 hours. The consequences of this are modeled in event SG.

3.1.4.2.3.9 T3 - Gas Turbine Start and Load within 3 hours. The definition and purpose of this event is similar to P3.

3.1.4.2.3.10 Steam Generator Level Control. This event is challenged following station blackout with no AC power recovery within 3 hours. As discussed under event P3, DC power will be depleted and the operator will be required to control the AFS turbine driven pump manually, relying on remote pneumatic SG level indication. Event SG therefore models the failure to control the AFS turbine driven pump and maintain SG level under these adverse conditions.

3.1.4.2.3.11 BV - Close PORV Block Valve. This event models failure to isolate a stuck open pressurizer PORV (event PV). The event includes both operator and block valve failures. Failure to isolate the stuck open PORV results in a consequential small LOCA and MAAP analysis indicates over 1.6 hours are available to initiate safety injection prior to core uncovery. The current LOSP analysis assumes 60 minutes are available.

3.1.4.2.3.12 LS - RCP Seal Cooling. This event represents the availability of cooling and injection to the RCP seals from either the Charging Pumps or the Component Cooling System (CCS). Following loss of offsite power, RCP seal injection from the Charging Pumps and Component cooling to the RCP thermal barriers are initially lost. High temperature reactor coolant begins to flow out from the loops and flash within the seals resulting in the potential for seal failure. Under non SI conditions, CCS to the thermal barriers is automatically restored and cools the RCS flow prior to entering the seals, removing the seal LOCA potential. However, the presence of coincident SI conditions or CCS/power supply failures may prevent timely restoration of CCS, as discussed earlier. In such cases, RCP seal LOCA may be prevented by the operator restarting a charging pump and establishing seal injection according to the EOP instructions. Since the charging pump drives are normally cooled by CCS, which is not available, the operator must initially set the charging pump flow controller to maximum, which extends the pump operating time without cooling (Ref 3.1-6), and establish a cooling water supply via the City Water/CCS cross connect. With the pumps at minimum speed the operating time prior to damage would only be a few minutes.

The logic for this event therefore is represented by:

LS = (failure of CCS) x (failure of charging system + operator error)

With power initially available from a diesel generator to at least one bus providig power to the CCS pumps (5A, 2A or 6A), the CCS is challenged in the auxiliary systems event tree and its probability of failure at LS is therefore 1 or 0, as defined by support state condition being evaluated. However, in the case of an initial station blackout (no diesels available) the CCS is not challenged in the Auxiliary Systems Event Tree (ref 15.) and therefore can be challenged within event LS, if AC power is recovered from the GTs or offsite. The probability of seal LOCA within a 1/2 hour following LOSP is not significant and therefore 1/2 hour is assumed to be the time available to re-establish RCP seal injection or cooling. Otherwise a potential for seal LOCA is assumed to exist and is evaluated by subsequent event tree headings.

3.1.4.2.3.13 C1 - No Core Uncovery before Recovery of Offsite Power. In the event of a failure of RCP Seal Cooling (event LS) there is the potential for seal failure. The degree of seal damage and the resulting leakage rate (which determines the subsequent time to core damage) are both time dependent variables. In order to properly account for the impact of offsite power recovery at various times on the potential for core damage following a seal LOCA, the probability of core uncovery due to seal failure versus time after loss of seal cooling was first derived using the data available (WCAP-10541, Ref. 3.1-14), and was then combined with the IP2 offsite power recovery model. The result is a probability of core uncovery prior to recovery of offsite power (see Section 3.2).

Note: In the event of success of this function it is not possible to distinguish between those cases in which offsite power was recovered in time to prevent the occurrence of seal LOCA occurrence and those cases in which power recovery occurred prior to core uncovery (ie. in time to initiate high head injection). Thus for the purpose of further analysis it assumed that a seal LOCA has occurred.

3.1.4.2.3.14 C2 - No Core Uncovery before Gas Turbine Start and Load. Similar event to C1.

3.1.4.2.3.15 VF - No Vessel Failure Offsite Before AC Power Recovery. This event is challenged following a station blackout and failure to recover AC power prior to core damage. It models the likelihood of offsite power recovery or GT start in the interval between core damage and core slump. During this period restoration of injection would prevent vessel failure.

3.1.4.2.3.16 CF - No Containment Failure before AC Power Recovery. This event is challenged following a station blackout and failure to recover AC power prior to vessel failure (VF). It models the likelihood of offsite recovery or start of a Gas Turbine in the interval between core slump and containment failure. During this period restoration of injection/recirculation, heat removal, containment spray may prevent containment faiure and reduce the radionuclide release.

3.1.4.2.3.17 SE - Recovery of Essential Service Water. The Essential Service Water is initially challenged in the Support System Event Tree model under event SA (see section 3.1.5). This system may have unavailable at that time due to loss of all AC power or a combination of service water and AC power failures. Following successful AC power recovery in the LOSP Event Tree, the system is challenged once again (taking care to account for any prior Essential SW failures which might have occurred under event SA).

3.1.4.2.3.18 SN - Recovery of Non-Essential Service Water. The Non-Essential Service Water is initially challenged in the Support System Event Tree model under event SB (see Section 3.1.5). This system may have unavailable at that time due to loss of all AC power, combination of service water and AC power failures. Following successful AC power recovery in the LOSP Event Tree, the system is challenged once again (taking care to account for any prior Non-Essential SW failures which might have occurred under event SB).

3.1.4.2.3.19 CO - Recovery of Component Cooling System. The Component Cooling System is initially challenged in the Support System Event Tree model under event CC (see Section 3.1.5). This system may have unavailable at that time due to loss of all AC power, combination of service water and AC power failures. Following successful AC power recovery in the LOSP Event Tree, the system is challenged once again (taking care to account for any prior Component Cooling Water failures which might have occurred under event CC).

3.1.4.2.3.20 RW - The Refueling Water Storage Tank Supply. See discussion under Large LOCA in section 3.1.3.1.3.1.

3.1.4.2.3.21 O1 - Primary Bleed Cooling. See discussion under General Transient in Section 3.1.3.4.3.7.

3.1.4.2.3.22 HP - High Head Safety Injection. See discussion under General Transient in Section 3.1.3.4.3.6.

3.1.4.2.3.23 FC - Containment Fan Coolers. See discussion under Large LOCA in Section 3.1.3.1.3.4.

3.1.4.2.3.24 HR - High Head Recirculation. See discussion under Medium LOCA in Section 3.1.3.2.3.9.

3.1.4.2.3.25 DP - Secondary Side Rapid Depressurization. In the event of a station blackout with no AC power recovery, the EOPs require the operators to manually depressurize the steam generators to 170 psig, by dumping steam at the maximum rate using the atmospheric steam dumps. This is also directed separately by the EOPs in response to indication of inadequate core cooling. Success of this event will reduce the RCS to a lower pressure regime and permit low pressure injection prior to vessel failure.

3.1.4.2.3.26 LI - Low Head Injection Late. See discussion under medium LOCA in Section 3.1.3.2.3.11.

3.1.4.2.3.27 LR - Low Head Recirculation Available Late. This event models low pressure recirculation from the containment using one of two RHR pumps, or one of two recirculation pumps, following core damage. Following vessel failure the recirculation pumps are assumed to have failed due to adverse conditions in containment. The rationale for its inclusion is identical to that described above for event LI. The event is not challenged when high head recirculation or low head injection has failed.

3.1.4.2.3.28 CS - Containment Spray. See discussion under Large LOCA in Section 3.1.3.1.3.8

3.1.4.1.4 System Interactions

The important frontline system interactions are discussed in Section 3.1.4.2.3.3. A support system dependency matrix is available in Tables 3.1-23 and 3.1-24. Both frontline and support system dependencies are reflected in the split fraction logic for the Loss of Offsite Power event tree shown in Table 3.1-17.

3.1.4.2.5 Plant Damage States

The binning logic for the Loss of Offsite Power accident sequences is shown in Table 3.1-18 and explained further in Section 3.1.6.

3.1.4.3 ATWS Events

3.1.4.3.1 Introduction

The analysis in this section makes extensive use of the recent Westinghouse Owners Group study of ATWS events, documented in WCAPs 11992 and 11993 (Refs. 3.1-2 and 3.1-8). This is considered to be appropriate in that the WCAP analysis is backed by extensive thermal hydraulic calculations on a generic basis.

The example plant is a typical Westingouse 4-loop plant with 51 series steam generators. However, various sensitivity studies were performed for parameters which were identified as important contributors to ATWS CDF, to establish for Westinghouse PWRs as a class, conformance with the ATWS rule basis. The reference model incorporates two AFS motor driven pumps and one turbine driven AFS pump, two pressurizer power operated relief valves (PORVs) and three pressurizer safety valves. An 18 month core design is modeled and quantified as the base case.

The event tree constructed in the WCAP has been modified according to some specific design features of the IP2 plant and the requirements of the level 2 PRA being developed in this case. The IP2 ATWS event tree, shown in Fgure 3.1-7, uses the following symbols to identify system and operator functions:

IE - Anticipated Transient
RT - Reactor Trip
PL - Power Level > 40%
TT - Turbine Trip
L1 - Auxiliary Feedwater
PR - Pressure Relief
SR - Secure Pressure Relief
RW - RWST supply
BR - Emergency Boration
O2 - PORV bleed for SI boration
HP - High Pressure Injection
MD - Manually Deenergize Control Rod Drives
FC - Fan Coolers
HR - High Pressure Recirculation
LI - Low Head Injection
LR - Low head Recirculation
RH - Recirculation Cooling
CS - Containment Spray

An ATWS event is composed of two different events. The first is an initiating event, usually an anticipated transient, which would normally generate a reactor trip signal, and the second is the failure to insert the rod cluster control assemblies into the core following the reactor trip demand.

Limiting ATWS initiating events (IEs) are those which result in highest RCS pressures. These are heatup events resulting from the degradation of the heat transfer capability between the primary and the secondary systems with the RCS boundary initially intact. Examples of such IEs, as shown by ATWS analyses for Westinghouse PWRs (e.g., WCAP-8330, Ref. 3.1-9) are the loss of load with subsequent loss of all main feedwater.

The magnitude of the heatup and the resulting pressure increase are determined by the ability to maintain primary to secondary heat transfer, the primary pressure relief capacity, and the inherent shutdown characteristics of the reactor (reactivity feedback). The first item depends on the availability and the amount of feedwater flow (Main or Auxiliary) and ability to isolate main steam, the second depends on the total primary relief capacity including the abilty to use the PORVs to supplement the safety relief, and the third is a function of the time during the fuel cycle for a specific reactor.

The effect of reactivity feedback on coolant temperature increase during an ATWS event is an important element in calculation of the peak pressure. Details of the methodology to derive heatup and shutdown characteristics, or "critical power trajectories," are presented in Appendix B of WCAP-11992 (ref 3.1-8). The critical power trajectory is defined as the locus of conditions, in terms of core inlet coolant temperature versus reactor power, which result in a peak primary pressure of 3200 psig. Exceeding this pressure limit (ASME Boiler and Pressure Vessel Code Level C Service Limit Criterion) was assumed in the IPPSS to lead to primary system leakage (equivalent to small LOCA) and but is more conservatively assumed to lead to a LOCA beyond the capacity of the ECCS in this analysis.

For initiating events from power levels less than 40 percent, the peak pressure attained in the primary system is not predicted to exceed the allowable stress level of components in the Reactor Coolant System (RCS) regardless of the specific initiating event. For these events, automatic (AMSAC) or early manual turbine trip and AFW initiation is not required to prevent exceeding 3200 psig.

For IEs from power levels greater than 40 percent, availability of main feedwater is an important consideration. In this analysis, as in the IPPSS, no credit is taken for potential availability of main feedwater (MFW) for the following reasons:

1. At IP2, a Safety Injection (SI) signal results in isolation of MFW. All depressurization events result in generation of a SI signal.

2. All excessive cooldown events result in the generation of a main feedline isolation signal. Thus, all of these events ultimately result in a heatup sequence.

3. All power excursion transients are beyond the capability of the MFW system to maintain steam generator level.

With the loss of MFW and failure of the reactor to trip, the primary system would start a rapid heat up, while the levels in the steam generators would begin to drop from boil-off. As the SG water level droped to the point that the tubes were exposed, primary to secondary heat transfer would be reduced further. RCS temperature and pressure would continue to increase as the pressurizer filled and eventually released water through the PORVs and the safeties. The volumetric relief capacities of these valves is reduced when the pressurizer fills and water is passed instead of steam.

Depending on the reactivity feedback conditions, core power will begin to reduce, and if the reactor were in the automatic control rod mode, control rods would automatically begin to insert as the primary heat began, thereby reducing power and preventin overpressurization.

Following failure of automatic reactor trip, several mechanisms are available to the operator for plant shutdown. He is instructed to first initiate manual trip. A manual reactor trip signal is processed both directly to the trip breakers and through the protection logic. If this action is not successful, he is instructed to de-energize 480V-ac buses 2A and 6A for 10 seconds to trip the MG sets (EOP E-0). If the reactor is still not tripped, another procedure is activated (FR-S.1) where he is told to manually insert rods and then to trip the MG sets. He is then instructed to verify or manually trip the turbine, verify or manually start the AFW pumps, and start emergency boration of the RCS.

Standard boration uses the charging pumps through the Chemical Volume Control System (CVCS) with borated water either from the the RWST (normal Boration path) or the emergency boration path using boric acid transfer pumps. Should this fail, Emergency Boration is performed in the SI mode, which requires reactor depressurization to achieve sufficient flow.

If all these methods fail to shut down the reactor, an operator is dispatched to locally trip the control rod power at the motor generator set supply breakers. Local trip of the turbine is also performed should all previous attempts at manual turbine trip, closure of the MSIVs, turbine runback, and local closure of the MSIVs fail.

3.1.4.3.2 Modeling Assumptions

1. Core damage will occur due to RCS leakage beyond ECCS capacity, if RCS pressure exceeds the ASME Boiler and Pressure Vessel Code Level C service limit stress criterion for Westinghouse plants, set at 3200 psig.

2.All operator actions to achieve subcriticality must be completed within 10 minutes from initiation of a reactor trip signal (WCAP-11992).

3. There is insufficient time for the operator to establish maximum AFW flow (from all three pumps at full design flow capacity). The turbine driven AFW pumps (TDAFWP) needs manual actions to deliver any significant amount of flow. Thus, no credit is taken for full AFW flow.

4. No credit is taken for automatic rod insertion by the control system. This is a significant conservatism in that: (1) insertion for the limiting ATWS events (e.g., complete loss of feedwater) is likely, and would originate from the temperature input into the rod control system σT_{in} (= T_{av} - T_{ref}; where T_{av} is the average RCS hot leg temperature and T_{ref} is the temperature at the first stage turbine ; (2) Given automatic rod insertion, the RCS pressure limit of 3200 psig probably will not be reached at all, even if the turbine does not trip - see WCAP-8330).

5. For transients above 40% power, failure to trip the turbine is assumed to cause a LOCA beyond ECCS capacity due to exceedance of the 3200 psig pressure limit, whether or not (manual) rod insertion is successful.

6. All ATWS core damage sequences are ultimately equivalent to either medium/small LOCAs or LOCAs beyond ECCS Capacity with respect to the plant damage state groupings, since they are caused by either exceeding the 3200 psig pressure limit (vessel breach) or failure of secondary heat removal (AFW) that will result in the loss of the RCS inventory through the safety and relief valves (equivalent to medium LOCA).

3.1.4.3.3 Initiators

The IE is a general plant transient that, for the purposes of accident progression analysis, is conservatively assumed to either be a loss of load transient followed by a complete loss of feedwater (WCAP-11992) or a complete loss of feedwater event (WCAP-8330). Its frequency is the sum of all transients, medium and small LOCAs and SGTR. LOCAs and SGTR followed by failure to scram have not been treated individually because of their much lower frequencies, lack of significant potential for exceeding 3200 psig, and the fact that all LOCAs require injection that will eventually shutdown the reactor.

For the purposes of the deterministic accident progression considerations, all transients over 40 percent power are conservatively assumed to be complete loss of feedwater events initiated at 100% power.

3.1.4.3.4 System and Operator Functions

The top events for the ATWS event tree, RT through CS are described in detail to provide an understanding of the systems and operator functions involved. The numerical calculations of each top event are are performed in the individual systems analysis described in Section 3.2.

3.1.4.3.4.1 RT - Reactor Trip Success in this node requires either an automatic insertion of the control rods by the Reactor Protection System (RPS), or a manual scram initiated by the operator.

Procedure E-O (Reactor Trip or Safety Injection) first directs the operator to manually trip the reactor. If manual trip is also unsuccessful, he is then instructed to de-energize AC 480V buses 2A and 6A for 10 seconds and re-energize to trip the MG sets. If the reactor still cannot be tripped, the operator must go to procedure FR-S.1 (Response to Nuclear Power Generation/ATWS) Step 1.

As shown in WCAP-8330 (Figure 4-159), pressurizer pressure with no turbine trip), RCS pressure will reach 3200 psig in about 100 seconds. Thus, it can be said that manual scram will have to be completed within one minute to constitute success. On the other hand, if turbine trip is successful (at 30 seconds from WCAP-8330, manual scram can be performed at a later time. Since the failure of the turbine to trip is taken directly to core damage in the event tree model, more time is actually available to scram the reactor for the branch involving failure or reactor trip and success of turbine trip. In the RT failure branch, turbine trip must be performed in about 30 seconds as called for by the WCAP-8330 analysis.

RPS trip failure may be caused by the logic failure of the reactor trip breakers, or failure of the Rod Cluster Control Assemblies (RCCAs) to move. The manual trip function operates through the shunt coil to the trip breakers. Thus, if the failure of automatic trip is not related to the trip breakers or the RCCAs, then manual scram through the shunt coil is possible.

3.1.4.3.4.2 PL - Power Level > 40% This is a single event representing the fraction of all transients that occur at below 40 percent power (up branch). Transients that initiate at these lower power levels will not result in RCS pressures in excess of 3200 psig, irrespective of any other failures. Consistent with this criterion, AMSAC (ATWS Mitigation System Actuation Circuitry) actuation of turbine trip is not required at these power levels.

3.1.4.3.4.3 TT - Turbine Trip Failure to trip the turbine, following reactor trip failure, is assumed to lead directly to core damage for power levels greater than 40%. The operator is instructed to verify or manually trip the turbine following verification of or manual reactor trip in both procedure E-0 and FR-S.1 (which is entered on failure of reactor trip). For many of the transients, the primary turbine trip signal is generated when either of the reactor trip breakers open. Furthermore there is a high degree of cognitive error correlation between manual scram and manual turbine trip functions. Consequently, following failure of the reactor trip event, AMSAC provides the only independent means of turbine trip.

3.1.4.3.4.4 L1 - Auxiliary Feedwater The IP2 design of automatic AFW actuation is such that the turbine driven pump will get a start signal, but its flow will be effectively zero without operator action for opening the steam supply regulator valve (PCV-1139), and adjusting the steam supply control valve (HCV-1118). Because the question on the amount of feedwater flow impacts the pressure relief requirement, and that the peak pressure will be reached in about 100 seconds in the limiting case, it is assumed that there is insufficient time available to the operator for establishing maximum AFW flow by using both motor driven pumps and the turbine driven pump. Thus, the L1 node only uses one half or one quarter AFW flow depending on whether transient begins below or above 40 percent power, respectively. In the former case, the amount of time for all manual operator actions is 10 minutes.

For the branch below 40 percent power, the WCAP model uses minimum AFW flow with one motor driven or the turbine driven AFW pump (at half or full flow) delivering flow to an unspecified number (which must be assumed to be all) of steam generators. The simplified approximate expression for this branch would be:

AF25% = (MDP1)*(MDP2)*(TDP + operator failure to start and control TDP)

For above 40 percent power, the AFW requirement is at 50 percent of maximum available flow. No credit can be taken for manual actions, and as a result the turbine driven pump in this case. Both motor driven pumps have to start from automatic signals which may result from an SI signal, low-low SG level or from AMSAC. The simplified approximate expression for these two branches would be:

AF50% = (AMSAC)*(Other auto start logic not shared with RPS) + (MDP1)(MDP2)

3.1.4.3.4.5 PR - Adequate Pressure Relief This node quantifies the likelihood that the peak RCS pressure limit of 3200 psig will be exceeded, and is dependent on a number of parameters such as (WCAP-11992):

- ATWS initiating event
- Initial power level
- Time in cycle that transient occurs
- Reactivity feedback as function of cycle length or as unfavorable exposure time (UET)
- AFW flow
- Pressurizer pressure relief and safety valve capacity
- Automatic or manual rod insertion

The effect of peak RCS pressure is worst during earlier portions of the fuel cycle.

The initiating event chosen for calculation of UET is a loss of load event followed by complete loss of feedwater, which is more severe than the loss of feedwater transient, and is the most limiting ATWS initiating event. The models consider nominal equilibrium conditions (e.g., equilibrium xenon), and then a power search is performed for criticality conditions as a function of core inlet temperature and, if appropriate, RCCA position (for auto or manual rod insertion), assuming a pressure of 3200 psig.

The UET is that time during the core cycle life that the core design critical trajectory is greater than the transient critical trajectory (i.e., available core reactivity feedback is less than the reference analysis). The value of UET is obtained from the intersection of the curve with the C power excess point, presented in Figures B-2A through B-2F of WCAP-11992.

The IP2-specific UET calculation for no rod insertion, 50% AFW flow, both PORV block valves closed, and for an 18 month cycle yielded a UET of 72 days for cycle 10. This UET was also based on a capacity factor of 50%. The UET is inversely proportional to the capacity factor, since it is directly proportional to the amount of burnup. Thus, the final UET obtained for each of the above combinations relative to the event tree model must be adjusted for the actual plant capacity factor. No credit can be taken for manual block valve opening due to insufficient available time.

3.1.4.3.4.6 SR - Secure Pressure Relief When auxiliary feedwater is successful and the reactor is shutdown, the transient can terminated by securing the RCS blowdown. This requires reclosing of any open safety valves and reclosing of the PORVs or manual closure of their block valves. (Both PORVs are assumed to have opened.)

3.1.4.3.4.7 RW - Refueling Water Storage Tank The refueling water storage tank is required to support long term shut down methods using emergency boration or high head injection which are discussed below. (Also see discussion under large LOCA in Section 3.1.3.1.3.1).

3.1.4.3.4.8 BR - Emergency Boration This node represents one of the options available to the operator if reactor trip fails but turbine trip succeeds. The emergency boration path uses MOV 333 and the boric acid transfer pumps to provide boric acid solution to the discharge of the charging pumps. The charging pump suction must first be realigned from the from the VCT to the RWST. Should this method of boration fail, SI boration will be used by starting one SI pump, blocking low pressurizer pressure SI and depressurizing the RCS to 1400 psig. However, for simplification this method has only been modeled when SI is demanded due to failure to secure pressure relief (ie. event SR).

3.1.4.3.4.9 O2 - Primary Bleed for SI Boration This node represents the depressurization of the RCS to below the shut off head of the SI pumps following a preceding failure to trip the reactor (RT) and a failure to secure pressure relief (SR). Two PORVs are required to open and the time for operator action is 10 mins.

3.1.4.3.4.10 HP - High Pressure Injection This node represents injection of borated water from the RWST using an SI pump, following failure of reactor trip (RT) and failure to secure RCS pressure relief (SR). Success of this event will shut down the reactor and provide make up to the RCS.

3.1.4.3.4.11 MD - Manually - De-energize MG Sets Success of this function involves the operators manually tripping the reactor within 10 minutes of transient initiation by locally opening the reactor trip breakers or deenergizing the MG sets.

3.1.4.3.4.12 FC - Containment Fan Coolers. See discussion under Large LOCA in Section 3.1.3.1.3.4

3.1.4.3.4.13 HR - High Head Recirculation. See discussion under Medium LOCA in Ssection 3.1.3.2.3.9.

3.1.4.3.4.14 LI - Low Head Injection - Late. See discussion under Medium LOCA in Section 3.1.3.2.3.11.

3.1.4.3.4.15 LR - Low Pressure Recirculation. See discussion under Medium LOCA in Section 3.1.3.2.3.12.

3.1.4.3.4.16 RH - Recirculation Cooling. See discussion under Large LOCA in Section 3.1.3.2.3.13

3.1.4.3.4.17 CS - Containment Spray. See discussion under Large LOCA in Section 3.1.3.2.3.14

3.1.4.3.5 System Interactions

The important frontline system interactions are discussed in Section 3.1.4.3.4. A support system dependency matrix is available in Tables 3.1-23 and 3.1-24. Both front line and support system dependencies are reflected in the split fraction logic for the ATWS event tree shown in Table 3.1-19.

3.1.4.3.6 Plant Damage States

The binning logic for the ATWS accident sequences is shown in Table 3.1-20 and explained further in section 3.1.6.

3.1.4.4 LOCA Beyond ECCS Capacity

3.1.4.4.1 Introduction

The LOCA Beyond ECCS Capacity event tree (Figure 3.1-8) applies to all reactor coolant system ruptures with blowdown rates greater than a double-ended circumferential break in an RCS loop. The event tree uses the following symbols to identify systems and plant functions:

IE - Initiating Event, LOCA Beyond ECCS Capacity
RW - Refueling Water Storage Tank
LP - Low pressure Injection
FC - Fan coolers
LR - Low Head Recirculation
RH - Recirculation Cooling
CS - Containment Spray

A LOCA Beyond ECCS capacity is assumed to lead directly to core damage. The availability of injection and containment systems are addressed in order to define the resulting states.

3.1.4.4.2 Initiator

The LOCA beyond ECCS Capacity can occur as a result of a random rupture of the reactor pressure vessel or RCS multiple pipework failures. In addition to random failures, catastrophic vessel failures can occur as a result of Pressurized Thermal Shock (PTS) due to a severe overcooling transients. The potential for PTS events at IP2 are discussed in Section 3.1.3.

3.1.4.4.3 Systems and Operator Functions

The top events of the LOCA in Excess of ECCS Capacity (ET-8), events RW through CS are described in detail to provide an understanding of the system and operator interactions as they specifically relate to this event. The numerical calculations of each top event are performed in the individual systems analyses as described in Section 3.2.

3.1.4.4.3.1 RW - The Refueling Water Storage Tank Supply. See discussion under Large LOCA in Section 3.1.3.1.3.1

3.1.4.4.3.2 LP - Low Pressure Injection. See under Large LOCA in Section 3.1.3.1.3.2.

3.1.4.4.3.3 FC - Fan Cooler Units. See discussion under Large LOCA in Section 3.1.3.1.3.6

3.1.4.4.3.4 LR - Low Pressure Recirculation. See discussion under Large LOCA in Section 3.1.3.1.3.5.

3.1.4.4.3.5 RH - Recirculation Cooling. See discussion under Large LOCA in Section 3.1.3.1.3.6

3.1.4.4.3.6 CS - Containment Spray. See discussion under Large LOCA in Section 3.1.3.1.3.8

3.1.4.4.4 System Interactions

The important frontline system interactions are discussed in Section 3.1.4.4.3. A support system dependency matrix is available in Tables 3.1-23 and 3.1-24. Both frontline and support system dependencies are reflected in the split fraction logic for the LOCA Beyond ECCS Capacity event tree shown in Table 3.1-21.

3.1.4.4.5 Plant Damage States

The binning logic for the LOCA beyond ECCS capacity is accident sequences is shown in Table 3.1-22 and explained further in Section 3.1.6.

3.1.4.5 Interfacing Systems LOCA

An Interfacing Systems LOCA is a LOCA in which the water inventory of the RWST injected into the reactor vessel leaks outside the containment and is therefore not collected in the containment sump. This prevents the establishment of a recirculation flow when the RWST is exhausted and by itself cause damage to ECCS equipment due to the adverse environment created in the Primary Auxiliary Building (PAB). Core damage occurs directly as a result of this initiating event and the containment is bypassed. The various pathways by which the RCS is connected to systems outside containment are identified and evaluated in Section 3.2. Due to the unique nature of this event lack of any significant mitigation capability, this event is assigned a single plant damage state PDS 47 (see Section 3.1.6).

3.1.5 Support Systems Event Tree

The original IPPSS treated support system dependencies three ways. The electric power system status was defined by 16 electric power states, ranging from all power available to loss of all AC power. The plant main line models were quantified for each of the 16 electric power states. The plant DC power systems were not specifically analyzed in the original IPPSS because, at the time, the 16 electric power end states were considered to be representative of all possible electric power states including loss of DC power. The effects of loss of DC power were included in the quantification of loss of AC power after loss of offsite power events in the original IPPSS.

The plant actuation system for safety injection was included as a top event in the main line models. The service water and component cooling water systems were evaluated outside the frontline models, and their failure frequencies were included in the top event frequencies for frontline systems affected by their failure.

Later risk analyses have used the concept of support system models to model explicitly the interrelationship between the various support systems and frontline systems. This approach eliminates the need to perform significant amounts of system evaluation outside the plant model and then to incorporate the results into main line systems top events. The updated Indian Point 2 risk analysis model uses the support system model concept embodied within the RISKMAN software. It includes two support system models, a plant electric power model, and an "other support systems" model for the remainder of the support systems. With the use of RISKMAN to define the entire Indian Point 2 model, the need to link electric power states with mechanical support states and to bin the resulting combinations (impact vectors) is eliminated. Each tree is quantified for all of the end states of the tree preceding it, and binning is done only at the final stage to define the plant damage states.

Specific supplemental analyses have been performed to identify each of the support systems at IP2 and determine whether the impact of failure during plant operation can pose a significant risk by causing an initiating event, degrading an accident mitigating system or both. The effects were both qualitatively and quantitatively screened, taking into account the timing of events and the potential for operator recovery actions. The following systems/subsystems were identified and addressed:

- o Station Auxiliary Transformers
- o 6.9kV Buses 5, 6, 2 and 3
- o All 480V AC Buses
- o All 118V AC Instrument Buses
- o All 125V DC Buses
- o ESFAS Trains
- o Essential Service Water
- o Non-essential Service Water
- o IP1 River Water System
- o Component Cooling Water System
- o Instrument Air System
- o HVAC Systems
  - Central Control Room
  - Primary Auxiliary Building
  - Electrical Switchgear Room
  - Auxiliary Feedwater Pump Room
  - Turbine Hall
  - Cable Spreading Room/Electrical Tunnel
- o City Water System

All of the above listed systems were explicitly modeled as support systems in the IPSSS with the exception of IP1 River Water, Instrument Air, HVAC and City Water. As a result of this analysis, treatment of several of the support systems has been changed and loss of EDG building ventilation was also added as a mitigating support system failure (see Section 3.2.19).

3.1.5.1 Dependency Matrices

The first step in developing the Electric Power and Other Systems Model was the preparation of a dependency table for all support systems. This table is also called a dependency matrix because of its properties. Tables 3.1-23 and 3.1-24 are the dependency tables for the support systems and frontline systems respectively. These tables identify the effects of various single failures in support systems on the other systems and components. The column and row titles are the same and represent the various components included in the models. The first column is used to identify the failed component. Reading across the row, one can quickly determine the effects of the identified failure.
A "**" indicates a direct failure as a result of the failed component in the first column.

Those effects that do not result in direct failure are indicated and explained by footnotes in the table. No entry indicates no failure.

The information in Tables 3.1-23 and 3.1-24 was used in the development of the electric power event tree and the other support systems event tree. Guaranteed failures of systems or equipment (represented by a "**"). For example, failure of 6.9-kV Bus 5 results in direct failure of 6.9-kV Bus 2. Bus 2 is normally supplied from the main generator output through the unit auxiliary transformer. On a plant trip (which is assumed for the electric power model), Bus 2 is automatically stripped from the main generator output and transferred to Bus 5. If Bus 5 falls at the same time or shortly after a plant trip, power is guaranteed to be lost to 6.9-kV Buses 5 and 2. In addition to failure of power at Bus 2, failure of power to Bus 5 results in automatic start of the diesel generators supplying 480V Buses 5A and 2A (diesel generators 21 and 22). Note that, on undervoltage at Bus 5, all three plant diesel generators will start, but only the diesels that load Buses 5A and 2A need to supply power. The diesel that supplies Bus 6A (diesel generator 23) will start and idle since Bus 3A will continue to be supplied from 6.9-kV Bus 3.

On loss of power at 480V Buses 5A and 2A, the batteries supplied by these buses (DC Buses 21 and 22) will not have a charger available until the diesel generators start and reload the buses. Therefore, the frequency of failure of these DC power buses is different under these conditions from the frequency when normal power is available.

3.1.5.2 Electric Power Event Tree Model

The top events modeled in the Electric Power model include:

- Power to the nonvital buses from the offsite grid.
- Nonvital AC power buses 2, 3, 5 and 6.
- The four vital DC buses 21, 22, 23 and 24.
- The vital 480V AC buses 2A, 3A, 5A and 6A.
- The emergency diesel generators 21, 22 and 23
- The emergency diesel generator fuel oil system.

Figure 3.1-9 is the event tree that represents the electric power systems model for Indian Point 2. The event tree split fraction logic is shown in Table 3.1-25.

The need for a separate electric power systems model grew from a need to present a more complete analysis of the plant electric power systems. Because of the complex interrelationships among the various sources of electric power, an event tree was developed to portray these relationships.

The Indian Point 2 electric power model the major sources of AC and DC power to the plant and the way in which these various sources interact.

The top events in the electric power model are described in the following sections.

3.1.5.2.1 Top Event OG (the offsite power grid). This top event models the availability of the plant offsite grid, including the station auxiliary transformer. For the loss of offsite power initiating event, this top event acts as a switch because only the portion of the electric power system on the failure branch is quantified. For the other plant initiating events, this top event models the likelihood of failure of the plant offsite grid after a plant transient event that results in loss of generator output. The value associated with this top event is based on the grid reliability characteristics of the Con Edison system.

3.1.5.2.2 Top Event 5 (6.9-kV Bus 5). This top models the availability of 6.9-kV Bus 5 after a plant trip. For most initiating events, this bus remains powered. (The likelihood of failure is small). If the offsite grid is failed (Top Event OG fails), this top event is not questioned in the electric power event tree. Failure of this top event results in failure of power to 6.9-kV Bus 2, challenges diesel generators associated with Buses 5A and 2A (i.e., diesel generators 21 and 22), and requires that the batteries fed from chargers associated with these buses provide DC power until the diesel generators reload the bus and the operators reload the affected motor control centers.

3.1.5.2.3 Top Event 6 (6.9-kV Bus 6). This top event models the availability of 6.9-kV Bus 6 after a plant trip. For most initiating events, this bus also remains powered. If the offsite grid is failed (Top Event OG fails), this top event is guaranteed failed in the split fraction logic. Failure of this top event results in failure of power to 6.9-kV Bus 3, challenges diesel generators associated with Buses 6A and 3A (diesel generators 23 and 22), and requires that the batteries fed from chargers associated with these buses provide DC power until the diesel generators reload the bus and the operators reload the affected motor control centers.

3.1.5.2.4 Top Event 2 (6.9-kV Bus 2). This top event models the availability of 6.9-kV Bus 2 after a plant trip. This bus is normally supplied from the generator output. After a generator trip, this bus power supply is automatically shifted to 6.9-kV Bus 5. Failure of this bus results in loss of power to 480V Bus 2A, loss of power to the battery charger for DC Bus 22, and automatic start of the diesel generator 22 that supplies 2A. If Top Event OG or Top Event 5 fails, this top event is guaranteed to fail.

3.1.5.2.5 Top Event 3 (6.9-kV Bus 3). This top event models the availability of 6.9-kV Bus 3 after a plant trip. This bus is normally supplied from the generator output. After the generator trip, this bus power supply is automatically shifted to 6.9-kV Bus 6. Failure of this bus results in loss of power to 480V Bus 3A, loss of power to the battery charger for DC Bus 23, and automatic start of the diesel generator 22 that supplies 3A. If Top Event OG or Top Event 6 fails, this top event is guaranteed to fail.

3.1.5.2.6 Top Event D1 (DC Bus 21). This top event models the availability of 125V DC

Battery 21. Failure of this top event results in loss of control power at 6.9-kV Buses 5 and 2, loss of primary control power for Buses 5A and 3A and diesel generator 21, and loss of one channel (A) of safety injection actuation. Loss of control power results in the inability to open or close breakers in the associated AC bus. Normally, this DC bus is supplied by the battery charger fed from Bus 5A through MCC 29. If power is lost to Bus 5A, the battery connected to this DC bus is capable of supplying the required DC loads for a minimum of two hours. Operator action is necessary to reload the battery charger when power is restored to Bus 5A.

3.1.5.2.7 Top Event D2 (DC Bus 22). This top event models the availability of 125V DC Battery 22. Failure of this top event results in loss of control power at 6.9-kV Buses 6 and 3, loss of primary control power for Buses 6A and 2A and diesel generators 22 and 23, and loss of one channel (B) of safety injection actuation. Loss of control power results in the inability to open or close breakers in the associated AC bus. Normally, this DC bus is supplied by the battery charger fed from Bus 2A through MCC 24. If power is lost to Bus 2A, the battery connected to this DC bus is assumed to be capable of supplying the required DC loads for a minimum of three hours. Operator action is necessary to reload the battery charger when power is restored to Bus 2A.

3.1.5.2.8 Top Event D3 (DC Bus 23). This top event models the availability of 125V DC Bus 23. This bus is primarily a backup to DC Buses 21 and 22 and is not questioned if DC Buses 21 and 22 are successful. If either DC Bus 21 or 22 falls, this DC bus is questioned. This bus supplies backup control power to 480V buses 5A and 3A and backup DC control power for diesel generators 21 (Bus 5A supply) and 22 (Buses 2A and 3A supply). The battery charger for this bus is supplied from 480V Bus 3A through MCC 22. Operator action is necessary to restore power to this MCC after power is restored in Bus 3A.

3.1.5.2.9 Top Event D4 (DC Bus 24). This top event models the availability of 125V DC Bus 24. This bus is primarily a backup to DC Bus 22 and is not questioned if DC Bus 22 is successful. If DC Bus 22 fails, this DC bus is questioned. This bus supplies backup control power to 480V Buses 6A and 2A and backup DC control power for diesel generator 23 (Bus 6A supply). The battery charger for this bus is supplied from 480V Bus 6A through MCC 26B. Operator action is not necessary to restore power to this MCC after power is restored to Bus 6A.

3.1.5.2.10 Top Event G1 (diesel generator 21). This top event models the unavailability of diesel generator 21. This diesel supplies emergency power in 480V Bus 5A. With normal supply of power from Bus 5, this diesel is not challenged. With a loss of offsite power or power from Bus 5, this diesel generator must start and reload Bus 5A. Control power to this diesel generator is supplied from DC Buses 21 and 23. The transfer of control power is automatic so that both buses must fail to cause failure of control power to this diesel generator.

3.1.5.2.11 Top Event G2 (diesel generator 22). This top event models the unavailability of diesel generator 22. This diesel supplies emergency power to 480V Buses 2A and 3A. With normal supply of power to these buses, this diesel is not challenged. With a loss of offsite power from Bus 5, Bus 6, Bus 2 or Bus 3, this diesel generator must start and reload Buses 2A and/or 3A. Control power to this diesel generator is supplied from DC Buses 22 and 23. The transfer of control power is automatic so that both buses must fail to cause failure of control power to this diesel generator.

3.1.5.2.12 Top Event G3 (diesel generator 23). This top event models the unavailability of diesel generator 23. This diesel supplies emergency power to 480V Bus 6A. With normal supply of power to Bus 6A, this diesel is not challenged. With a loss of offsite power or power from Bus 6, this diesel generator must start and reload Bus 6A. Control power to this diesel generator is supplied from DC buses 22 and 24. The transfer of control power is automatic so that both buses must fail to cause failure of control power to this diesel generator.

3.1.5.2.13 Top Event 5A (480 Bus 5A). This top event models the availability of 480V Bus 5A. This top event includes vital MCC 26A and other MCCs fed from this bus. Also included is the diesel generator bus feed for sequences that challenge diesel generator 21. With offsite power available and no loss of power at Bus 5, this bus remains energized, and no breaker operations are necessary. If Bus 5 fails or the offsite grid is unavailable, the 5 to 5A feed breaker must open, and diesel generator 21 feed breaker must close after which the diesel starts to restore power to this bus. Control power to this bus is supplied from DC Buses 21 and 23. The transfer of control power is automatic so that both DC buses must fail to cause failure of control power at this bus.

3.1.5.2.14 Top Event 6A (480V Bus 6A). This top event models the availability of 480V Bus 6A. This top event includes vital MCC 26B and other MCCs fed from this bus. Also included is the diesel generator bus feed for sequences that challenge diesel generator 23. With offsite power available and no loss of power at Bus 6, this bus remains energized, and no breaker operations are necessary. If Bus 6 fails or the offsite grid is unavailable, the 6 to 6A feed breaker must open, and diesel generator 23 feed breaker must close after which the diesel starts to restore power to this bus. Control power to this bus is supplied from DC Buses 22 and 24. The transfer of control power is automatic so that both DC buses must fail to cause failure of control power at this bus.

3.1.5.2.15 Top Event 2A (480V Bus 2A). This top event models the availability of 480V Bus 2A. This top event includes the MCCs fed from this bus. Also included is the diesel generator bus feed for sequences that challenge diesel generator 22. With offsite power available and no loss of power at Bus 5 or Bus 2, this bus remains energized, and no breaker operations are necessary. If Bus 5 or Bus 2 fails or the offsite grid is unavailable, the 2 to 2A feed breaker must open, and diesel generator 22 feed breaker must close after which the diesel starts to restore power to this bus. Control power to this bus is supplied from DC Buses 22 and 24. The transfer of control power is automatic so that

DC buses must fail to cause failure or control power at this bus.

3.1.5.2.16 Top Event 3A (480 Bus 3A). This top event models the availability of 480V Bus 3A. This top event includes the MCCs fed from this bus. Also included is the diesel generator bus feed for sequences that challenge diesel generator 22. With offsite power available and no loss of power at Bus 6 or Bus 3, this bus remains energized, and no breaker operations are necessary. If Bus 6 or Bus 3 fails or the offsite grid is unavailable, the 3 to 3A feed breaker must open, and diesel generator 22 feed breaker must close after which the diesel starts to restore power to this bus. Control power to this bus is supplied from DC Buses 21 and 23. The transfer of control power is automatic so that both DC buses must fail to cause failure of control power at this bus.

3.1.5.2.17 Top Event FO (diesel generator fuel oil system). This top event models the diesel generator fuel oil system. This system consists of three fuel oil pumps drawing from three fuel oil storage tanks. The pumps discharge into a common header, and any pump can supply any of the three diesel generators. Pump 21 receives power from Bus 5A, Pump 22 receives power from Bus 2A and Pump 23 receives power from Bus 6A.

Although any one fuel oil pump can supply all three diesels, each pump only receives start signals from two diesels based on fuel oil day tank level. The primary start signal is from the pump's associated diesel generator fuel oil day tank; e.g., Pump 21 from Diesel 21 and day tank, Pump 22 from Diesel 22 day tank, and Pump 23 from Diesel 23 day tank. The backup start signals are fed as follows: Pump 21 from diesel day tank 22, Pump 22 from diesel day tank 23 and Pump 23 from diesel day tank 21.

The number of diesel generators started and the status of power at the various 480V buses all combine to determine the number of fuel oil pumps available to the fuel oil requirements for the diesel generators.

3.1.5.3 Other Support Systems Model

The systems modeled in the "other support systems" model include the Engineered Safety Features Actuation System (ESFAS) (denoted as SAS in this analysis), the essential and nonessential service water headers and the component cooling water system. Figure 3.1-10 is the event tree that represents the other support systems model developed for IP-2. The event tree split fraction logic is shown in Table 3.1-26.

The following sections describe the dependencies and top events used in developing this model.

3.1.5.3.1 Top Event EA (safety injection actuation - Train A). This top event models the availability of safety injection actuation Train A. This function is necessary for the various loss of coolant inventory accidents modeled in the IPPSS. Failure of this top event is assumed to result in loss of the automatic start signal for the affected components. Most equipment at Indian Point 2 that is actuated on safety injection receives signals from both trains of actuation; however, some components, such as motor-operated valves, only receive signals from one train. The original systems analysis for IPPSS identifies these components. This top event is affected by the status of power at DC Bus 21. Loss of this DC bus results in failure of this top event.

3.1.5.3.2 Top Event EB (safety injection actuation - Train B). This top event models the availability of safety injection actuation Train B and is similar to Top Event SA, described previously. This function is affected by the status power at DC Bus 22. Loss of this DC bus results in failure of this top event.

3.1.5.3.3 Top Event SA (essential service water header). This top event models the availability of the service water header that is supplying essential service water services. During normal plant operation, two pumps are normally operating to provide these services. This top event is affected by the status of power at Buses 5A, 6A and 2A (or 3A). Although these pumps may continue to operate following a some transients (ie. no LOSP or SI signal), it has been conservativley assumed that the pumps must start in determining the system reliability. On loss of power to Bus 5A, 6A, 2A or 3A, failure of this top event ensures loss of power to these buses due to loss of diesel generator cooling. Failure of this top event also is assumed to result in immediate failure of the containment fan cooling function.

3.1.5.3.4 Top Event SB (nonessential service water header). This top event models the availability of the service water loop assigned to provide nonessential cooling services, primarily component cooling water heat removal. During normal plant operation, two pumps are operating to provide nonessential cooling water flow. Loss of this service water header is assumed to result in immediate failure of the component cooling water system. This top event is affected by the status of power at Buses 5A, 6A and 2A/3A. As in the case of the essential service water header pump start is conservatively assumed to be required under all circumstances.

3.1.5.3.5 Top Event CC (component cooling system). This top event models the availability of component cooling system. The success criterion for the component cooling system (CCS) is one of three pumps continuing to operate for 24 hours after an initiating event. Normally, two pumps are operating to support plant operation. The third pump is selected to automatically start on low header pressure. As in the case of the the service water system model, pump start is conservatively assumed to be required in all cases.

3.1.6 Sequence Grouping and Back End Interface

3.1.6.1 Plant Damage State Overview

The interface between the Level 1 Systems Analysis and the Level 2 Containment Analysis consists of a set of plant damage state (PDS) groups. The plant damage states (PDS) defines a set of functional characteristics for system operation which are important to accident progression, containment failure and source term definition. Each PDS contains Level 1 sequences with sufficient similarity in system functional characteristics that the containment accident progression for all sequences in the group can be considered to be essentially the same. Each PDS defines a unique set of conditions regarding the state of the plant and containment systems and the physical state of the core, primary coolant system and the containment boundary at the time of core damage/vessel failure. The important functional characteristics for each PDS are determined by the critical parameters (system functions) which impact these key results. The sequence characteristics which are important are defined by the requirements of the containment accident progression analysis. They include, for example, the type of accident initiator, the operability/non-operability of important systems, the value of important state variables (e.g., primary system pressure) which are defined by system operation, and timing of key events.

The Level 2 analysis provides guidance on these important sequence characteristics to the Level 1 analysis in order that the Level 1 sequence event "trees" provide the necessary and sufficient information for the Level 2 analysis. The Level 1 core damage event trees are then extended as part of the Level 1 analysis to contain all the necessary information (system events) to allow all sequences to be unambiguously assigned to specific plant damage states.

The plant damage states contain the system information necessary to evaluate the containment accident progression (evaluate the CET) with the possible exceptions of systems failures which result from the occurrence of specific physical phenomena (e.g. hydrogen burn failing containment sprays) and operator, recovery or mitigation actions which occur subsequent to core damage. Since systems important to the containment analysis are considered in conjunction with systems important to core damage in the Level 1 trees, dependencies between containment systems and all other systems are handled in a consistent manner.

3.1.6.2 Plant Damage State Grouping Criteria

The criteria for each plant damage state include system functional parameters (e.g., containment heat removal availability), important initiating events (e.g., LOCA vs. transient), and important parameters defined by systems operation (e.g., primary system pressure, low or high). Grouping criteria that were considered here for developing separate plant damage states are:

Status of containment isolation
Containment bypass (interfacing system LOCA)
Small LOCA, large LOCA, or transient initiating event
Station Blackout (if transient)
Pressure in RCS at core melt and at vessel failure
Containment spray availability
Sequence Development Times
Containment heat removal availability
Low-pressure injection availawlity
High-pressure injection availability
Auxiliary building release mitigation capabilities
(fire sprays, ventilation, flooding, etc.)
Steam generator tube rupture leakage path
Recovery of systems or functions

Included in "recovery of systems or functions" is recovery of AC power if the sequence is of the SBO type and operator actions that are successful after core damage but before vessel or containment failure.

Injection as used in the list above represents supplying water either in the injection or recirculation mode, depending on the time and the sequence. This may represent the availability of water either into the vessel or later into containment as a mechanism for cooling or fission product removal.

This list is derived from the following sources:

1. NUS Previous Experience, e.g. Surry IPE (Ref. 3.1-10)
2. NRC Guidance in NUREG-1335
3. Other NRC PRA Work, specifically NUREG-4550 (Ref.3.1-11).
4. EPRI Guidance (in draft EPRI RP-3114-29 Report, Ref 3.1-12)
5. IPPSS
6. Other Published PRA Studies

The actual basis for the selection of the criteria for IP-2 is discussed later.

3.1.6.3 IP-2 Plant Damage State Grouping

The logic diagram in Figure 3.1-11 illustrates the selected grouping criteria. The chosen number of plant damage states is that which is sufficient to differentiate important system functional combinations impacting containment challenge. The goal of the grouping process is to develop the minimum number of plant damage states necessary to adequately distinguish the important combinations of systems states which can result in distinctly different accident progression pathways and hence, different containment failure and source term characteristics.

Each pathway through the logic diagram consists of a set of conditions which define a unique plant damage state and for which a unique containment event tree will be developed. The logic diagram also serves as the template for sorting individual Level I sequences into the appropriate plant damage states.

The first two headings of the logic diagram classify the sequence types. Power recovery is only ascertained for the SBO sequence types as discussed above. For every non-bypass class with power available, the status of containment spray operability and containment heat removal availability is questioned. Based on the definition of the various LOCAs, the RCS pressure is assigned either as LO LO for the large LOCAs or LO HI for the small and medium LOCAs. For the other non-bypass classes the possible pressure regimes of LO HI, HIGH and HI HI are used as classifications. In some cases, discussions with the Level I analysts resulted in the suppression of the LO HI branch as being negligible or not possible and, in one case, also the HIGH branch. The status of the in-vessel injection was not used as a classifying item for cases where CHR was not available, as Level 1 analyses showed that injection was not available either, at a high level of correlation, so that injection was considered failed in these cases.

Recovery of in-vessel injection is only important before vessel failure as a classifying item and so this is questioned only for the case where power is recovered in time. Again Level 1 analysis indicated that in fact only a limited number of cases existed where this would be a discriminant. Otherwise injection was assumed failed. For other transients it is possible for the injection pumps to be deadheaded (in miniflow) for both HIGH and HI HI pressure regimes. In the case of the large LOCA injection would either be on or failed. For small and medium LOCAs, the injection would either be failed or in miniflow status in the majority of cases.

No direct credit for Primary Auxiliary Building (PAB) fission product removal is taken in this study. Thus fission product release mitigation in the PAB leakage path is not selected as a PDS criterion. For the SGTR cases, the accident is assumed to proceed such that the secondary side is dry at the time of core melt and so this is not a distinguishing criterion either. The low pressure and high pressure water sources are not differentiated in the Level II analysis and are not therefore are not distinct PDS criteria (although for the sequence timing, it is carried implicitly in the success/failure of the water supply criterion.) The IP-2 containment isolation status is included directly in the containment event tree and is therefore not a separate PDS criterion. Containment isolation is treated as an component containment failure mode event in the CET applicable to every sequence.

The rationale for selection of each of the PDS grouping parameters utilized is discussed below.

3.1.6.3.1 Containment Bypass

This parameter is used to divide the Level 1 sequences into by-pass and non-bypass groups. Furthermore, the containment bypass sequences are subdivided into interfacing system LOCA ("EVENT V") and non-isolated steam generator tube rupture ("SGTR") groups. The containment bypass sequences are distinctly different from non-bypass sequences in that there exists a direct flow pathway from the primary system to outside the containment boundary which permanently bypasses the main containment region. Hence, holdup and attenuation of radionuclides (released from the core/primary system prior to vessel failure) are not affected by the natural processes and engineered safety systems in containment. Consequently, bypass sequences can result in relatively large source term releases early in time. The interfacing system LOCA and SGTR bypass sequences are separated into different groups because the radionuclide release pathways for these two groups of sequences are distinctly different.

For SGTR sequences, the pathway includes the reactor coolant system (RCS), steam generator (SG) secondary side, secondary steam line and safety/relief valves. Two possibilities are recognized (i.e. one where the path to the atmosphere is continuously open such as a stuck-open valve, and one where the relief valves continue to operate normally). In the latter case, the valves cycle, the pressure is relieved intermittently, and, very importantly, the valve closes when the reactor vessel fails and the pressure drops to the containment ambient. These circumstances lead to a significantly smaller source term compared to the SORV case.

For the most significant interfacing system LOCA sequences, the pathway is RCS, low pressure injection (LPI) system piping and the RHR suction piping in the PAB.
Sequences are initially classified into four groups, according to the integrity of the containment at core damage. The event tree headings which impact this characteristic are as follows:

Event Tree Heading Description	Symbol
Interfacing Systems LOCA Initiating Event	VSEQ
Isolate Ruptured SG - Early	OS
Isolate Ruptured SG - Late	SO
Operator Cooldown and Depressurize (without Auxiliary Feedwater)	O3

Sequences are characterized into each of the four groups using the following logic:

Bypass Characteristic Branch	Grouping Logic
Event V	INIT = VSEQ
SGTR with Stuck Open Valve	(INIT = SGTR)*(OS=F * SO=B + SO=F+ O3=F)
SGTR with Cycling Valve	OS=S * SO=B + SO=S
No Bypass	none of the above

The event V and SGTR sequences are not characterized further.

3.1.6.3.2 Transient or LOCA Type

This parameter is used to separate transient sequences from LOCA sequences and to further subdivide large LOCA sequences from the small/medium LOCAs. The major reasons for the use of this parameter for grouping are: 1) to aid in the subsequent classification of sequences by RCS pressure, 2) to distinguish sequences with distinctly different key event timing, and 3) for radionuclide release and transport behavior differences. Small and medium LOCAs have been combined since their containment accident progression is expected to be similar.

The non bypass LOCAs and transient sequences are classified according to initiator type as defined by the following headings:

Event Tree Heading Description	Symbol
Loss of Offsite Power	LOSP
Station Blackout	ST
Recovery of Offsite Power within 30 mins.	P1
Start Gas Turbine within 30 mins.	T1
Large LOCA	LLOCA
Medium LOCA	MLOCA
Small LOCA	SLOCA

Non bypass sequences are characterized using the following logic:

Transient or LOCA Branch	Grouping Logic
Large LOCA	INIT = LLOCA
Small/Medium LOCA	INIT = MLOCA + INIT = SLOCA
Station Blackout	(INIT = LOSP) * P1=F * T1=F
Other transients	none of the above

3.1.6.3.3 Station Blackout

This parameter is used to distinguish transient sequences with total loss of AC power (and failure to recover power prior to core damage initiation) from all other transient sequences. This distinction is not made for LOCA initiated sequences since a LOCA initiated sequence with total loss of AC power has a very low frequency. Station blackout is selected as a grouping parameter for several reasons. First, total loss of AC power results in a sequence without any containment safeguards (sprays or containment heat removal). Second, past studies of IP-2 (IPPSS and Ref.3.1-15) and other plants indicate that station blackout sequences can be important contributors to core damage and offsite risks. Third, power recovery subsequent to core damage allows for the possible restoration of in-vessel injection which may terminate the accident and prevent vessel failure or restoration of containment sprays and containment heat removal in sufficient time to prevent containment failure or mitigate the source term.

3.1.6.3.4 Power Recovery

This parameter is used to identify station blackout sequences with recovery of AC power from offsite or the gas turbines subsequent to core damage but prior to vessel failure and/or containment failure. Three possible branch pathways are evaluated; 1) "PRIOR RV FAILURE", 2)"PRIOR CONTAINMENT FAILURE" and 3) "NO POWER RECOVERY". Power recovery subsequent to core damage allows for 1) the possible restoration of in-vessel injection which may terminate the accident and prevent vessel failure or 2) restoration of containment sprays and containment heat removal in sufficient time to prevent containment failure or mitigate the source term.

For large dry PWR containments, there will be many hours between core damage and the time when the containment integrity is first threatened from long term steam/non-condensible gas pressurization. The IP2 containment failure lower bound capacity (fifth percentile) has been conservatively estimated at 95 psig (see Sec. 4.4) based on assigning the "lower limit" capacity of 126 psig determined in the IPPSS as the median value.

We have used this lower bound failure pressure to assess time available for power recovery prior to containment failure. MAAP calculations for a number of sequences without CHR and sprays indicate the time period of between core damage initiation and the time that the containment pressure reaches the lower bound pressure to be at least 10-15 hours. The IPPSS study indicates at least 12 hours with no containment safeguards.

MAAP calculations for a variety of sequences for IP-2 predict a time interval of from 1 to more than 2 hours between core uncovery and core slump. The MAAP code does not calculate the time between slump and vessel failure using instead an input value. At TMI-2, the head did not fail even though some 15-20 tons of debris coherently poured into the lower head. In the MAAP analyses performed for source term purposes here, a conservatively short time of one minute was used. A somewhat longer period can safely be estimated for timing purposes.

The status of AC power recovery for station blackout sequences is questioned prior to vessel failure and containment failure. The following event tree headings are used to define this characteristic.

Event Tree Heading Description	Symbol
No Vessel Failure Before Power Recovery	VF
No Containment Failure Prior to Power Recovery	CF

Power recovery for station blackout sequences is characterized as follows:

Power Recovery Branch	Grouping Logic
Prior to Vessel Failure	-VF=F
Prior to Containment Failure	CF=S
No Power Recovery	CF=F

3.1.6.3.5 Containment Spray Recirculation

Operation of the containment sprays provide several important functions which impact containment accident progression, containment loading and the radionuclide source term. With or without the containment heat removal function available, operation of the sprays will attenuate fission products released to the containment atmosphere and greatly reduce the source term. The sprays also provide a source of water to debris in the reactor cavity or on the lower containment floor for cooling the debris. Cooling the debris ex-vessel prevents debris concrete attack and the release of radionuclides and non-condensible and combustible gases.

To be considered successful for the purpose of this grouping the sprays must operate during periods of time when fission product release is occurring and when containment heat removal is required. Spray recirculation can be through the RHR system pumps or low pressure recirculation pumps. There must be sufficient water in the sump for this to be successful. Successful operation of only the containment injection spray system does not fully meet the requirements for successful spray operation. Sequences with only containment spray injection system operation may be conservatively grouped into PDS with sequences with no sprays, in part depending on the Level 1 quantification results.

All non bypass and non SGTR sequences are classified according to whether containment sprays (event tree heading CS) are operating or not.

Containment Spray Branch	Grouping Logic
YES	CS=S
NO	-CS=S

3.1.6.3.5 Containment Heat Removal

Operation of sufficient containment heat removal (i.e. operation of the RHR in recirculation, and containment sprays in the case of the large LOCA, or the fan coolers with functional heat exchangers) is necessary to prevent long term containment overpressure failure from steam generation and high containment temperature. Successful operation of containment heat removal requires that heat removal be established prior to the containment reaching a pressure where containment integrity is first threatened (taken to be 95 psig). This requirement generally affects SBO sequences where success of AC power recovery (prior to containment failure) is based on the time period from onset of core damage to the time when the containment integrity is initially threatened.

All non bypass SGTR sequences are classified according to whether containment heat removal is available or not. The following event tree headings are used to define this characteristic:

Event Tree Heading Description	Symbol
Fan Coolers	FC
Containment Sprays	CS
Recirculation Cooling	RH
RWST	RW
Accumulators	AS
Low Pressure Injection	LP or LI
High Pressure Injection	HP

The Fan Coolers and the RHR heat exchangers provide redundant means of containment heat removal. However, in order for the Fan Coolers to remove sufficient heat from the containment atmosphere to maintain containment pressure within acceptable limits, adequate water must be present in the containment. MAAP calculations show that the water inventory of the RCS and the Accumulators is adequate and injection from the RWST is not required. The following logic defines the containment heat removal characteristic.

Containment Heat Removal Branch	Grouping Logic
YES (given Success of CS)	FC=S + RH=S
YES (given Failure or Bypass of CS)	FC=S * (LP=S + -AS=F) +RH=S
NO (given Success of CS)	FC=F * -RH=S
NO (given Failure or Bypass of CS	FC=F * -RH=S + (RW=F + -LP=S + -HP=S + -LI=S) * AS=F

3.1.6.3.6 RCS Pressure During Core Damage/At Vessel Failure

The reactor coolant system pressure during core damage and at the time of vessel failure can have a major impact on several potentially important containment events. High RCS pressures during core heatup and core damage facilitate natural circulation heat transfer from the core to the hot leg which increases the potential for high temperature induced hot leg, surge line or steam generator tube failure. Although the subject of considerable uncertainty, elevated pressures at the time of vessel rupture may result in entrainment of the core debris out of the reactor cavity and increase the potential for debris fragmentation and dispersal into the main containment gas volume thus increasing the potential for direct containment heating (DCH). Four pressure regimes have been identified as being significant. These are:

Pressure Regime	Pressure Range (psia)
LO LO	< 200
LO HI	200 - 2000
HIGH	2000 - 2350
HI HI	> 2350

The reasons for this selection of pressure regimes for use as PDS characteristics is discussed below. Energetic dispersal of the debris out of the reactor cavity following vessel failure is not expected for RCS pressures below about 200 psi, whereas for RCS pressures above 200 psi, there is a belief by some that debris entrainment and dispersal out of the cavity and DCH are potentially important processes. The 200 psi value was the threshold pressure for these phenomena in NUREG/CR-4551 (Ref. 3.1-15). The 2000 psi value was judged by the NUREG-1150 In-Vessel Expert Panel as the lowest pressure where induced hot leg or surge line creep rupture failure was credible (though unlikely). At very high RCS pressures in the range of the pressurizer relief/safety value setpoints (> 2350 psia) the NUREG-1150 experts panel judged that induced hot leg or surge line failure was likely and that induced steam generator tube rupture was possible (at a rather low probability level).

The following event tree headings were used to define the pressure regime characteristic:

Event Tree/Heading Description	Symbol
LOCA Beyond ECCS Capacity	ELOCA
Large LOCA	LLOCA
Medium LOCA	MLOCA
Small LOCA	SLOCA
PORV Bleed	O1
Stuck Open PORV	PV
Block Valve Close	BV
Consequential SGTR	TR
Turbine Trip	TT

Pressure Relief	PR
Secure from Pressure Relief	SR
Auxiliary Feedwater	L1

The logic used to define the damage state with respect to pressure is as follows:

Event Tree Branch	Grouping Logic	Pressure Regime	Notes
ELOCA,LLOCA	all	LO	
MLOCA,SLOCA	all	LO HI	
LOSP	O1=S + ST=F * LI=S * -SG=F + L1=S * (LS=F + PV=F * -BV=S)	LO HI	(1)
	PV=F * -BV=S	HI	(2)
	none of the above LOSP conditions	HI HI	
GT	O1=S + L1=S * (PV=F + LS=F + TR=F)	LO HI	(1)
	PV=F + TR=F	HI	(3)
	None of the above GT conditions	HI HI	
ATWS	PR=F + SR=F + TT=F	HI	(4)
	None of the above ATWS Conditions	HI HI	

Notes: (1) Any core damage sequence in the General Transient or LOSP event trees in which AFW is successful must include some kind of consequential LOCA. (Otherwise the accident would have been successfully mitigated). The inclusion of the consequential LOCA mechanism is therefore redundant and can be deleted

(2) With no AFS, a stuck open PORV or consequential SGTR are assumed to maintain the RCS pressure below the 2335 psia (PORV set point). However an RCP seal LOCA may not be large enough.

(3) For PDS 26 and 27 it is assumed that an RCP seal LOCA alone will reduce the CS pressure to high. This is inconsistent with the discussion under note 2 but does not significantly impact the results due to the relatively high frequency of PDS 24 compared with PDS 26 and 27.

(4) ATWS core damage sequences involving failure of adequate pressure relief, failure to secure pressure relief or failure of turbine trip are assumed to lead to a LOCA which depressurizes the RCS below the 2350 psia.

3.1.6.3.7 Status of In-vessel Injection

The status of in-vessel injection at the time of core damage is important for several reasons. If in-vessel injection is available during the period of core damage, core damage may be limited and vessel failure prevented. This situation would be the case for a large break LOCA sequence with operable LPI but with failure of the accumulator function. For this sequence the Level 1 success criteria indicate core damage occurs. It is reasonable to expect that core damage will occur, however also reasonable to expect that continuing damage could be arrested prior to inducing failure, such as was the experience at TMI-2. If the RCS pressure is elevated above the LPI injection threshold pressure (approximately 350 ft head) but the system is available (on miniflow) it could provide in-vessel injection if the RCS is depressurized prior to RV failure (such as by an induced hot-leg rupture). The in-vessel injection systems may also be available following off-site power recovery for station blackout sequences (this type of recovery being the only ones credited in the Level II analyses.) The four possible branches for this heading are thus:

ON	(available and operating)
DEADHEAD	(available but cannot inject because of high RCS pressure)
RECOVERED	(injection recovered subsequent to core damage but prior to the anticipated time of RV failure)
FAILED	(never available)

The event tree headings which impact this characteristic are as follows:

Event Tree/Heading Description	Symbol
High Head Recirculation	HR
Low Head Recirculation	LR

The following logic is used to define the damage state with respect to In-Vessel Injection.

In Vessel Injection Branch	Grouping Logic
Recovered/Dead Headed	HR=S + LR=S
Failed	-(HR=S + LR=S)

Note: In order to limit the number of unique plant damage states to a manageable number, the Status of In-Vessel injection is not questioned (and presumed to be unavailable or irrelevant) under the following conditions and for the following reasons:

- Due to shared components, it is probable that, when Containment Sprays or Containment Heat Removal are unavailable, in vessel injection is also failed.

- When the RCS pressure is LO HI, the likelihood of induced hot leg rupture following core damage is very small (assumed to be 0 in CETs). Since RCS depressurization will not occur prior to vessel failure, the status of in vessel injection is irrelevant.

- When there is no power revovery prior to vessel failure.

3.1.6.4 PDS Logic Diagram and PDS Characteristics

The initial PDS grouping logic diagram developed for IP-2 is shown in Figure 3.1-11. It has 54 end points (plant damage states). The numerical results are shown in the extreme left hand column. Based on the frequencies and characteristics of the end states, this diagram was condensed to the final 31 plant damage state diagram as follows. All states with frequencies less than 10^{-8} were assigned to another state judged sufficiently similar. The "receiving" always had a sufficiently higher frequency that the augmentations did not significantly perturb them. The following assignments were made:

PDS 2 and PDS 7 to PDS 1
PDS 6 to PDS 5
PDS 11 to PDS 10
PDS 18 to PDS 14
PDS 22 to PDS 21
PDS 25 and PDS 27 to PDS 29
PDS 39 to PDS 38
PDS 45 and PDS 48 to PDS 51
PDS 49 to PDS 50

Then any states with zero residual frequency were eliminated from the logic diagram.

3.1.7 References

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3.1-2 WCAP-11993, "Joint Westinghouse Owners Group/Westinghouse Program: Assessment of Compliance with ATWS Rule Basis For Westinghouse PWRs", December 1988.

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3.1-4 Con Edison Internal Correspondence (NAF-2-036) dated June 4, 1992, "Indian Point Unit No. 2 Embrittlement Parameters"

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3.1-12 Z. T. Mendoza, "Generic Framework For Individual Plant Examination (IPE) Backend (Level 2) Analysis",Main Report (EPRI-RP-3114-29), 1991 (Draft).

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3.1-18 WCAP-9691, "NUREG-0578 2.1.9.C Transient and Accident Analysis", March, 1980.

3.1-19 WCAP-9601, "Report on Small Break Accidents For Westinghouse NSSS Systems", June, 1979.

3.1-20 WCAP-9754, "Inadequate Core Cooling Studies of Scenarios With Feedwater Available, Using The NOTRUMP Computer Code", June, 1980.

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SECTION 3.2

SYSTEMS ANALYSIS

3.2 Systems Analysis

3.2.1 General Methodology

In the Indian Point Unit No. 2 plant level model, the event tree top events represent the systemic or functional failures required to allow the initiating event to proceed to a core damage state. The system configuration selected for each top event is dependent on both the initiating event and the support system failures, if any, which exist at the time that the system is challenged. These system configurations are represented by "split fractions" which are quantified through use of algebraic system equations. These equations are derived using boolean logic based on the system models developed in the original IPPSS, and updated as appropriate.

The system equations are arranged such that the contributions to each split fraction (i.e. hardware, maintenance, operator error, common cause) can be easily derived. The individual contributions and the total split fraction values are provided in system cause tables.

The following sections describe the systems modelled in the Indian Point Unit No.2 IPE and the top events and split fractions associated with those systems. Due to the need for some systems to work together to achieve a mitigating function and conversely, for separate systems to be able to independently achieve success of the function, not all systems modelled correspond to standard plant system definitions. The system equations and cause tables for each split fraction are also provided. Since this IPE builds upon the extensive work performed in the original IPPSS modelling, the IPPSS system logic diagrams are not reproduced here. Table 3.2-1 provides a list of the systems or functions addressed in support of the IPE plant model along with a cross reference to the applicable section in the IPPSS (for those systems previously addressed in the IPPSS) and the IP2 UFSAR. IP2 UFSAR drawings for the systems modelled in the IPE are provided in Figures 3.2-1 through 3.2-16. All system models reflect the system configuration in place at the conclusion of the 1991 refueling outage.

Dependencies between front line systems and support systems, and where applicable, between support systems and other support systems, are described in Section 3.1.5.1. System success criteria is dependent in most cases on the specific event tree model in which the system is challenged. A specific discussion of success criteria has therefore been included as a section (Section 3.1.2) in the Accident Sequence Delineation portion of this report.

3.2.2 Accumulator System (ACS)

3.2.2.1 Purpose

The Accumulator System (ACS) is essentially a passive injection system which delivers borated water to the cold legs of the RCS when the RCS pressure drops below 66O psig. For those primary system break sizes in which the RCS depressurizes quickly, the accumulators serve to reflood and cool the core in the time interval before the active injection systems become effective. Success is defined as the injection of three accumulators into the three intact legs, given that a LOCA has occurred on the fourth leg.

3.2.2.2 System Description

For a large LOCA, the accumulator tanks discharge to provide sufficient water to the reactor coolant system to initiate reflood of the core before the low pressure injection system starts to provide flow. Unlike the high and low pressure injection systems which require pumps for injection, the accumulator tanks are passive components, and injection occurs when the RCS pressure drops below the pressure of the nitrogen blanket in the tanks. Each reactor coolant cold leg pipe is served by an accumulator, and all the tanks are of identical design.

Redundant level sensors provide accumulator tank level indication in the central control room. Redundant low and high level alarms annunciate in the control room when the tank level varies from the normal operating level by more than a preset value.

When the reactor coolant system pressure falls below the accumulator pressure, the discharge from each accumulator passes through a motor-operated isolation valve, which is de-energized open during plant operation. These valves also receive a confirmatory signal to open upon safeguards actuation. Flow then passes through two check valves and into the cold leg piping of the RCS.

Accumulators are maintained at a nominal pressure of 660 psig which is monitored by redundant pressure sensors that provide a control room display of the pressure. Redundant high and low pressure alarms annunciate if the pressure varies from the normal pressure by more than a preset value.

3.2.2.3 Technical Specifications

The technical specifications governing the accumulators are listed under the Engineering Safety Features, Section 3.3.A.1.c:

- o The four accumulators are pressurized to at least 615 psig and each contain a minimum of 787.5 ft^3 and a maximum of 802.5 ft^3 of water with a boron concentration of at least 2000 ppm. None of the accumulators may be isolated.

3.2.2.4 Top Events

Since the accumulators are essentially passive devices, there are no boundary conditions associated with this system and the only top event considered within ACS is AS which represents the Accumulator System under all analyzed conditions.

3.2.2.5 Split Fractions

The definitions for the ACS split fractions associated with the system top event are provided in Table 3.2-2a. The results of the system level split fraction quantification are provided in Table 3.2-2b. The system equation file is provided in Table 3.2-2c. Although a guaranteed failure split fraction (ACF) is included for completeness and consistency, the Accumulator System model does not actually include any support system dependencies and this split fraction is, therefore, not required to be used in this analysis.

3.2.3 Auxiliary Feedwater System (AFS)

3.2.3.1 Purpose

The auxiliary feedwater system (AFS) provides secondary side heat removal through the steam generators during normal plant shutdown and heatup as well as during plant transients.

3.2.3.2 System Description

The AFS supplies water to each of the four steam generators whenever the main feedwater system is unavailable. The AFS must operate during small break loss of coolant accidents and during transients that involve or result in loss of main feedwater. The system is also used during normal plant startup and shutdown activities.

The AFS utilizes two motor driven pumps and one steam turbine driven pump. The two motor-driven pumps can provide sufficient flow to meet system requirements and are arranged so that each pump supplies two steam generators. 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. The steam driven pump alone can provide sufficient flow to meet system requirements and can supply all four steam generators. The steam for this pump is supplied from the main steam lines leading from Steam Generators 22 and 23 upstream of the main steam isolation valves.

Redundant water supplies are available to the AFS. The primary source is a gravity feed from the Condensate Storage Tank (CST), which has a total capacity of 600,000 gallons. Availability of water from this source is guaranteed by LCV-1158, which terminates flow to conventional plant functions should the quantity of water in the tank drop to 360,000 gallons (This is the quantity of water required to remove the residual heat generated by the reactor for at least 24 hours at hot shutdown conditions). Redundant level indicators and control room alarms are provided for the condensate storage tank.

The backup supply to the auxiliary feedwater pumps is the City Water Storage Tank which has a 1.5 million gallon capacity and is shared with Indian Point Unit No. 3. Each pump is supplied from a header through a check valve and a normally closed control valve.

Each of the auxiliary feedwater pump discharge lines has an air-operated flow control valve which is 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.

Level in the steam generators is controlled manually from the control room during AFS operation by positioning the flow control valves. Air to these valves is from the Instrument Air System with automatic backup by a nitrogen (bottle) system.

In addition to remote control from the control room, all the AFS pumps and regulating valves can be operated locally from within the auxiliary feedwater building.

Power to auxiliary feedwater pumps 21 and 23 is supplied from 480V vital buses 3A and 6A, respectively. The following conditions will automatically start the motor-driven pumps:

- o Loss of either of the two main feedwater pumps.
- o Low-low level in any one of four steam generators.
- o Unit trip together with loss of offsite power and no safety injection signal. This will provide both pumps with a start signal after the Emergency Diesel Generators are connected to the 480V buses.

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.

Undervoltage on either bus 3A or 6A will trip the pump fed by that bus.

Turbine-Driven Auxiliary Feedwater Pump Subsystem

The turbine-driven pump is a horizontal, multistage, centrifugal pump with a capacity of 800 gpm at 1,350 psi. As mentioned above, steam is supplied to the turbine from the main steam system upstream of the main steam isolation valves. Two temperature control valves, PCV-1310A and PCV-1310B, are mounted in series in the steam supply line to the turbine-driven pump. These valves protect the motor-driven pumps in the unlikely event that the portion of this steam supply line located 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. Low pressure to the AFS Turbine will alarm in the central control room. Normally, PCV-1139 is maintained in automatic standby with air pressure applied to the valve actuator holding the valve closed. The solenoid valves will be automatically de-energized and the turbine-driven pump started by either of the following:

1. Low-low 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).

3.2.3.3 Technical Specifications

With the RCS temperature above 350 degrees F:

- with one or more auxiliary feedwater pump inoperable the pump should be restored to operable status within 72 hours or cool the RCS to below 350 degrees F.
- with two AFW pumps inoperable, cool the RCS below 350 degrees F within 12 hours.
- with three AFW pumps inoperable, immediately initiate corrective action to restore one AFW pump to operable status while maintaining power at existing level until at least one AFW pump has been restored to operable status.

3.2.3.4 Top Events

There is one top event (L1) in the AFS system model which addresses the AFW functions under all boundary conditions. This top event covers AFW response under normal transient conditions, when called upon to achieve rapid primary system depressurization, and in response to an anticipated transient without scram (ATWS).

3.2.3.5 Split Fractions

The definition of each Auxiliary Feedwater System split fraction associated with the system top event is provided in Table 3.2-3a. The results of the system level split fraction quantification are provided in Table 3.2-3b. The system equation file is provided in Table 3.2-3c.

3.2.4 Component Cooling Water System (CCS)

3.2.4.1 Purpose

The purpose of the Component Cooling Water System (CCW), following an initiating event, is to provide heat removal from the recirculated primary coolant following injection and to provide cooling for post accident operation of vital equipment. The CCW System also provides heat removal for various components and systems during normal plant operation.

3.2.4.2 System Description

The Component Cooling Water System (CCW) is a closed loop system consisting of three pumps, two heat exchangers which are cooled by the service water system, a single surge tank, and the necessary piping and valves to supply the various cooled equipment. During normal plant operation, either one or two of the three pumps, and one heat CCW exchanger, are required to supply the necessary cooling. During accident conditions, one of the three pumps and one heat exchanger is required during the recirculation phase to act as an intermediate heat sink for removing decay heat from the core and the containment and to cool vital equipment. Low pump discharge pressure is annunciated in the central control room and will automatically start an additional pump, if available. This analysis conservatively assumes running pumps are required to restart under all transient conditions.

The CCW surge tank, which is located in the primary auxiliary building (PAB), accommodates changes in fluid volume of CCW due to system thermal transients. Surge tank level is indicated and alarmed in the control room.

The two CCW heat exchangers are shell and tube type heat exchangers which are cooled by the service water system. During normal plant operation, both heat exchangers have CCW passing through, however only one heat exchanger is normally lined up with Service Water. This heat exchanger lineup is not required to be changed for accident mitigation. The heat exchanger outlet temperature and header return temperature are monitored and alarmed in the control room.

The primary CCW loads following an accident are the residual heat removal (RHR) heat exchangers, RHR pumps, safety injection (SI) pumps, charging pumps (CP) and as a heat sink for the auxiliary component cooling pumps for Recirculation Pump cooling.

Each of the three safety injection pumps drives an attached circulating pump which supplies the cooling requirements for the safety injection pump bearings using the water contained in the CCW supply and return headers. The CCW leaving the three safety injection pumps combine into a single return line. The flow through this line is monitored and alarmed in the control room. The two RHR pumps are also cooled by CCW during operation. The cooling water flow for these pumps is indicated locally and alarmed in the control room.

The CCW System does not operate during the injection phase of an accident following a loss of offsite power. As a result, two motor driven Auxiliary Component Cooling Pumps are provided to supply component cooling water to the Recirculation Pump motors, during the injection phase, to protect them from the containment atmosphere.

3.2.4.3 Technical Specifications:

1) The reactor shall not be made critical unless the following conditions are met:

- o Three component cooling pumps together with their associated piping and valves are operable.
- o Two component cooling heat exchangers together with their associated piping and valves are operable.

During power operation, the requirements of the above may be modified to allow one of the following components to be inoperable at any one time. If the system is not restored to meet the conditions of the above within the time period specified, the reactor shall be placed in hot shutdown condition utilizing normal operating procedures. If the requirements of the above are not satisfied within an additional 48 hours, the reactor shall be placed in the cold shutdown condition utilizing normal operating procedures.

- o One of the three operable component cooling water pumps may be out of service provided the pump is restored to operable status within 14 days.
- o An additional component cooling water pump may be out of service provided a second pump is restored to operable status within 24 hours.
- o One component cooling water heat exchanger or other passive component may be out of service for a period not to exceed 48 hours provided the system may still operate at design accident capabilities.

3.2.4.4 Top Events

There are two top events in the component cooling water analysis which address:

CC the initial response of the system given the various possible electric power states

CO the response of the system following recovery of offsite power (from grid or Gas Turbines) given a LOSP and an initial failure of CCW resulting from some combination of CCW components and/or emergency power sources. This top event accounts for the initial failures included in CC.

3.2.4.5 Split Fractions

The definition of each CCW split fraction associated with the system top events is provided in Table 3.2-4a. The results of the system level split fraction quantification are provided in Table 3.2-4b. The system equation file is provided in Table 3.2-4c.

3.2.5 Containment Spray System (CSS)

3.2.5.1 Purpose

The purpose of the Containment Spray System (CSS) is to provide pressure reduction and radionuclide removal from the Containment atmosphere following a LOCA or a steam break accident inside containment. The Containment Spray System and the Fan Cooler Units which are described in Section 3.2.7 provide the overall containment cooling and filtration function. The systems augment each other although each is capable of fulfilling the pressure reducing function independently.

3.2.5.2 System Description

The containment spray system provides borated water, initially drawn from the refueling water storage tank (RWST) to two sets of the containment spray rings located in the containment dome. The RWST is addressed separately in the HPIS analysis in Section 3.2.8. During injection, the containment spray function is provided by two 3000 gpm Containment Spray Pumps. The flow from each pump passes through two parallel motor operated discharge valves, a check valve and a motor operated containment isolation valve before entering Containment. Each header then flows directly to two of four separate spray nozzle ring header. During the recirculation phase, spray is provided to the ring headers by the Recirculation Pumps or the Residual Heat Removal (RHR) Pumps with heat removal provided by the RHR Heat Exchangers. This function is addressed in the Recirculation analysis (Section 3.2.13). The Containment Spray System also includes a Spray Additive (Sodium Hydroxide) Tank on the suction line to the Spray Pumps. The spray additive provides radionuclide scrubbing enhancement and is drawn from the tank by eduction.

The Containment Spray System is a standby system and has no active function during normal plant operation or shutdown.

The valves on the pump suction lines from the RWST are maintained in the locked open position. Each Containment Spray Pump has two motor-operated discharge valves in parallel which are normally closed. The parallel discharge valve flow paths assure flow in the event either valve should fail to open on demand. The discharge header containment isolation valves are locked open.

Following a safety injection signal the containment spray system is brought into service by either of the following signals:

- o High-High Containment Pressure.

- o Manual Initiation.

If a spray signal is initiated by high-high containment pressure, the following will occur:

- o The spray pump discharge valves are supplied with an open signal.

- o Both spray pumps will be signaled to start.

For each manual push button depressed, a single pump train will start.

Since the switchover from the injection to the recirulation phase is initiated with approximately 80,000 gallons remaining in the RWST, the Containment Spray Pumps continue to supply water to the spray headers until the remaining RWST inventory is exhausted.

3.2.5.3 Technical Specifications

One containment spray pump may be inoperable during power operation, for a period not to exceed 72 hours, providing the five fan cooler units and the remaining containment spray pump are operable.

3.2.5.4 Top Events

The top events considered within CSS address the Containment Spray System during the injection phase and the Containment spray actuation function. The Containment Spray recirculation function is addressed in the Recirculation System analysis (Section 3.2.13). These top events are:

CS Containment Spray Function
CA Containment Spray Actuation

3.2.5.5 Split Fractions

The definition of each CSS split fraction associated with the system top events is provided in Table 3.2-5a. The results of the system level split fraction quantification are provided in Table 3.2-5b. The system equation file is provided in Table 3.2-5c.

3.2.6 Electric Power System (EPS)

3.2.6.1 Purpose

The primary functions of the electric power system are to:

- o 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.

- o Provide a reliable source of control power for the operation of these systems and for the initiation of safeguards systems actuation signals.

- o 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.

3.2.6.2 System Description

The Indian Point Unit #2 electric power system provides a source of motive, control, and instrumentation power to 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 that all offsite power sources are lost. Three diesel generators, each capable of supplying 50% of the power requirements of the safeguards systems components, provide the independent onsite power generation capability. In addition, one onsite gas turbine generator and two gas turbine generators located at the adjacent Buchanan substation may be started and connected to the station electric power system through the offsite power supply tielines.

A DC power system, supplied from four onsite storage batteries, provides backup power to vital controls and instrumentation, and is the primary source of power to all safeguards actuation and reactor protection system circuits.

Since all initiating events (except ATWS) are conservatively assumed to result in a trip of the main generator, power supply to the plant electric power system from the turbine/generator is not credited in this analysis. Manual recovery of power by starting of the Gas Turbine Generators (GT's) and recovery of the normal offsite power source are not included in the EPS model, but are included in the Offsite Power Recovery (OPR) system analysis.

The normal offsite power supply enters Indian Point Unit 2 through a Station Auxiliary Transformer which provide a voltage stepdown from 138kV to 6.9kV and feeds 6.9kV Buses 5 and 6 directly. The 6.9kV system and the remainder of the onsite normal and emergency power systems are further described below.

The electrical power system (EPS) model was developed under two conditions:

1. Offsite power not available.
2. Offsite power available.

Three loss of offsite power (LOSP) conditions are particularly important to the 480V power supply system. These conditions are:

1. Safety Injection With No LOSP: 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 LOSP: defined by a coincident safety injection signal with undervoltage at either bus 5A or 6A, indicating probable loss of offsite power.
3. LOSP With No Safety Injection: defined by undervoltage at bus 5A or 6A, indicating probable loss of offsite power with no coincident SI signal.

Recovery of offsite power is addressed in Section 3.2.16 (OPR analysis). Although included in the original IPPSS, recovery of failed diesel generators was not credited in the IPE update. In addition, only Gas Turbines 1 and 3 had full blackstart capability at the time of this analysis. As a result, power recovery using Gas Turbine Unit 2 was excluded from the offsite power recovery analysis.

3.2.6.2.1 6.9kV System

Six 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. 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. During power operation, 6.9kV 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. Since buses 5 and 6 are normally supplied from the station auxiliary transformer, they are not affected by the operating status of the main generator. 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.

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.

3.2.6.2.2 480V AC Power

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 normal power source is unavailable, an independent source of onsite power is provided to each of these buses from one of the three emergency diesel generator units. Emergency Diesel Generator 21 supplies Bus 5A, Emergency Diesel Generator 22 supplies buses 2A and 3A, and Emergency Diesel Generator 23 supplies bus 6A.

Although the ability exists to crosstie buses 5A and 2A, buses 6A and 3A, and buses 2A and 3A, the crosstie breakers are locked open during power operation and no credit has been taken for these crossties in the IPE model.

3.2.6.2.3 Emergency Diesel Generators

Each of the three emergency diesel generators are capable of supplying sufficient power to maintain the operation of at least 50% of the safequards system components required for mitigating any of the design basis accident scenarios analyzed in the FSAR.

All three diesel generators receive an automatic starting signal under either of the following conditions:

- o Undervoltage on any 480V bus.
- o Safety injection signal.

The diesel generator output breakers will close automatically to load the diesel generators onto their associated 480V buses only under the following conditions:

- o Safety injection with LOSP.
- o LOSP with no safety injection (coincident with a main generator trip).

Cooling for the Emergency Diesel Generators is provided by the essential service water header. Fuel oil is supplied to each EDG by its associated 175 gallon day tank which allows an immediate gravity feed to the EDG and is sufficient to support EDG operation for approximately one hour when filled to 65% capacity. Upon reaching a low level point in the day tank, fuel oil is automatically pumped to the day tank from one of three 7700 gallon fuel oil storage tanks. This capacity is sufficient to support EDG operation for several days without replenishment. Additional fuel oil is available on or near the site.

3.2.6.2.4 125V DC Power

The Indian Point Unit 2 125V DC power system consists of four power panels (21 through 24) each of which receive its normal power supply from a dedicated battery charger powered from one of the 480V buses through a motor control center. Backup power to each power panel is provided by an independent battery which is maintained under continuous charge by the self-regulating battery chargers. Ground detection is provided for each battery division with alarms in the central control room. DC Power Panels 21 and 22 provide the primary sources of DC power to the safeguards equipment in Unit 2 with selected loads (including DC control power for the 480V switchgear and diesel generators) receiving backup DC power from Panels 23 and 24. Each DC Power Panel, through its associated static inverter, also provides the primary source of AC power for the four 118V AC instrument buses. Backup power to these instrument buses is provided through step-down transformers from MCC's which receive power from the 480V buses.

3.2.6.3 Technical Specifications

The following electric power system components must be operable before the unit can be brought above the cold shutdown condition:

- At least two 138 kV transmission lines to the 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 13W93) and 13.8/6.9kV transformer available,
- All four 480V buses energized, with crosstie breakers between buses 5A and 2A and between buses 6A and 3A open,
- All three diesel generators operable,
- A minimum of 19,000 gallons of diesel fuel in the underground storage tanks, with an additional 29,000 gallons of fuel available onsite or from the Buchanan substation,
- Batteries 21, 22, 23, 24, and their associated DC distribution systems and battery chargers operable.

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.

3.2.6.4 Top Events

The top events defined for the electric power system (EPS) address offsite power, the 6.9kV and 480V AC buses the 125V DC buses, the Emergency Diesel Generators and the fuel oil supply to the EDG's:

OG	Availability of power from the off-site grid
W2	Availability of 6.9 kv bus 2
X3	Availability of 6.9 kv bus 3
Y5	Availability of 6.9 kv bus 5
Z6	Availability of 6.9 kv bus 6
D1	Availability of DC bus 21
D2	Availability of DC bus 22
D3	Availability of DC bus 23
D4	Availability of DC bus 24
DG	Availability of Specific EDG Combinations
G1	Availability of EDG 21
G2	Availability of EDG 22
G3	Availability of EDG 23
A2	Availability of 480V AC Bus 2A
A3	Availability of 480V AC Bus 3A
A5	Availability of 480V AC Bus 5A
A6	Availability of 480V AC Bus 6A
FO	Availability of EDG fuel oil system

3.2.6.5 Split Fractions

The definition of each EPS split fraction associated with the system top events are provided in Table 3.2-6a. The results of the system level split fraction quantification are provided in Table 3.2-6b. The system equation files are provided in Table 3.2-6c.

3.2.7 Containment Air Recirculation Cooling and Filtration System (FCU)

3.2.7.1 Purpose

The purpose of the Containment Air Recirculation Cooling and Filtration System (FCU) following an accident is to provide cooling and radionuclide removal of the containment atmosphere. The cooling process also provides pressure reduction to maintain containment integrity. The Fan Cooler Units and the Containment Spray System which is addressed in Section 3.2.5 provide overall containment cooling and filtration function. The systems augment each other although each is capable of fulfilling the pressure reducing function independently.

3.2.7.2 System Description

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. Heat removed by the units is transferred to the ultimate heat sink by the service water system.

The Containment Cooling and Filtration System (FCU) consists of five fan cooler units, each containing a fan unit, roughing filters, cooling coils, demisters, high efficiency particulate filters and charcoal filters. The roughing filters are designed to remove large particles before they reach the high efficiency filters. The containment atmosphere is drawn across finned cooling coils and cooled by service water passing through the coils. During normal operation, the flow through the FCU bypasses the charcoal filter assembly. In case of an accident, a portion of the air flow is directed through the charcoal filter assembly, by the repositioning of butterfly valves, to remove volatile iodine. The remainder of the flow continues to bypass the charcoal filter passing through baffle plates having apressure drop similar to the charcoal filters. All the flow then leaves the FCU and enters a common distribution header.

The FCU fan motors are fitted with heat exchangers that are cooled by service water. Both the fan cooler unit cooling coils and the associated motor cooler receive service water from a common line. The discharge from each motor cooler is separate from that of the main cooling coils and each contains two motor-operated valves (MOVs) in series.

Upon a safeguards actuation signal, 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. 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 Vent Fan Cooling Water Low Flow in the CCR would annunciate.

The FCU model takes no credit for radionuclide reduction by the charcoal filters contained in the Fan Cooler Units. All fans are assumed to require restart following any safeguards actuation signal.

3.2.7.3 Technical Specifications

During normal power operations, one fan cooler unit may be inoperable for a period not to exceed 7 days provided that both containment spray pumps are operable.

3.2.7.4 Top Events

The only top event considered within FCU is FC which represents the Fan Cooler operation under all accident conditions

3.2.7.5 Split Fractions

The definition of each FCU split fraction associated with the system top event is provided in Table 3.2-7a. The results of the system level split fraction quantification are provided in Table 3.2-7b. The system equation files are provided in Table 3.2-7c.

3.2.8 High Pressure Injection System (HPIS)

3.2.8.1 Purpose

The high pressure injection system (HPIS) provides emergency cooling water to the reactor coolant system during events involving loss of primary system inventory when the pressure of the primary system remains high. Such cases include small and some medium break loss of coolant accidents as well as secondary side (steam line) breaks.

3.2.8.2 System Description

The high pressure injection system (HPIS) consists of three safety injection pumps which receive borated water from the Refueling Water Storage Tank (RWST). The RWST contains a minimum of 345,000 gallons of water. The HPIS can supply injection water to the cold legs of all four loops of the primary system when required. The three safety injection pump discharge lines are intertied such that any primary system cold leg can be supplied by two of the three pumps.

Upon receipt of a safety injection signal, all three pumps start automatically. The pump motors receive power from 480V buses 5A, 2A, and 6A (for Safety Injection Pumps 21, 22, and 23, respectively); Pump 22 can also receive backup power from bus 3A. The motor operated valves in this system receive power from MCC 26A or 26B (or from MCC 26AA or 26BB, which are fed from 26A and 26B, respectively).

The motor operated safety injection pump suction valve and discharge valves are normally open and also receive a confirmatory signal to open upon safety injection actuation. If these valves close, the "Safeguards Valves Off Normal Position" alarm in the central control room will annunciate. Flow indication to each loop is also available in the Central Control Room on the safeguards panel.

Safety injection pump cooling is provided by an attached booster pump. Each booster pump is driven by an attached shaft from its respective SI pump and uses the water in the component cooling water supply header for pump cooling.

3.2.8.3 Technical Specifications

- o The RWST must contain at least 345,00 gallons of water with a boron concentration of at least 2000 ppm. The tank low level alarms must be operable.

- o The three safety injection pumps and their associated piping must be operable.

- o The SIS Pump mini flow return valves and valve 1810 in the suction line must be de-energized in the open position. The SIS Pump discharge lines to the RCS cold legs must be open and the discharge lines to the RCS hot legs must be de-energized closed.

- o One SIS pump or one valve required for system operation may be out of service for no more than 24 hours. One RWST alarm may be inoperable for no more than seven days (provided the other alarm is operable).

3.2.8.4 Top Events

The top events considered within HPIS address the RWST, the Safety Injection trains and operator action to accomplish feed and bleed. These top events are:

RW Refueling Water Storage Tank (RWST) availability

HP Ability of the safety injection pumps to deliver required flow to the primary system.

O1 Initiation of primary system bleed using both pressurizer power operated relief valves (PORV's).

O2 Depressurization of primary system to below Safety Injection Pump shutoff head to permit SI boration within 10 minutes following ATWS.

3.2.8.5 Split Fractions

The boundary conditions for each HPIS split fraction associated with the system top events are provided in Table 3.2-8a. The results of the system level split fraction quantification are provided in Table 3.2-8b. The system equation files are provided in Table 3.2-8c.

3.2.9 Low Pressure Injection System (LPIS)

3.2.9.1 Purpose

The Low Pressure Injection System (LPIS) provides emergency cooling water to the Reactor Coolant System during loss of coolant events (LOCA's) involving breaks large enough to substantially depressurize the system. The recirculation cooling function of the system is addressed in a separate system analysis.

3.2.9.2 System Description

The low pressure injection system (LPIS) consists of two low head, high capacity pumps which receive borated water from the RWST. The RWST availability is addressed in the HPIS system analysis. The LPIS pumps also provide the residual heat removal (RHR) function during normal plant shutdowns.

The LPIS pumps draw water from the RWST and discharge it to the primary system through RHR heat exchangers 21 and 22. The heat exchangers do not perform a heat transfer function during active injection, but do serve this function during recirculation. From the outlet of the heat exchangers, injection flow is directed to the four RCS cold legs through lines shared by the discharge of the four accumulators (which are addressed in a separate system analysis).

Upon receipt of an safety injection actuation signal, both pumps start automatically. Pumps 21 and 22 receive power from 480V buses 3A and 6A, respectively. The pump suction and discharge valves are normally open with the power supply to their operators de-energized. If either valve closes, a "Safeguards Valve Off Normal Position" alarm annunciates in the Central Control Room. The outlet valves on the RHR heat exchanger (valves 746 and 747) are normally closed and receive an signal to open upon initiation of a safety injection actuation signal. MOV 746 receives power from bus 5A (via MCC-26A), while MOV 747 receives power from bus 6A (via MCC-26B).

The heat exchanger outlet lines join together into a common header and then branch off to feed the four RCS cold legs downstream of the accumulator outlet line connections. Indication of flow to the four RCS loops is provided in the Central Control Room.

3.2.9.3 Technical Specifications

During normal power operation, the following technical specifications apply to the LPIS system.

- o One residual heat removal pump may be out of service, provided the pump is restored to operable status within 24 hours and the other residual heat removal pump is demonstrated to be operable.

- One residual heat removal heat exchanger may be out of service provided that it is restored to operable service within 48 hours.

- Any valve required for the functioning of the system during and following an accident condition may be inoperable provided that it is restored to operable status within 24 hours and all valves in the system that provide the duplicate function are determined to be operable.

3.2.9.4 Top Events

The top events considered within LPIS address the "normal" low pressure injection system function (LP), and the low pressure injection system function (LI) associated with late injection (after core damage and before vessel failure).

3.2.9.5 Split Fractions

The definition of each LPIS split fraction associated with the system top events is provided in Table 3.2-9a. The results of the system level split fraction quantification are provided in Table 3.2-9b. The system equation files are provided in Table 3.2-9c.

3.2.10 Main Steam System (MSF)

3.2.10.1 Purpose

The primary function of the main steam system (MSF) is to transport the steam produced in the four steam generators to the main turbine generator and provide high and low pressure steam to various balance of plant equipment including the turbine driven auxiliary feedwater pump. During normal plant shutdowns and following transient events, it serves as part of the secondary side cooling function to remove decay heat from the primary system. It also provides a diverse means for rapid depressurization of the primary system, if necessary.

3.2.10.2 System Description

The major components of the main steam system which are relevant to this analysis include four main steam headers, each containing a main steam isolation valve and main steam check valve, five safety valves and an atmospheric relief valve. The system conveys the steam produced in the four steam generators to the the main turbine through turbine control and stop valves. The four steam generators outlet headers are interconnected prior to steam admission to the high pressure turbine so that balanced conditions exist throughout the system. In addition, steam is supplied to the turbine driven auxiliary feedwater pump from a common steam line fed from lines off main steam lines 22 and 23, upstream of the main steam isolation valves.

Each main steam header is protected from overpressurization by five spring loaded safety valves and a power operated atmospheric relief valve. The safety valves are sized to ensure that the secondary system pressure remains within 110% of its design pressure of 1085 psig following a turbine trip with loss of condenser heat sink. Their relief settings are 1065, 1080, 1095, 1100 and 1120 psig respectively.

The power operated atmospheric relief valve (ARV's), located downstream of the safety valves, serve to relieve main steam pressure below the safety valve settings, thereby preventing unnecessary challenges to the safety valves. The ARV's are also used to control primary sytem pressure during normal startups and shutdowns. The valves are automatically conrolled by pressure or may be manually operated from the central control room or from local control stations located near each of the atmospheric relief valves.

Each main steam header contains a swing disk type main steam isolation valve (MSIV). This valve will close automatically upon receipt of a signal from the overall unit protection system and is designed to meet the technical specification requirements to close within five seconds. Downstream of the MSIVs are the reverse flow check valves. The reverse flow check valves are free swinging disk check valves of the same design as the main steam isolation valves. They are installed such that they open in the direction of normal steam flow and are intended to prevent the reverse flow of steam from the other main steam headers in the event of a steam line break upstream of the valve.

3.2.10.3 Technical Specifications

- The main steam stop valves must be capable of closing within five seconds.

- All 20 main steam safety relief valves must be operable, except that up to three may be inoperable under certain very limited, specified conditions.

3.2.10.4 Top Events

The main steam system model includes both the system components and the operator actions required involving the system in response to several initiating events.

The main steam turbine trip (TT) function is demanded in the ATWS event tree. Several MS functions are demanded in the SGTR event tree. These functions include isolation of ruptured SG before or after overfill, RCS cooldown and depressurization with and without auxiliary feedwater. Although not actually part of the main steam system, make up to the RWST following SGTR without successful isolation is included in this system model for modelling efficiency since it is directly related to the other top events included in this system. Following a small or medium LOCA with loss of injection, the main steam system may be used to depressurize the primary sytem to recovery core cooling.ion are In certain loss of power conditions, the MS function may be used to try to depressurize the primary system before vessel failure.

The top events considered within the MSF system are as follows:

Top Event:	Description
TT	Turbine Trip function - (ATWS)
OS	Isolation of Ruptured SG, Early - (SGTR)
O3	RCS Cooldown Depressurization with no AFS - (SGTR)
O4	System Depressurization with AFS - (SGTR)
O5	RCS Cooldown Depressurization - Late - (SGTR)
SO	Stuck Open Safety Valve - (SGTR)
Y1	Core Cooling Recovery - (SLOCA, MLOCA)
SG	Steam Generator Level Control - (LOSP)
DP	Depressurize RCS before vessel failure (LOSP)
MU	RWST Make-up following SGTR (SGTR)

3.2.10.5 Split Fractions

The definition of each MSF split fraction associated with the system top events are provided in Table 3.2-10a. The results of the system level split fraction quantification are provided in Table 3.2-10b. The system equation files are provided in Table 3.2-10c.

3.2.11 Reactor Coolant System (RCS)

3.2.11.1 Purpose

The purpose of the reactor coolant system (RCS) is to remove the heat generated in the reactor core due to the fissioning process and transport this heat to the steam generators for the primary to secondary heat exchange process. The RCS mitigating safety functions addressed in this system model involve integrity and pressure relief capability

3.2.11.2 System Description

The major components of the reactor coolant system include the reactor vessel which contains the core, four cooling loops, each containing a U-tube type steam generator and a vertical reactor coolant pump and a pressurizer which allows precise control of primary system pressure conditions.

The coolant enters the reactor vessel through four inlet nozzles and flows down through the annular space between the core barrel and the reactor vessel outer wall. It then enters a plenum at the bottom of the reactor vessel where it reverses direction and flows upward through the core, removing heat generated in the fuel elements. The coolant leaves the vessel via four outlet nozzles, flows through the RCS "hot legs" and enters the steam generators. In the steam generators, the high pressure, high temperature primary fluid flows through U-tubes, transferring heat to the secondary side fluid and turning it to steam for power production. After passing through the steam generators, the reactor coolant passes through an intermediate leg and enters the suction of the RCS Pumps which return it through the "cold leg" to the reactor vessel.

The Reactor Coolant Pumps are each served by a three stage seal system which is protected from the high temperature reactor coolant by two systems. Charging Pumps provide fluid to the seals, a portion of which enters the RCS through the seals, preventing reverse flow of RCS fluid through the seals. In addition, the Component Cooling System provides cool water to the seals providing the ability to cool any reverse leakage, should it occur, sufficiently to protect the seal integrity. Although the charging are themselves cooled by the CCW System, the charging pumps have some limited ability to operate without cooling and have hard piped backup cooling, which must be manually lined up, from the City Water System. Should all seal protection fail, the RCP Seals are assumed to degrade and eventually result in sufficient loss of primary coolant to require emergency coolant injection.

The RCS is protected from overpressurization by two power operated relief valves (PORV's) and three safety relief valves, all of which are located on the pressurizer. The PORVs respond automatically to system pressure changes, to prevent unnecessary challenges to the safety relief valves. Each of the lines containing a PORV also contains a block valve to allow isolation should a PORV leak or fail to reclose. Although the PORV's can be used in the bleed and feed cooling mode, this function is addressed in the HPIS system analysis.

3.2.11.3 Technical Specifications

Technical specifications require that whenever the RCS is above 350° F, the PROVs and their associated block valves be operable with the block valves either open or closed. If a PORV becomes inoperable, its block valve must be closed and if a block valve becomes inoperable, it must be closed and de-energized. If compliasnce with the above cannot be met within 4 hours, the plant must be in hot shut down within the next 6 hours.

3.2.11.4 Top Events

The top events described in the RCS analysis file address RCP seal failure, PORV operation, and the potential for an induced tube rupture following a main steam line break inside containment. The top events are:

LS - RCP seal failure after loss of CCW.

PV - PORV sticks open, isolated

BV - PORV block valves closed (LOSP)

PR - ATWS pressure relief function

SR - Secure from ATWS pressure relief

PL - Plant power level - ATWS

TR - SGTR given MSLBIC

3.2.11.5 Split Fractions

The definition of each RCS split fraction associated with the system top events is provided in Table 3.2-11a. The results of the system level split fraction quantification are provided in Table 3.2-11b. The system equations are provided in Table 3.2-11c.

3.2.12 Reactor Protection System (RPS)

3.2.12.1 Purpose

The purpose of the Reactor Protection System (RPS) is to detect plant transients which cause plant conditions to exceed specified limits and supply sufficient negative reactivity to the core to shut down the fission process, thereby protecting the core, during those transients.

The RPS protects:
- the reactor core against fuel rod cladding damage caused by departure from nucleate boiling or high power density;
- the reactor coolant system against damage caused by high primary system pressure or sudden loss of its secondary side heat sink

In conjunction with engineered safety systems, the RPS carries out the necessary actions to mitigate the consequences of postulated accidents.

3.2.12.2 System Description

During normal operation, the control rods are fully withdrawn from the reactor core and held in place by stationary gripper coils which are energized from 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. Power is supplied to the rod control panel from the rod drive motor generator sets through normally closed reactor trip breakers (RTA and RTB). Upon opening of the trip breakers or other 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.

Trip bypass breakers (BYA and BYB) are provided to allow testing of the associated 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, closing the other bypass breaker causes both bypass breakers to trip.

The reactor trip breakers are operated by 125 VDC from separate DC sources. To close a reactor trip breaker or bypass breaker, DC power must be available and the undervoltage coil must be energized. The RPS utilizes trip signals from various process sensors to deenergize undervoltage devices and thereby open the two series connected reactor trip breakers. With power removed from the magnetic coils, the rod control cluster assemblies fall by gravity into the active fuel region of the reactor core.

Upon loss of offsite power, the control rod drive motor generator sets lose power. Under this condition, only the physical release and insertion of the control rods must occur to complete the trip action.

When a plant condition setpoint is reached, a signal is sent to the trip bistable for that loop. The bistable deenergizes the associated scram logic relays in the reactor protection logic racks. In addition to the instrument loop bistable, the loop instrumentation also provides indication, alarm, and interlock functions.

There are two trains of actuation logic. Each reactor trip bistable drives two relays, one in each actuation logic train. The logic trains are duplicates of each other and are physically separated. The logic trains are energized from separate 125V DC buses. Loss of power from a 125V DC bus deenergizes the undervoltage trip device in the reactor trip breaker, causing the reactor trip breaker to open.

The reactor trip system as analyzed, includes not only the automatic reactor protection system (RPS) and the control rods, but also manual trip actions in response to a failure of the automatic systems to operate. Operator actions are directed by the Emergency Operating Procedures and include initiating a manual trip signal, deenergizing the motor generator sets by interrupting power to them and manually tripping the motor generator set supply breakers. In this analysis, the initial manual trip is analyzed together with the automatic trip function and must be performed within one minute. Subsequent operator actions to deenergize the MG Sets and emergency borate must be completed within 10 minutes.

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.

3.2.12.3 Technical Specifications

Technical specifications address instrument settings, minimum operable channels and minimum degree of redundancy for each monitored function. The reactor trip logic must have a minimum of one degree of redundancy at all times. The technical specifications did not allow bypass testing during the period represented by this analysis.

3.2.12.4 Top Events

The top events considered within RPS address automatic or manual trip of the reactor within specified times. These top events are:

RT Tripping of the reactor automatically or by operator action within 1 minute after the actuation signal

BR Emergency boration by the operators within 10 minutes given failure of the immediate (automatic or manual) reactor trip function

MD Operator actions to trip the reactor (including those in RT) within a 10 minute time window.

3.2.12.5 Split Fractions

The definition of each RPS split fraction associated with the system top events is provided in Table 3.2-12a. The results of the system level split fraction quantification are provided in Table 3.2-12b. The system equations are provided in Table 3.2-12c.

3.2.13 Recirculation System (RSS)

3.2.13.1 Purpose

The Recirculation System (RSS) provides continued cooling to both the Reactor Coolant System and the containment atmosphere following completion of emergency coolant injection (and depletion of the Refueling Water Storage Tank inventory). The system will provide long term cooling following any size primary system break. The system also provides the capability to supply coolant to one of the RCS hot legs approximately 24 hours after the accident to control boron concentration in the reactor vessel

3.2.13.2 System Description

The recirculation function requires 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 the containment spray nozzles. Although separate systems, since they work together to accomplish the recirculation function, they are modelled in this mode as a single "recirculation system".

The recirculation function is manually initiated by the operators when the water level in the refueling water storage tank (RWST) is at the "low level" alarm point. A specific switching sequence is performed by the control room operators in accordance with emergency operating procedures to realign the systems from the injection to the recirculation mode.

The Safety Injection Pumps which provide high pressure emergency core coolant injection can also provide high pressure recirculation. Recirculation Pumps located inside the Containment Building are the primary means of providing low pressure recirculation. Should this equipment be unable to perform this function, however, backup low pressure recirculation is available using the RHR Pumps, which also provide the low pressure injection function. The low pressure recirculation pumps (either set) are required to function together with the Safety Injection Pumps to allow successful high pressure recirculation. 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 located around the 46 foot elevation of the containment building 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. The pump motors are cooled by auxiliary component cooling pumps (booster pumps) or normal component cooling. The booster pumps are started on a safety injection actuation signal to protect the motors from possible damage caused by containment atmospheric conditions in the early phases of a large break LOCA. The Recirculation Pumps draw suction from the Recirculation Sump which is located below the 46' elevation inside containment. Should the Recirculation Pumps fail to operate, the RHR Pumps can draw water from the Containment Sump, which is also located below the 46' elevation in containment but is separate from the Recirulation Sump.

The discharge of both the Recirculation Pumps and RHR Pumps pass through the RHR heat exchangers which cool the water before it is returned to the core and/or spray header. One RHR heat exchanger can supply both adequate core cooling and containment spray. Component Cooling Water provides cooling for the RHR heat exchangers and is cooled in turn by the Service Water System which is drawn from the ultimate heat sink (Hudson River). The component cooling outlet valves for each heat exchanger are provided a signal to open upon safety injection actuation. 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.

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 from the RHR heat exchangers is directed to the suction of the Safety Injection Pumps to allow high head recirculation.

If high head injection is needed and the line from the outlet of the RHR heat exchangers to the suction of the Safety Injection Pumps is closed or failed, then the RHR pump flow can be realigned to bypass that line and provide a direct suction to the Safety Injection Pumps. The RHR heat exchangers are bypassed under this condition and containment spray recirculation is not possible. Therefore, this mode of recirculation will be successful only if the containment fan coolers are available to remove the heat generated in the core. This capability is not taken credit for in the PRA model.

Although the required post LOCA recirculation path is to the RCS cold legs, hot leg recirculation may be needed to preclude long term (>24 hours) boron precipation concerns. The isolation valves to the hot legs are normally closed and deenergized.

This system analysis also addresses the use of the RHR system in a shutdown cooling recirculation mode, drawing suction from the RCS hot leg. This function is modelled after successful cooldown and depressurization of the primary system following a steam generator tube rupture event.

3.2.13.3 Technical Specifications

Except for the sumps, the Recirculation Pumps and the normal shutdown cooling path to the RHR Pumps, the equipment required for recirculation are part of other systems and are governed by the technical specifications associated with those systems (i.e. low pressure injection system, high pressure injection system and containment spray).

The following technical specifications apply to the Recirculation Pumps, the Containment and Recirculation Sump and the normal shutdown RHR suction path:

One RHR heat exchanger may be out of service provided it is resolved within 48 hours. Any valve may be out of service providing it is restored within 24 hours and all valves in the systems that provide duplicate functions are operable. Both recirculation pumps must be operable during power operation.

3.2.13.4 Top Events

The top events considered within RSS address high head recirculation, low head recirculation (including shutdown cooling where appropriate), the heat removal portions of those two functions and the additional requirements associated with hot leg recirculation. These top events are:

HR High Head Recirculation using the Safety Injection Pumps.

LR Low head recirculation using the Recirculation or RHR pumps. This top event also addresses shutdown cooling.

RH Recirculation heat removal provided by the RHR Heat Exchangers.

RC Additional system requirements for hot leg recirculation.

3.2.13.5 Split Fractions

The definition of each split fraction associated with the RSS top events are provided in Table 3.2-13a. The results of the system level split fraction quantification are provided in Table 3.2-13b. The system equations are provided in Table 3.2-13c.

3.2.14 Safeguards Actuation System (SAS)

3.2.14.1 Purpose

The purpose of the safeguards actuation system (SAS) is to respond to various plant conditions and to initiate actuation signals to the appropriate engineered safeguards equipment as required for mitigation of loss of coolant accidents (LOCAs) and other plant transients.

3.2.14.2 System Description

The SAS receives signals from various primary and secondary plant sensors, processes this input through logic matrices, and sends actuation signals to enginnered safeguards 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).

There are two channels of actuation logic in the SAS. Each logic channel contains six master relay-slave relay sets. These relay sets are:

o 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 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. With the exception of the high-high containment pressure relays, the logic relays are deenergized when an unsafe condition is detected.

Each actuation channel receives DC power from a separate DC power panel. DC power for each channel is monitored by two undervoltage relays which indicate on the front of the associated safeguards logic panel.

The portions of the SAS which are relevant to the core damage model are those required to initiate core cooling injection and containment spray. Although mentioned here, containment spray actuation is treated separately, within the containment spray system analysis. The SAS systems analysis includes consideration of both the actuation logic and the instrumentation providing input signals.

The input signals provided and the resulting safeguard equipment actuation 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). Two of the four steam lines must indicate high steam flow in conjunction with either a low Tavg signal (two of four sensors); or low steam line pressure (two of four sensors). This signal initiates steam line isolation (closure of all four MSIVs) and automatic safety injection.

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 a pre-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 of that for which the pressurizer heaters and charging pump makeup can compensate

results in a decrease in pressurizer pressure, and consequently RCS pressure. An automatic safety injection signal is generated if any two of the three pressurizer pressure channels indicate low pressure.

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. An automatic safety injection signal is generated when containment pressure exceeds the setpoint value in two of the three channels.

5. High-High Containment Pressure
When containment pressure exceeds the high-high setpoint in two out of three channels, containment spray is actuated, a main steam line isolation signal is sent to close the MSIVs and an automatic safety injection signal is developed.

6. Manual Initiation Signals
Safety injection or containment spray may be manually initiated by the operators in the central control room.

3.2.14.3 Technical Specifications

Technical specifications address instrument settings, minimum operable channels and minimum degree of redundancy for each monitored function. The instrument channels must have a minimum of one degree of redundancy at all times. The technical specifications did not allow bypass testing during the period represented by this analysis.

3.2.14.4 Top Events

The top events considered within SAS address the actuation of each train of the safeguards Actuation System. These top events are:

EA Safeguards Actuation System - Train A

EB Safeguards Actuation System - Train B

3.2.14.5 Split Fractions

The definition of each SAS split fraction associated with the system top events is provided in Table 3.2-14a. The results of the system level split fraction quantification are provided in Table 3.2-14b. The system equations are provided in Table 3.2-14c.

3.2.15 Service Water System (SWS)

3.2.15.1 Purpose

The Service Water System (SWS) acts as a heat transport medium, removing heat from components in both the primary any secondary portions of the plant and transferring this heat to the Hudson River. The system provides this cooling function both directly and through the intermediate Component Cooling Water (CCW) System. In conjunction with CCW, this system removes reactor decay heat removal during the recirculation phase following an event requiring core cooling injection.

3.2.15.2 System Description

The SWS consists of two sets of three vertical, centrifugal pumps all of which take suction from the ultimate heat sink (Hudson River) through a series of screens in the intake structure. The discharge of each pump passes through a rotary type strainer. Downstream of the strainers, each set of three pumps ties together into a common header. The two service water headers, referred to as the essential and non-essential headers, can be connected but are normally isolated from each other by two closed valves. No recovery by cross connection of the headers has been included in the model.

The major components supplied by the essential service water header are the five containment fan cooling units and the three emergency diesel generators. Although both the fan cooler and the emergency diesel generator service water lines contain flow control valves, any safety injection signal will result in a creating a full open service water path for both the FCUs and the EDGs.

The major components supplied by the nonessential service water header are the two component cooling system heat exchangers and several balance of plant loads. The CCW heat exchangers are not required until the recirculation phase of an event requiring core cooling injection, at which time they require flow from at least one of the three non-essential SWS pumps. Some of the balance of plant loads served by the nonessential header may also be served from an alternate source in the retired Indian Point Unit No. 1 facility. The use of this Unit 1 equipment is not included in the modelling of this system.

Either set of service water pumps can be configured to serve the essential header, with the other set then providing flow to the nonessential header. Operator action is required, however, to manually realign the system to change header service.

During normal operation, the number of Service Water pumps required to supply each header will vary. Typically, however, two pumps will be operating on each header. The model conservatively assumes that all pumps, including those that where running prior to the initiating event, are subjected to a restart challenge.

In the original model system model there was no inclusion of maintenance unavailability for SWS pumps on the essential header. The current model accounts for maintenance consistent with technical specification limits. Simultaneous maintenance on two pumps is prohibited by technical specifications.

3.2.15.3 Technical Specifications

All three SWS pumps and their associated piping or valves on the essential header must be operable when the RCS temperature is above 350 °F. If one of these SWS pumps becomes inoperable it must be restored within 12 hours or the plant must be in hot shutdown within 6 hours and subsequently cooled below 350 °F using normal operating procedures.

Two of the three SWS pumps and their associated piping or valves on the non-essential header must be operable when the RCS temperature is above 350 °F. If one of these two pumps becomes inoperable it must be restored within 24 hours or the plant must be in hot shutdown within 6 hours and subsequently cooled below 350 °F using normal operating procedures.

Isolation shall be maintained between the essential and non-essential headers at all times when the reactor is above 350 °F except for periods of up to 8 hours for safety related activities.

3.2.15.4 Top Events

The top events considered within SWS address the essential and non-essential service water header response for both SI and non-SI initiating events. They also address the potential for recovery of service water following a LOSP and restoration of an offsite power source. These top events are:

SA Essential header operation following SI - two of three pumps required to operate for 24 hours

SC Essential header operstion following non-SI - one of three pumps required to operate for 24 hours

SB Nonessential header operation under all conditions - one of three pumps required to operate for 24 hours

SE Recovery of the Essential Service Water System, given a LOSP event

SN Recovery of the Non-essential Service Water System, given a LOSP event

3.2.15.5 Split Fractions

The definition of each SWS split fraction associated with the system top events is provided in Table 3.2-15a. The results of the system level split fraction quantification are provided in Table 3.2-15b. The system equations are provided in Table 3.2-15c.

3.2.16 Offsite Power Recovery (OPR)

3.2.16.1 Purpose

Offsite power recovery is not a system, per se, but rather models the likelihood that power can be recovered in sufficient time to prevent further progression of the accident.

3.2.16.2 System Description

Following a loss of offsite power incident, the emergency onsite power system (i.e. the Emergency Diesel Generators and the Emergency DC Power system) provide the necessary power requirements until the normal source of offsite power is restored. In the unlikely event that the Emergency Diesel Generators fail to operate, The restoration of an offsite power source is vital to accident mitigation. This "OPR system" is actually a time dependent model of the combined equipment and operator action required to restore an offsite power source. This recovery of offsite power may involve restoration of the grid or the provision of power from two of the three gas turbines associated with the site. Although there are three installed gas turbines, this analysis only takes credit for Gas Turbines 1 and 3 since Gas Turbine 2 had blackstart limitations at the time of this analysis. The AC power recovery model does not take credit for any operator action to restore a failed Emergency Diesel Generator.

The operator actions which are represented by this system analysis are described in Section 3.3.3 of this report.

3.2.16.3 Technical Specifications

The only Technical Specifications applicable to this model are associated with the gas turbines. At least one Gas Turbine (GT-1, GT-2, GT-3) and associated switchgear must be operable at all times with a minimum of 54,200 gallons of fuel oil available. If this condition is not met within 7 days, an alternate independent system must be provided or cold shutdown initiated within the following 48 hours.

3.2.16.4 Top Events

The top events considered within OPR address the status of AC power recovery from a gas turbine or the grid at various key times following a loss of all AC power. These top events are:

P1 Offsite Power Recovery (OSP) from thr grid

T1 Gas Turbine (GT) Starts and Loads
within 0 <= t <= 1/2 hr.

T2 Gas Turbine (GT) Starts and Loads
within 1/2 <= t <= 1 hr.

T3 Gas Turbine (GT) Starts and Loads
within 1/2 <= t <= 3 hr.

C1 OSP recovery before Core Uncovery

C2 GT Start/Load before Core Uncovery

VF OSP recovery between Core Uncovery, or S/G Dryout & Core Slump
(No additional time is assumed between core slump and vessel failure)

CF No OSP,between Core Slump & Containment Failure

3.2.16.5 Split Fractions

The definition of each OPR split fraction associated with the system top events is provided in Table 3.2-16a. The results of the system level split fraction quantification are provided in Table 3.2-16b. The system equations are provided in Table 3.2-16c.

3.2.17 Emergency Diesel Generator Building Ventilation (VENT)

3.2.17.1 Purpose

The purpose of the Emergency Diesel Generator Building ventilation system (VENT) is to provide adequate heat removal from the EDG building to ensure a proper operating environment for the diesel generators and the controls and instrumentation required to operate them.

3.2.17.2 System Description

The EDG building ventilation system consists of five, wall mounted exhaust fans (318 thru 322), pneumatically controlled exhaust dampers and intake louvers, manual intake louvers and electric space heaters. Power for the fans is supplied through the EDG HVAC Distribution Center located in the EDG building. Power to the distribution center is fed from MCC26A and MCC26C which receive their supplies from 480V buses 5A and 3A respectively.and contains fan starters and a transfer switch. Power to the individual fans are supplied as follows:

- Fans 318, 319 and 321 are fed from MCC 26A
- Fans 320 and 322 are fed from MCC 26C

Fan 318 will transfer automatically to MCC 26C if power from MCC 26A is lost.

The fans and their exhaust dampers are thermostatically controlled as are the four pneumatic intake louvers. Individual initiation temperature set points are as follows:

Fan	Set Point
318	> 80 deg F
321	> 85 deg F
319	> 90 deg F
322	> 95 deg F
320	> 120 deg F

The four pneumatically controlled EDG building inlet louvers also open on a signal from the 80 deg F temperature sensor or when Fan 318 starts in combination with any one of the three diesels operating.

The number of fans required during diesel generator operation depends on the number of EDG's operating and on the outside temperature. Any one fan provides sufficient cooling to support operation of a diesel generator under all but the most severe ambient temperature conditions. Operation of two diesels requires operation of up to three fans, although the third fan is only required at the upper range of ambient temperatures. The same is true during operation of all three diesels.

Modelling Assumptions:

The following assumptions were made while modelling the EDG building ventilation system.

1. The time available following EDG start, to detect the failure of ventilation and take action before unacceptable temperatures are reached is assumed to be insufficient to recover ventilation and is therefore not credited in the model.

2. The fan units are not normally running unless the EDG building air temperature is greater than their associated set point. Although the monthly diesel generator test procedure requires verification that sufficient fans are operating to maintain the building temperature below 100°F, this test may, but does not necessarily verify operation of more than one fan. There is no other specific periodic test of the fans during plant operation.

Consequently, it is assumed that the fans are tested only during plant shut downs, approximately every 18 months. Although a review of maintenance data did not reveal any maintenance downtime for these fans, the limited running time and demands may impact the significance of any conclusions drawn from this data. In order to account for less frequent testing of the IP2 EDG building ventilation fans, and offset any impact on the statistical significance of the absence of maintenance unavailability, a conservative multiplier of 18/3 = 6 has been applied to the probability of fan failure on demand (which is derived from generic industry experience for safety related equipment which is assumed to be tested, on average, every three months).

3. Common cause events for the fan units to start and run are included.

4. The four pneumatically controlled EDG building inlet louvers and the fan outlet dampers, fail open on loss of dc power or instrument air. Thus no support system failures associated with these components are modeled.

5. All combinations of ambient temperatures and associated cooling requirements were included in the system modelling.

3.2.17.3 Technical Specifications:

There are no Limiting Conditions of Operation specifically associated with the EDG building ventilation system.

3.2.17.4 Top Events

The EDG Ventilation System model requires only one top event (ST) which represents the response of the EDG building ventilation given various electric power states.

3.2.17.5 Split Fractions

Split fraction equations were developed for all realistically possible boundary conditions (combinations of diesel operating status and EDG Building Ventilation support state condition) following loss of offsite power. The definition of each VENT split fraction associated with the system top events is provided in Table 3.2-17a. The results of the system level split fraction quantification are provided in Table 3.2-17b. The system equations are provided in Table 3.2-17c.

SECTION 3.3

SEQUENCE QUANTIFICATION

3.3 Sequence Quantification

This section presents the Indian Point Unit No. 2 plant specific database developed during this Individual Plant Examination. All parameters are represented by full uncertainty distributions developed by combining information from industry experience (generic data) with plant specific data collected through a detailed review of plant records.

3.3.1 Generic Data

The integration of plant specific and generic data ensures that all available and relevant information regarding the performance of the components and systems of interest is used in the analysis, and that meaningful and realistic estimates are developed. In those few instances when the amount of available plant specific data was insufficient to allow a meaningful update of generic data, the generic distribution was used directly. Such cases are indicated by asterisk in Table 3.3-2.

3.3.1.1 Sources of Generic Information

The generic information used in the original IPPSS is discussed in Section 1.5.1.2 of that analysis. For the 1989 update and this IPE effort, the source of generic data was a comprehensive database developed by PLG, Inc. (Ref. 3.3-1), specifically for risk and reliability analysis of nuclear power plants. It was developed based on a wide spectrum of generic information on component and system performance and incorporates more than 180 reactor-years of plant specific data collected during the performance of nuclear plant probabilistic risk assessments. The information provided in this generic database has also benefited from the more modern mathematical and computer methods developed since the original IPPSS was performed.

3.3.2 Data Analysis

The goal of our IPE data analysis was to construct a plant specific database that would provide an accurate basis for deriving meaningful results from sequence quantification and allow for detailed interpretation of the results of that quantification.

In order to accomplish this goal, it was necessary to develop a database that accurately reflected the failure modes described in the IPE systems analysis and properly accounted for the Indian Point plant specific component and system performance data since completion of the original IPPSS. The IPE data analysis utilized the techniques described in Section 1.5 of the Indian Point Probabilistic Safety Study (IPPSS) as the primary method of data development and incorporation.

The data analysis described in this section does not include human error rates or common cause failure modes. Those data topics are discussed separately in Sections 3.3.3 and 3.3.4 of this report.

3.3.2.1 Data Analysis Methodology:

The first step in developing a database for use in the IPE was to review the original IPPSS database. The IPPSS database was re-examined by both the systems and data analysts to determine if the component types and failure modes represented by the original basic events were still appropriate based on the updated systems analysis. Where the basic events were determined to still be applicable, they were maintained. Where basic events no longer applied to the component types or failure modes of the updated systems models, they were deleted from the IPE database. Changes and additions made to the systems analyses also required new basic events to be developed and quantified. The complete database was then updated against available plant specific data.

All basic events are represented by a log-normal distribution and have been quantified under uncertainty. Where basic events are represented by point estimate values, the point estimate shown is the mean value of the quantified log-normal distribution. All distributions are presented in terms of their mean, 5th, 50th (median) and 95th percentile values.

As mentioned previously, the Bayesian methodology described in Section 1.5 of the IPPSS was the primary method of data analysis in updating the IPE basic event distributions. In updating the basic events which were maintained from the IPPSS, the previously developed IPPSS distributions were used as the IPE prior distributions. These prior distributions were then updated against plant specific information producing a updated or "posterior" distribution. In quantifying basic events that were redefined or newly developed for the IPE, industry failure experience contained in PLG generic database was used as the prior distribution and then updated with the Indian Point 2 plant specific data collected since the IPPSS. The results of this Bayesian updating process are the final distributions used in the IPE.

Data was collected in the following four groups:

- Test and maintenance frequencies and durations
- Initiating events frequencies
- Component success data
- Component failure rates

3.3.2.2 Test and Maintenance Data

Test and maintenance data was collected, screened and analyzed to determine the unavailability of equipment as a result of test and maintenance activities.

The unavailability of a component as a result of testing refers to those times during which a component is unavailable to perform its intended safety function as a result of the component being taken out of service, or declared inoperable, in order to perform a periodic test. The unavailability of a component as a result of maintenance refers to those times during which a component is unavailable to perform its intended safety function as a result of a maintenance (either scheduled or unscheduled) activity.

In order to assure the accuracy of the component test information used, all revisions of the periodic test procedures for each component, since the performance of the original analysis, were examined. Information obtained based on this review included not only the components directly tested by the procedure, but also any components whose functioning was challenged or verified as a indirect result of the activities performed during the test (e.g. verification of flow through a valve during a pump flow test). For each component challenged by the test, the type and extent of challenge (i.e. number of demands or operating time) provided by each test was also recorded.

Many sources of information were considered for use in the maintenance data analysis task. Documentation of maintenance activities has improved significantly at Indian Point Unit No. 2 since the original IPPSS. Nevertheless, since our data collection covered maintenance activities over an extended time period to ensure that the information obtained accurately reflected Indian Point experience, the best source of unavailability data was determined to be the actual work permits (WP) issued by the Operations Planning group at the time that equipment is taken out of service. All maintenance activities performed on components defined within the systems models during periods of power operation were included in determining component maintenance unavailability.

Although it represented the most manpower intensive method of obtaining maintenance unavailability information, the review of work permits was chosen since they represent a complete, consistent and retrievable record. Since they are numbered consecutively, the completeness of the data was easily verified. In addition, they are subject to a periodic inhouse quality assurance review for completeness and accuracy.

Information available from each work permit (and collected for use in the IPE database) includes:

- The Work Permit number
- The system containing the component
- The specific component identification (tag) number
- The time and date the component was removed from service
- The time and date the component was restored to service

Typically, a single work permit is issued against a component when a maintenance activity is performed. Occasionally, however, multiple work permits are issued against one component. When this occurs, the equipment has overlapping time periods of recorded unavailability due to maintenance. To account for such instances, a sorting of the data was performed, and overlapping maintenance periods were identified. To assure consistent and accurate maintenance durations, when overlapping work permits were identified, the maintenance duration was assumed to last from the issuance of the first work permit to the closeout of the last work permit. Although this may introduce some conservatism, it was not expected to significantly alter the final maintenance unavailabilities.

Overlapping work permits also needed to be identified in order to keep an accurate count of maintenance frequencies. Since maintenance activities performed under multiple work permits within the same outage could alternately have been covered under a single permit and since the full duration of the multiple activities was used, multiple work permits issued concurrently against a single component, were counted as one maintenance activity.

3.3.2.3 Initiating Event Frequencies

Initiating event frequencies were established in several ways depending on the specific type of event.

For plant transients leading to a reactor or turbine trip, plant specific data was collected to establish the yearly rate of such transients. Data regarding plant trips was available from Performance group records. In order to determine the cause of such trips, however, further investigation was required. The primary sources for this additional information were Licensee Event Reports (LER) and investigative trip reports which are equired to be developed by station procedure for each event which results in a plant trip. For Loss of Offsite Power events, plant specific information was also available from Significant Occurrence Reports (SOR's). For all the above initiating events, the generic database information was then updated with this plant specific information using the Bayesian methodology.

For initiating events for which no plant specific data was available (e.g. Loss of Coolant Accidents, Steam Generator Tube Ruptures, etc.), the generic database information was updated by the additional years of Indian Point 2 operating experience without such incidents, again using the Bayesian methodology.

For the Loss of Service Water, Loss of Component Cooling Water, Loss of DC Bus and Loss of 6.9 KV Bus initiating events, plant specific models were developed and used to quantify the expected frequency of each event.

Initiating events which inherently account for plant mode (i.e. those which are only possible during plant power operation) were used directly. Initiating events whose frequencies were calculated on the basis of data which is independent of plant specific operating mode were adjusted to appropriately account for availability. The initiating events which fall into this category are the Loss of Offsite Power event and those represented by plant specific models, as described above.

3.3.2.4 Component Success Data

Success data refers to the demonstrated ability of a component to perform a required function. Success can be measured in terms of the number of times that a component responded to a demand to operate (e.g. successful pump starts, successful valve position transfer) or the number of hours that a component maintained its required operating condition (e.g. successful pump running hours).

Success data was obtained from many sources. Success data was collected during the analysis of periodic test results. Test results include detailed information on both the duration of component operation during the test and the number of demands placed on the component during the test. Success data was also derived from the operators' daily log sheets. The daily control room and Field Operator log sheets and turnover sheets were excellent sources of information on component demands and status and were used wherever possible. Where independent sources were available for the same components, they were used to verify and supplement the primary source.

With regard to run time data, periodic test information was used as a primary source. In addition, for frequently operated components, it was assumed that the operating configuration of a component at the end of each 12 hour period represented the configuration of that component during that full preceding 12 hour period (e.g. a pump that was running at the end of a 12 hour shift was assumed to have been running for that entire shift and a pump that was not running at the end of a shift was considered not to have run for any part of that period). Although this was a necessary simplifying assumption, it is not expected to significantly impact the results and is consistent with the manner in which data was collected and evaluated in the IPPSS. Such information was correlated with test information to assure that run times were not double-counted.

3.3.2.5 Component Failure Rates

The major sources of component failure information were periodic performance tests (PT), Significant Occurrence Reports (SOR), daily surveillance reports (DSR) and turnover sheets (TOS), the corporate maintenance tracking system (PPMIS) and the Central Control Room and Nuclear Plant Operator log books. The Significant Occurrence Reports (SOR's) were found to be the most reliable source of data and were therefore, used as the primary source of information. SOR's are subject to extensive inhouse review and periodic Quality Assurance inspection. As with the success data, where other sources were available for the same failures, they were used to supplement the primary source. To the extent that those other sources were independent, they were also used to verify the information.

As a result of the more mature plant specific database available at this time we were able to improve the accuracy of our plant specific model, by developing component specific "pump failure to start" values as part of the IPE. The original IPPSS used a combined "pump failure to start" value that was generically applied to all pumps in the model.

3.3.2.6 Data Analysis Results

The posterior distributions developed during the IPE database update are provided in the following tables:

- o Table 3.3-1 for Initiating Events
- o Table 3.3-2 for Hardware Failures
- o Table 3.3-3 for Maintenance Frequencies and Durations,
- o Table 3.3-4 for Test Durations

Each table provides the basic event data designator, a brief description of the basic event, and the mean, 5th, 50th (median) and 95th percentile of the distribution. As mentioned previously, human error analysis and treatment of common cause are addressed in a separate section of this report.

3.3.3 Human Reliability

This section describes the reliability analysis associated with pre and post-accident human interactions (HIs) which are incorporated into the Level I portion of the Indian Point 2 (IP-2) IPE plant model. The principal source of information for the pre-accident HIs, such as errors in restoring proper equipment configuration following tests is the NRC Human Reliability Handbook (Ref. 3.3-2). Qualitative and quantitative data are developed for post-accident operator actions according to the IPE 'Submittal Guidance' (NUREG-1335 Ref. 3.3-3). The overall analysis framework builds on EPRI NP-6560-L, (Ref. 3.3-4). The results of this analysis are used for quantification of the system models which are in turn used to quantify the plant model.

3.3.3.1 Background

The original Indian Point Probabilistic Safety Study (IPPSS) was completed during 1982[4]. The basic method used for analyzing all human interactions in the IPPSS was based on the NRC Human Reliability Handbook (Ref. 3.3-2).

Since the original study, numerous plant modifications have been made to IP-2. Furthermore, the original event-based emergency operating procedures (EOPs) have been replaced by modern, symptom-based EOPs (Ref. 3.3-5) derived from the "Emergency Response Guidelines" developed for the Westinghouse Owners Group (WOG). Numerous advances in human reliability analysis (HRA) methods have been made during the time period since the IPPSS was completed, particularly with regard to modeling post-accident actions. Methods and data are now available for more comprehensive analyses of post-accident operator actions. Both industry and NRC sponsored R&D have promoted a consensus approach to HRA which acknowledges the importance of including a range of human factors issues in the qualitative and quantitative assessment of key operator actions. Such issues are:

- Task analysis which relates to current EOPs
- Cue-response structures that relate to available control room information and operator experience in handling certain transients
- Generic and plant specific data from simulator training
- Cognitive models of human error

Based on insights from a large number of PRA studies, it is recognized that post-accident operator actions are generally more risk important than pre-accident operator actions (test, maintenance, calibration). The consensus approach to HRA is therefore to focus the analysis effort on actions taken by plant operators in response to initiating events.

In the IP-2 IPE, therefore, the post-accident operator actions already addressed in the IPPSS are re-evaluated using today's human reliability techniques and data, accounting for current procedures and training. New operator actions are also added to the front-end plant model to reflect the current reactor safety issues. The pre-accident human reliability analysis is essentially unchanged from the original IPPSS. However, current test and maintenance procedures have been reviewed to ensure the validity of the analysis with respect to the current "as operated" plant and, in some cases, it was determined that additional credit for double independent verification of valve alignments or more frequent checking of status, was warranted.

3.3.3.2 Pre Accident Human Interactions

The pre-accident human interaction analysis evaluates the likelihood of valves or switches being left in the wrong position following test and maintenance activities which take place during plant shutdown or normal plant operation. An analysis framework was adopted in the IPPSS and continued through the IPE which recognizes the specific procedures and practices implemented at Indian Point 2. In applying this framework, the importance of independent double verification of component status following any test or maintenance action which requires component realignment, was recognized.

The basic human error rates were derived from best estimates, and the upper and lower bounds provided in the Human Reliability Handbook for this application are shown in Table 3.3-5.

When two or more tasks are performed, the question of dependence between human errors must be addressed. The NRC Human Reliability Handbook defines five levels of dependence and provides equations for evaluating the conditional probabilty of failure of the Nth action (CP_N) given failure of the (N-1)th action. For example:

For low dependence actions	$CP_N = (1 + 19\ P_{N-1})/20$
For moderate dependence actions	$CP_N = (1 + 6\ P_{N-1})/7$
For high dependence actions	$CP_N = (1 + P_{N-1})/2$
For complete dependence	$CP_N = 1$

The specific pre-accident human interactions included in the IP2 IPE are listed in Table 3.3-6.

3.3.3.3 Post Accident Human Interactions

In NUREG-1335, the NRC addresses human reliability issues in 'Introduction and objectives' (Section 1.2), in the discussion of 'Front-end Submittal'and 'Back-end Submittal', and in Appendix C. The emphasis in NUREG-1335 is on the quantification of post-accident actions. No credit is to be taken for recovery actions in IPE submittal unless such actions are supported by written operating procedures and have been demonstrated to be viable.

The framework for HRA analysis of post-accident HIs is based on the EPRI 'Generalized Event Tree Representation of Post-Accident Actions' (Ref. 3.3-6) which is presented in Figure 3.3-1. There are three parameters used in this quantification: the term p_1 represents the probability of errors of detection which are unrecovered, the term p_2 represents the probability of non-response within the available time window, and the term p_3 represents the probability of failure to correctly execute the approriate step in the procedure. Errors made during the execution of actions called for by procedures are modeled as errors of omission (i.e. an action is performed correctly or not at all).

<u>Failure to Detect Condition (p_1 parameter)</u>

The p_1 parameter is not addressed explicitly. A basic assumption associated with the p_1-factor is that for a plant designed according to current and accepted human factors principles, the contribution from p_1 to HEP_{Total} can be expected to be negligible compared with the other contributors. Since IP2 has undergone a detailed control room design review and implemented numerous human factors improvements, this assumption is valid for IP2.

The method for evaluating the parameters p_2 and p_3 attempt to capture the time dependence of the non response probability. Through the use of the HCR\ORE correlation (see discussion below) the p_2 parameter model is directly time dependent.

The p_3 parameter model includes factors for recovery from an initial implementation failure if sufficient time is available. The following specific time information is used:

- T_w = System time-window is the time between the cue which initiates a given action according to the EOPs and the time at which the action must be complete for success. It is generally determined by generic NSSS vendor analyses (WCAPs), running the MAAP code, or other types of thermal-hydraulic analyses.

- $T_{1/2}$ = Operator median response time. This is the time from the primary cue to response by operator. Typically based on insights from simulator training, discussions with plant staff and information provided in other PRA studies.

- T_a = Task implementation time and refers to time it takes to complete the action and includes the time it takes to reach the control of concern and the time for the equipment to reach its required configuration (e.g. valve stroke time). In the case of operations outside the control room, it accounts for transport time from, say, the central control room to the appropriate location in the plant. Again, this time is based on observations of simulator training scenarios, expert judgement or job performance measurements.

- T_{w-cr} = time available for the cognitive response (detection-diagnosis-decision making); $T_{w-cr} = T_w - T_a$

Failure to Respond within Time Window - HCR/ORE Correlation (p_2 parameter)

As described by NUREG/CR-4835, the Human Cognitive Reliability correlation (HCR) is a normalized time-reliability correlation, the shape of which is determined by the dominant human cognitive process. According to the HCR, the operator responses to a cue can be knowledge-based (K), rule-based (R), or skill-based (S) behavior. In applying the original HCR, the PRA analyst determines the dominant type of cognitive process and the median response time ($T_{1/2}$) by observing simulator exercises or applying judgement. The analyst then combines this with a time-window derived from system success requirements to calculate the non-response probability (the p_2-parameter). The original HCR was presented in 1984 and has been used quite extensively on PRA projects such as those for Caorso, Limerick, Ringhals 2, TVO-I/II, Maanshan, Kuosheng, etc.

During the EPRI-sponsored 'Operator Reliability Experiments' (ORE) program, the HCR was modified, based on data collected from a substantial number of simulator exercises. The results of the data analysis indicated a need to re-evaluate the original hypothesis about K-, R-, or S-based behavior. Based on insights obtained from the EPRI-ORE program, the original HCR correlation was modified to become the HCR/ORE. Instead of a Weibull distribution, a lognormal distribution is used to characterize the operator time-reliability curves. The HCR/ORE has the following form:

$$P(T_{w-cr}) = 1 - \Phi[(\ln(T_{w-cr}/T_{1/2}) - \mu)/\sigma]$$

Where index 'w-cr' stands for 'time-window - cognitive response' and $\Phi()$ is the standard normal cumulative distribution and μ and σ are parameters of the lognormal distribution. As shown by the EPRI-ORE data sets, the mean of the logarithmic normalized times (μ) is usually close to zero. The HCR/ORE as given by EPRI NP-6937 (Ref. 3.3-6) is:

$$P(T_{w-cr}) = 1 - \Phi[(\ln(T_{w-cr}/T_{1/2})/\sigma]$$

This time-reliability correlation is similar to the ones proposed by Fragola and Dougherty (Ref. 3.3-7), Illman et al (Ref. 3.3-8) and others.

The approach chosen for the IP-2 IPE uses expert judgement to estimate σ. Based upon the relatively straightforward adaptation of the Westinghouse Owner's Group ERG's at IP2 and an evaluation of control room layout and conditions, the situation at IP2 was judged to be typical of other plants in the analysts experience. The implementation of this expert judgement approach consists of a decision tree to select a σ-value given a limited task analysis. This approach was first developed for the Borssele PSA (Ref. 3.3-9) and later used in the Surry IPE (Ref. 3.3-10).

A basic assumption of this approach is that following the reactor trip and as the plant and operator response progress one can expect to see larger deviations in response times. This assumption is valid for PWRs with EOPs based on the WOG Emergency Response Guidelines. For such plants the initial response is well defined in the EOPs and extensively trained on the simulators. There is also practical ('real') experience from applying the EOPs for the initial phase following a plant trip.

A small σ-value is indicative of expected consistency in crew responses, whereas a large σ-value is indicative of difficult diagnostics, a need for monitoring specific alarms and meters, etc. In summary, the σ is indicative of how demanding a transient is on the control room operators. The basis for the decision tree end points (see Figure 3.3-2) has been derived from the results of the EPRI-ORE program, insights from practical HRA, and insights from observed simulator training.

The decision tree in Figure 3.3-2 has four headings that address the HI-boundary, procedures, training and stress as applicable to PWRs with EOPs based on the WOG Emergency Response Guidelines. For each heading, the questions are asked and depending on the answers, a σ-value is selected that corresponds to the situation under consideration. If the answer to all questions within a heading is 'yes', then the yes-path of the decision tree is chosen. These questions are listed below:

- <u>Heading No. 1: Separation of Actions That Are Memorized As Opposed to</u>

Procedure Directed

- Is the crew response concerned with immediate actions that are essentially learned actions and could be regarded as skill-based?
- Are the required operator response actions primarily concerned with assessment of need for manual back-up actions to automated functions?

• Heading No. 2: Procedural Guidance
  - Is the procedural guidance simple/explicit enough (e.g., one step, clearly defined)?
  - Are the indications/alarms clear enough to support a decision, as opposed to requiring the operator to infer information from various sources? Are the diagnostics straightforward, without need for consulting SPDS or bringing in additional crew?
• Heading No. 3: Operator Training Issues
  - Is the action highly practiced through regular simulator training, and simple to implement?
  - Is coordination among crew members unimportant in responding to cue?
  - Is no conscious planning required by operator to execute action?
• Heading No. 4: Stress Level in Control Room
  - Are there more than only a few well understood critical alarms/annunciators present?
  - Is the timing of operator response not critical?

Looking at the decision tree end points (Figure 3.3-2), branches 1 through 4 represent relatively simple actions that are backed by memorized procedures (e.g., the immediate steps of E-0 per the WOG Emergency Response Guidelines). For highly practiced actions the crew-to-crew variability in responding to a cue can be expected to be relatively minor; i.e., a small σ-value. As the potential distractions in the control room mount, the σ-value can be expected to become larger. Branches 5 through 12 represent actions of moderate to high complexity. The values given in the decision tree are indicative of the range of values to be expected from a detailed simulator measurements program. There are uncertainties associated with each given value, and for a given situation this uncertainty can be substantial.

Failure to Correctly Implement Procedure (p_3 parameter):

Once the crew has identified and diagnosed an event and decided how to respond to it, the proper implementation of corrective actions will either terminate or delay an accident progression. The parameter p_3 is concerned with the implementation phase and the kinds of human error that can relate to "slips" (ie. either the procedure reader misses a step in the procedure, the Reactor Operator (RO) turns the wrong switch on the bench board, or the Nuclear Plant Operator mis-identifies valve/breaker in the plant).

The probability values for event p_3 are taken from the NRC Handbook (Ref. 3.3-2) and the most commonly used mean value is 1.2×10^{-3} per demand which corresponds to:

1) error of commission associated with operator controls arranged well delineated functional groups (Ref. 3.3-2, Table 20-12, item 3), or

2) error of selection in locally operating valves which are clearly labelled and set apart from valves that are similar (Ref. 3.3-2, Table 20-13, item 1)

In most instances, crews will begin to take action well inside the available time window for response, thus leaving ample time for detecting and recovering from any implementation errors. Recovery factors are placed on the initial p_3 probability values given above according to the following rules which are considered to be reasonable, based on expert judgement.

1) if the median response time of the crew ($T_{1/2}$) is < 1/3 of the time available for cognitive response ($T_{w\text{-}cr}$), apply a recovery factor of 0.3.

2) if the median response time of the crew ($T_{1/2}$) is < 1/5 of the time available for cognitive response ($T_{w\text{-}cr}$), apply a recovery factor of 0.1.

Modeling Human Interaction Dependencies

Each human action identified and evaluated in the system models, was reviewed in the context of the accident sequences to which it would contribute, to determine if there were actions appearing in those sequences which may not be totally independent. A dependence was assumed if two or more actions relied on the same cues, were required to take place in the same or overlapping time windows, and were executed in the same procedure.

For example, operator actions following an SGTR event require isolation of the ruptured generator - early (Event tree heading OS), and RCS cooldown and depressurization -early (Event Tree heading O4). "Early" in this case implies "in time to prevent steam generator overfill". These actions are required sequentially during the first hour after the initiating event, rely on the operator detecting the SGTR event based on a given set of plant parameters (hi steam line rad levels, etc) and are directed in procedure E-3. These actions are modeled as dependent in that if the action to isolate the ruptured steam generator is successful, the cognitive response (p_2) to the tube rupture event is assumed to be successful and only the implementation errors (p_3) contribute to the RCS and depressurization operator action. If the operator fails to isolate the the steam generator early, Event OS fails and Event O4 is bypassed in the event tree structure (ie. the steam genenerator is assumed to overfill). Subsequently, RCS cooldown and depressurization - late (Event tree heading O5) is addressed in the event tree. "Late" at this point implies prior to exhaustion of the RWST supply which will not take place until at least 11 hours after the SGTR event. The operator action considered in this event is potentially dependent on the prior failure of the action in event OS since similar cues and procedures are effective and the time windows for action are overlapping. In order to account for the dependence of action in event O5, the time window for late RCS Cooldown and depressurization is not assumed to begin until 1 hour after the SGTR event. That is, the time window begins after the steam generator has overfilled and additional cues as to the nature the accident have become apparent (ie. two phase flow through SG PORVs and hi hi SG level). Thus, by divorcing the time windows for early and late actions and identifying diverse cues, the operator actions in event OS and O5 can be considered independent.

Other sequences where operator action dependencies were found to be important are those associated with ATWS events which involve operator actions to initiate manual scram, de-energize the MG sets, and initiate emergency boration. In those cases, all actions are required within the 10 minutes following scram and separate time windows and cues could not be defined for each action. Each action is therefore evaluated independently and where actions would be combined (as a product) in the equation files only the lower of the two event probabilities was included (ie. $p(HEP_l \times HEP_h) = p(HEP_l)$ where $p(HEP_l) < p(HEP_h)$).

It is important to note that with the exception of manual scram, manual back up to automatic actions have conservatively not been modeled in the IP2 IPE. This conservatism obviates the need to consider operator action dependence where such recovery action is not credited.

Uncertainty Issues.

The p_2 and p_3 probabilities associated with a given action were summed and an error factor (EF) to express the uncertainty of the HEP was applied. It is assumed that a lognormal distribution is satisfactory and subjective EFs were applied using the following 'rule'.

- For HEP = 1.0E-2 or greater, EF = 5
- For HEP < 1.0E-2, EF = 10

3.3.4 Common Cause Analysis

In the IP2 systems analysis, dependent failures such as common cause failures at the system level are treated either explicitly by identifying the causes of dependent failure and incorporating them into the system or event tree sequence models, or implicitly by using certain parameters to account for their contribution to the unavailability of the systems. Examples of the first category are the sharing of common components and certain types of human error during test and maintenance. The second category deals with design errors, construction errors, procedural errors and unforeseen environmental variations.

The methodology used to quantify the contribution of common cause in either category, has been the methodology described in NUREG/CR-4780, Vol's I and II, Procedure for Treating Common Cause Failures in Safety and Reliability Studies (Ref. 3.3-11), where we adopted the MGL methodology.

In addition to performing an update of the common cause data base, a plant common cause walk down was performed to identyify any conditions that exist in the field that either represents an unusally strong defense against a particular common cause failure or represents an unusually high exposure to certain types of common cause failures. This cause-defense common cause analysis was performed following the methodology described in NUREG/CR-5460, A Cause-Defense Approach to the Understanding and Analysis of Common Cause Failures (Ref. 3.3-12).

3.3.4.1 Common Cause Data Analysis Methodology

The IP2 common cause analysis was performed in two parts. In the first section we developed and quantified the common cause failure basic events, by identification of component failure modes within systems that are subject to common cause type failures. This analysis was originally performed during the 1989 update of the IPPSS and followed the guide lines set forth in NUREG/CR-4780.

The second portion of the common cause analysis was to reevaluate the 1989 common cause analysis for continued applicability for the IPE and then to perform a plant walk down to identify either potential plant susceptibilities as a result of plant configuartions or potential defenses against common cause failures. In either case, changes to the specific common cause values would be made to adjust for these findings. This analysis was performed following the guidance set forth in NUREG/CR-5460.

3.3.4.1.1 Development of the Common Cause Data Base

The development of the IP2 IPE common cause data base began with an examination of the existing IPPSS common cause data base. The common cause terms that existed at the conclusion of the original IPPSS study represented the state of the art for common cause analysis during the early 1980's. While many of the original common cause terms did not have to be redefined (the components and the common cause failure mode identified were still considered applicable for IPE system modelling requirements) some existing common cause terms had to be made more system specific. As new systems were modelled for the IPE effort, new common cause terms needed to be be developed. In addition to the development of new common cause terms, all common cause terms were requantified using an updated common cause data base.

The completed common cause data base is presented in Table 3.3-5 of this report.

3.3.4.1.1.1 Data Classification

The procedure outlined in NUREG/CR-4780 was followed to select component groups for common cause failures. The guidelines for the qualitative screening given in NUREG/CR-4780 can be paraphrased as:

1. Identical components performing a redundant function, that are active and are in the same system, should be identified as a susceptible to common cause failure

2. Passive failure modes are generally not included as potential common cause failure modes.

On the basis of these considerations common cause failure events were included in our IPE effort for:

Standby pumps	- failure to start and run
Operating pumps	- failure to run
Valves requiring position change	- fail to open/close
Check valves	- fail to close
EDG's	- fail to start and run
Fans	- fail to start/run
Breakers	- fail to open/close on demand
Batteries	- fail to supply power on demand
Power Operated Relief Valves	- fail to transfer position/open on demand
Relays/Bistables	- fail to perform as required
Air and Motor Operated Valves	- fail to open/close on demand

3.3.4.1.1.2 Reinterpretation of Data Base Events

The events in the PLG common cause data base (Reference 3.3-13, PLG-0500) had to be reanalyzed for their applicability to the IP2 IPE effort. In general, differences between the systems in which the data originated and the system being analyzed arises in two ways. First, there can be differences between systems in design, component type, operating conditions, environment, etc. Secondly, there can be differences between systems in redundancy and the number of redundent components within the system.

The first of these differences are addressed through adjusting weighting factors on the original impact vector. The second of these differences was addressed through the use of mapping impact vector up or down, depending upon the number of components of in the original impact vector and the number of components in our system.

3.3.4.1.2 Quantification of Common Cause Failures

The procedure for detailed CCF analysis described in NUREG/CR-4780 relies on the existence of a data base that provides detailed descriptions of historical events related to both single as well as multiple component failures. However, since CCFs occur at a very infrequent rate, very limited plant specific experience of these failures are expected. Therefore, as recommended by NUREG/CR-4780, data from industry experience was taken from the data base developed by PLG and published in PLG-0500. This data was analyzed and used to make statistical inferences about the frequencies of the common cause events of interest.

The parametric model used to quantify the effect of common cause failures was the Multiple Greek Letter (MGL) method as described in NUREG/CR-4780.

3.3.4.2 Cause-Defense Analysis of Common Cause

Once the reanalysis of the CCF data base was completed, an analysis of cause-defenses against CCF was begun. This CC failure analysis was performed following the guidelines set forth in NUREG/CR-5460.

In performing the defense review, an attempt was made to identify mechanisms for which there is a mismatch between the coupling/defense characteristics of components. The review consists of a search for both similarities and differences between redundant components and their modes of operation and environment.

In NUREG/CR-5460, failure mechanisms are categorized into three groups:

Pre-operational	-	design, construction installation problems
Operational	-	operational, maintenance testing problems
Environmental	-	problems resulting from changes to ambient environment

Pre-operational failure causes are not directly revealed through a walk down/talk through type of review. However, since components are tested or operated in the manner required for accident situations, the presence of such failure causes are likely to have been revealed by now and are therefore of low significance.

The operational failure causes were divided in NUREG/CR-5460 into three groups: error in procedure, systematic error in application, or a systematic single crew error in application. The first of these three groups is largely beyond the scope of a walk down/talk through, but such failure causes are often detectable and correctable, and, therefore of less importance. The remaining two groups are most likely to be significant following changes in procedures, or if they are induced by peculiarities of the conditions local to where the activity is being performed, for example cramped working conditions or poor lighting.

The environmental related failure causes are those most recognizeable during the plant walk down process.

3.3.4.2 Data Screening

In order to determine which common cause failure event needed to be examined for the cause-defenses analysis, an importance analysis of the 1989 core damage model was performed. The measure of importance adopted was the Fussel-Vesely (F-V) importance measure. On the basis of this analysis several common cause failure terms were identified as good canidates for further investigation. These terms then determined in which areas of the plant the walk down needed to focus.

3.3.4.2.1 Coupling Factors and Defenses

This review was performed for all common cause component groups. The fact that the components have been identified in terms of common cause component groups, implies the presence of several coupling factors relating to similarities in design, operation and maintenance. Conversations were held with key personnel in the Maintenance, Test and Failure Analysis department to assertain which, if any, dependencies they preceived as key to common cause failures at Indian Point.

NUREG/CR-5460 identifies certain defensive tactics which can be effective in reducing the coupling mechanism between failures. These defenses include:

Diversity	-	since the common cause failure were initally identified on the basis of their design similarity, this can only apply to methods of operations, testing and/or maintenance .
Physical Barriers	-	these can provide protection against certain environmental causes by providing spatial separation or physical protection, or by decreasing physical connections through removal or administrative control of crossties.
Staggered Testing and Maintenance.	-	The similarities between components and their condition at any one time can be decreased by performing staggered versus non-staggered tests or maintenance.

3.3.4.2.2 Plant Walk Down

Based upon the above discussion, a walk down of the plant was conducted in the following locations:

1 - Emergency Diesel Generator Building
2 - 6.9kV / 480V Switch gear rooms
3 - Battery / MG Set Rooms
4 - Service Water Pump / Strainer Areas
5 - Charging / SIS / RHR / Containment Spray Pump Rooms
6 - Auxiliary Feed Pump Rooms

3.3.4.2.3 Conclusions

Based on the walkdown, discussions with plant personnel and a review of plant procedures, it was determined that the protections against common cause events and the susceptibility to common cause failures at IP2 were not atypical of those at other plants. Therefore the use of common cause factors, based on the method described in NUREG/CR-4780, is determined to be appropriate.

3.3.5 Quantification of Plant Model

The modelling approach utilized in the IPPSS and maintained in both the 1989 update and the current IPE effort is a support state approach (sometimes referred to as the large event tree/small fault tree approach). For the Indian Point Unit No. 2 Level 1 effort, this approach links three event trees. The first tree represents all possible conditions of the electric power support systems, such as the emergency diesel generators and individual AC and DC busses. The intermediate tree represents possible conditions of other support systems such as service water and component cooling. The final tree contains all frontline accident mitigation systems such as auxiliary feedwater and high pressure injection. The system and event tree models were developed and quantified within the RISKMAN risk management software.

The systems are designated as top events on the event tree and are represented by split fractions which describe the unavailibility of the systems under various success criteria and support system boundary conditions. These split fractions were quantified through the use of algebraic system equations which were derived from boolean representations of the combinations of component (or basic event) failures which result in system failure. The split fractions were quantified under uncertainty using basic event parameter distributions stored within the RISKMAN data base (see Section 3.3). The results of the split fraction quantification are shown in the system cause tables as mean values (see section 3.2) and stored within the conditional split fraction data base, as discrete probabilty distributions.

The three event trees in the Level 1 anaylsis are linked by application of split fraction logic rules which place the appropriate initial or boundary conditions on each system consistent with the condition or state of the support system to which it is linked for each sequence. These event tree logic rules (see section 3.1) allow direct treatment of dependencies. In the original IPPSS, the linking of event trees required a binning process at the end of each support system event tree. This process permitted the collapsing of thousands of individual support system conditions into say 30 to 50 support states. This is no longer required by the current RISKMAN architecture since each support system condition is analyzed seperately.

The final product of the event tree linking and quantification process is a listing of all potential accident scenarios leading to successful accident mitigation or core damage together with their associated frequency (see section 3.4). A binning was performed at this point to categorize sequences into plant damage states for the purpose of analyzing results. The logic for this binning process is defined by the binning logic rules associated with each front line system event tree (see section 3.2). The plant damage state results provide the link between the Level 1 and Level 2 model.

The event tree quantification was performed using mean values for the initiating event frequencies and conditional split fraction probabilities. The resulting sequences, which exceeded a cut off of 1.0E-10, were then used to create an important sequence model. Subsequently the important sequence model was solved under uncertainty using the initiating event probability distributions from basic event parameter file and split fraction distibutions from the conditional split fraction data base, to develop an overall uncertainty distributuion for the core damage frequency.

3.3.6 Internal Flood Analysis

The original Indian Point Probabilistic Safety Study (IPPSS) addressed internal flooding both as a separate initiating event (IPPSS Section 7.4) and as a consideration in the fire analysis (IPPSS Sections 7.3.1 and 7.3.2). The conclusion of those analyses was that internal flooding was not a significant contributor to risk at Indian Point Unit No. 2. Based on those previously completed plant specific analyses and the resulting conclusion that internal flooding was of low risk significance given the plant design, the IPE plan for Indian Point Unit No. 2 (Reference 3.3-14) proposed revisiting internal flooding as a coordinated task during the IPEEE. This approach was accepted in a letter dated January 30, 1990, from D. Brinkman (NRC) to S. Bram (Con Edison)(Reference 3.3-15).

3.3.7 References for Section 3.3

3.3-1 "Data Base for Probabilistic Risk Analysis of Light Water Nuclear Power Plants", PLG -0500, July 1989.

3.3-2 NUREG/CR-1278, "Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications", 1983.

3.3-3 NUREG-1335, "Individual Plant Examination: Submittal Guidance", 1989.

3.3-4 EPRI NP-6560-L, Revision 1, "An Approach to the Analysis of EOP-Driven Operator Interactions Using Simulator Measurements for Use in Individual Plant Examinations", 1990.

3.3-5 "Indian Point Station Unit 2 Emergency Operatinig Procedures", Rev. 13, 1991.

3.3-6 EPRI NP-6937, "Operator Reliability Experiments Using Power Plant Simulators", 1990.

3.3-7 "Human Reliability Analysis. A Systems Engineering approach with Nuclear Power Plant Applications", John Wiley & Sons, New York, (NY), pp 107-129, Dougherty, E.M., Jr. and J.R. Fragola, 1988

3.3-8 "Human Reliability Analysis in Loviisa Probabilistic Safety Analysis:, Proceedings of SRE Symposium '86, October 14-16, Otaniemi, Finland.

3.3-9 "Probabilistic Safety Assessment for the Borssele Nuclear Power Plant", Kent (WA) and Erlangen (Germany), Halliburton NUS and Siemens-KWU, 1991.

3.3-10 "Probabilistic Risk Assessment Nuclear Power Plant, Units 1 and 2, for the Individual Plant Examination", Virginia Power and Halliburton NUS, 1991.

3.3-11 NUREG/CR-4780, Vol's I and II, Procedure for Treating Common Cause Failures in Safety and Reliability Studies

3.3-12 NUREG/CR-5460, A Cause-Defense Approach to the Understanding and Analysis of Common Cause Failures

3.3-13 PLG-0500 , "Data Base for Probabilistic Risk and Reliability Studies " PLG, June 1986

3.3-14 Letter dated October 27, 1989, from S. Bram (Con Edison) to Document Control Desk (USNRC), Response to NRC Generic Letter 88-20 and Supplement 1 (60 Day Response)

3.3-15 Letter dated January 30, 1990, from D. Brinkman (NRC) to S. Bram (Con Edison), Review of 60-Day Response to Generic Letter 88-20, Individual Plant Examinations (IPE) (TAC No. 74422)

SECTION 3.4

RESULTS AND SCREENING PROCESS

3.4 Results Analysis Screening Process

For the Indian Point 2 IPE, core damage is defined as the point at which the licensing basis maximum fuel clad temperature of 2200 °F is reached. Although this criteria is somewhat conservative, the additional time available to recover cooling systems before serious core degradation occurs is small and this conservatism is not expected to lead to a significant over-prediction of core damage risk. However, in evaluating the frequency of release of fission products, consideration has been given, in specific circumstances (e.g. station blackout), to recovery of systems and re-establishment of decay heat removal capability following core damage but prior to vessel failure, or prior to containment failure.

In this section, the contributions to core damage frequency are evaluated consistent with the reporting requirements specified in Generic Letter 88-20 (Ref. 3.4-1) and the associated guidance document, NUREG 1335 (Ref. 3.4-2). The following topics are covered.

Application of Generic Letter Screening Criteria

Vulnerability Screening

Decay Heat Removal Evaluation

USI and GSI Screening

3.4.1 Application of Generic Letter Screening Criteria

Generic Letter 88-20 and NUREG 1335 provide specific screening criteria to report potentially important sequences and system failures with respect to core damage and containment performance. Since the IP2 IPE is a support state model (large event tree, small fault tree), the resulting accident sequences can generally be considered as systemic rather than functional in nature. Therefore the screening criteria pertaining to systemic sequences have been applied as follows:

1. All sequences with a contribution to core damage frequency of greater than or equal to 1.0E-07 per year (Table 3.4-1)

2. All sequences that are within the upper 95% of the core damage frequency (Table 3.4-2).

3. All sequences that contribute to Containment Bypass Frequency in excess of 1.0E-08 per year (Table 3.4-3)

4. All sequences that contribute to the upper 95% of the containment failure frequency. (Note: in accordance with Generic Letter 88-20, those sequences which can result in radioactive releases which are greater than or equal in magnitude to WASH-1400 PWR-4 have been included.) Table 3.4-4 shows the contribution of each plant damage state to the containment failure frequency and Table 3.4-5 shows the accident sequences which contribute to each of those plant damage states. See Section 3.4.2.2 for further explanation).

5. A list of all sequences which, but for low human error probabilites (< 0.1) in post initiator operator actions, would have been above the core damage frequency screening criteria (Table 3.4-6).

3.4.1.1 Core Damage Frequency

The base case core damage frequency calculations were performed using a uniform sequence cutoff frequency of 1.0E-10 per year. This generated approximately 5000 sequences and resulted in an total core damage frequency of 3.13 E-05 per year.

Forty two core damage sequences with an annual frequency of greater than 1.0E-07 were identified. These sequences contribute 80% of the total CDF and are included in Table 3.4-1.

The summary of core damage sequences contributing to greater 95% of the total CDF, grouped according to functional sequence type (see section 3.4.3.1), is shown in Table 3.4-7.

The specific events represented by these sequences can be understood by referring to system "top event" and "split fraction" tables given in Section 3.2. In addition, it is helpful to note that the first two characters of any split fraction correspond to the top event designator, that split fractions that end in "F" indicate guaranteed failure due to some preceding condition and that slashes (/) separate the split fractions associated with each segment of the three segment plant model as follows:

/Electric Power Systems/Other Support Systems/Frontline Systems

Finally, to allow easier scrutiny, the sequence listing contains only the failed split fractions. The actual sequence frequencies are calculated using both success and failure terms. The sequences which include success terms can be reviewed in the detailed sequence reports available in RISKMAN.

The top 20 sequences plus two additional ones (22 and 39) which fall into an important group, are described below:

Sequences 1, 3, 4, 22, and 39 are very similar in accident progression and contribute a total of **9.19E-06 (29.4%)** to the overall CDF. The sequences involve a general transient (Reactor Trip, Turbine Trip, Loss of Normal Feedwater, MSIV closure or Loss of Primary Flow), coupled with a loss of Auxiliary Feedwater (split fraction L11) and Primary Bleed (split fraction O11). The major contributors to Auxiliary Feedwater failure are common cause and random failures of the motor driven pumps, and random failure of the turbine driven pump to start and run. The dominant contributor to failure of primary bleed are failure of timely operator response and failure of PORV/ Block valves to open. All support systems, containment heat removal, late vessel injection and containment sprays are available.

Sequence 2 contributes **3.21E-06 (10.2%)** to the overall CDF. The sequence is initiated by a Small LOCA with Auxiliary Feed Water and High Pressure Injection operating. The operators successfully initiate Post LOCA Cooldown to reduce the RCS pressure below the RHR/ Recirculation pump shut off head. However, following exhaustion of the RWST core damage occurs due to loss of injection in the recirculation phase (split fraction LR6). The dominant contribution to failure of Low Pressure Recirculation is operator error to re-align to the recirculation mode. All support systems, and containment heat removal via the fan coolers are operable. However, containment sprays (split fraction CSF) are assumed unavailable at the time of vessel failure due to preceding Recirculation System failures.

Sequence 5 contributes **1.84E-06 (5.9%)** to the overall CDF. The sequence is initiated by a large LOCA event with successful injection from the accumulators and RHR pumps. However, following exhaustion of the RWST, core damage occurs due to loss of injection in the recirculation phase. The dominant contribution to failure of Low Pressure Recirculation (split fraction LR1) is operator error to re-align to the recirculation mode. All support systems, and containment heat removal via the fan coolers are operable. However, containment sprays are assumed unavailable at the time of vessel failure due to preceding Recirculation System failures.

Sequence 6 contributes **1.22E-06 (3.9%)** to the overall CDF. The sequence is initiated by a medium LOCA, with successful injection from the high pressure injection pumps and accumulators. However, Post LOCA cooldown (split fraction DZ2) is not initiated in sufficient time to permit Low Pressure Recirculation upon exhaustion of the RWST and High Pressure Recirculation fails. The dominant contribution to failure of timely Post LOCA cooldown is operator error. The dominant contribution to failure of High Pressure Recirculation (split fraction HR6) is operator error to correctly align to the recirculation mode. All support systems, and containment heat removal via the fan coolers are operable. However, containment sprays (split fraction CSF) are assumed unavailable at the time of vessel failure due to preceding Recirculation System failures.

Sequence 7 contributes **8.87E-07 (2.8%)** to the overall CDF. The sequence is initiated by a Small LOCA with successful secondary side heat removal. However, core damage occurs due to failure of RCS makeup in the injection phase resulting from failure of the RWST supply (split fraction RW2) to the high pressure injection pumps. The dominant contribution to failure of the RWST supply is the unidentified closure of the tank outlet valve (e.g. disk/stem separation). Containment heat removal is available via the fan coolers. However, late injection and containment sprays are conservatively assumed to be unavailable in the sequence binning (and are not explicitly challenged in the event tree in order to avoid unnecessary complication of the tree structure).

Sequence 8 contributes **7.94E-07 (2.5%)** to the overall CDF. The sequence is initiated by a Small LOCA with successful secondary side heat removal. However RCS make up fails in the the injection phase due to a failure of High Pressure Injection system (split fraction HP1) coupled with a failure to initiate Core Cooling Recovery in a timely manner (event Y11). Failure of High Pressure Injection is dominated by common cause and random pump failures to start and run. Failure of Core Cooling Recovery is dominated by operator error to initiate RCS depressurization which is required for recovery in a timely fashion. All support systems, containment heat removal, late vessel injection and containment sprays are available.

Sequence 9 contributes **5.49E-07 (1.8%)** to the overall CDF. The sequence is initiated by a loss of offsite power, with successful start of EDG No 21. However, EDGs 22 and 23 fail (split fractions G23 and G21) and AC power from offsite or the gas turbines is not recovered at 1/2 hour or at 1 hour (split fractions P11, T11, P12, and T12). The motor driven Auxiliary Feed Water pumps, which are powered from buses 3A and 6A (EDGs 22 and 23 respectively) are not supported and the turbine driven AFS pump fails randomly (split fraction L13). Primary Bleed is insufficient due to lack of power to one of the two PORV block valves. All support systems (except buses 2A, 3A and 6A), Containment Heat Removal, Late Injection and Containment Sprays are operable.

Sequence 10 contributes **5.29E-07 (1.7%)** to the overall CDF. The sequence is initiated by a small LOCA with subsequent failure of both ESFAS trains A and B (split fractions EA1 and EBC). As a consequence of ESFAS failure, all safeguards (AFS, SI etc) are assumed to be failed. That is, following the original IPPSS general modeling rule, no credit was taken for manual backup of automatic signals unless sequences were shown to be significant risk contributors. The dominant contribution to failure of safeguards actuation is a hardware failure associated with one of the logic channels coincident with the second channel being unavailable during a periodic test.

Sequence 11 contributes **5.05E-07 (1.6%)** to the overall CDF. The sequence is initiated by a medium LOCA with successful high pressure injection. However, make up is inadequate due to the failure of any one of the three Accumulators (split fraction AS1) on the intact RCS loops to inject. All support systems, containment heat removal, late vessel injection and containment sprays are available. (Note: the accumulator success criteria may be conservative for medium LOCAs).

Sequence 12 contributes **4.93E-07 (1.6%)** to the overall CDF. The sequence is initiated by a Steam Generator Tube Rupture (SGTR) with successful secondary side cooling and high pressure injection. The ruptured generator is initially isolated, but overfill occurs due to a failure to achieve early cooldown and depressurization of the RCS (split fraction O41). Make up to the RCS is ultimately lost due to a failure of late cooldown and depressurization and exhaustion of the RWST (split fraction O5A). In this SGTR sequence, the ruptured SG is isolated and although the initial RCS pressure at core damage will cause the safety or atmospheric relief valve to lift, it recloses when the RCS pressure drops retaining a substantial amount of fission products. The dominant contributor to the failure of early and late depressurization is the common cause failure to open one of the atmospheric relief valves on the intact steam generators.

Sequence 13 contributes **4.48E-07 (1.4%)** to the overall CDF. The sequence is initiated by a Loss of Offsite Power with a failure of Emergency Diesel Generators 21 and 22 (Bus 5A 2A, 3A) (split fractions G13 and G2C). As a consequence of loss of power on bus 5A and 3A, the EDG building Ventilation (split fraction STF) is unavailable and the remaining diesel fails due to adverse temperature. AC power from offsite or the gas turbines is not recovered at 1/2 hour or at 1 hour. The motor driven Auxiliary Feed Water pumps, which are powered from buses 3A and 6A are not supported and the turbine driven AFS pump fails randomly (split fraction L13). With no AC power and no turbine driven AFS pump, both secondary and primary cooling are unavailable and core damage results. However offsite AC power is recovered prior to vessel failure and Containment Heat Removal, Late Injection and Containment Sprays are successful. (Note: although no cooling is available to the RCP pumps seals in this sequence, core damage occurs early due to lack of core cooling, and thus eventual failure of the RCP seals is unlikely to impact the progression of this accident.)

Sequence 14 contributes **4.29E-07 (1.4%)** to the overall CDF. The sequence is initiated by a Loss of Offsite Power with a failure of Emergency Diesel Generators 21 and 22 (Bus 5A, 2A and 3A). As a consequence of loss of power on bus 5A and 3A, the EDG building Ventilation is unavailable (split fraction STF)and the remaining diesel generator (EDG 21) fails due to adverse temperature. AC power from offsite or the gas turbines is not recovered at 1/2 hour, 1 hour or at 3 hours (split fractions P11, T12, P21, P31, T32). The motor driven Auxiliary Feed Water pumps, which are powered from buses 3A and 6A (EDGs 22 and 23 respectively) are not supported but the turbine auxiliary feedwater pump is successful. All DC battery power is depleted at 3 hours but the operators are successful in controlling the AFS pump locally and monitoring the plant condition utilizing pneumatic instruments. However, an RCP seal LOCA develops due to loss of all seal cooling and core uncovery (core damage) occurs before power can be restored from offsite or the Gas Turbines (split fractions C13 and C27). However offsite AC power is recovered prior to vessel failure and Containment Heat Removal, Late Injection and Containment Sprays are successful.

Sequence 15 contributes **4.05E-07 (1.3%)** to the overall CDF. This sequence is initiated by a Steam Generator Tube Rupture with failure of both trains of ESFAS (split fractions EA1 and EBC). As discussed under Sequence 10, this condition is assumed to result in a loss safeguards including auxiliary feedwater and high pressure injection. Core damage results but the ruptured generator is isolated and the relief valve closes after the RCS has depressurized.

Sequence 16 contributes **2.93E-07 (0.9%)** to the overall CDF. This sequence is initiated by a LOCA beyond ECCS capacity and results directly in core damage due to inadequate makeup. Containment Heat Removal, and Containment Sprays are operable.

Sequences 17 and 19 are similar and contribute a total of **4.74E-07 (1.5%)** to the overall CDF. These sequences are initiated by a loss of DC bus 21 or 22, coupled with a loss of Auxiliary Feedwater (split fraction L11) and Primary Bleed (split fraction O1F). The dominant contributors to Auxiliary Feedwater failure are discussed under Sequence 1 above. Primary Bleed failure is guaranteed due to loss of DC power to one of the two PORVs since both are required. Containment heat removal, Late Vessel Injection and Containemnt Sprays are available.

Sequence 18 contributes **2.32E-07 (0.7%)** to the overall CDF. This sequence is initiated by a Large LOCA. Core damage results due to failure of Low Pressure Safety Injection (split fraction LP1). The dominant contributor to failure of injection is common cause or random failure of both low pressure pumps. Containment Heat Removal and Containment Sprays are operating.

Sequence 20 contributes **2.23E-07 (0.7%)** to the overall CDF. This sequence is initiated by a Steam Generator Tube Rupture with success of Secondary Side Cooling and High Pressure Injection but failure of early and late isolation of the ruptured SG (split fractions OS1 and SO1). However, although the operators successfully initiate late cooldown and depressurization, the RHR system fails in the shutdown cooling mode (split fraction LR4). The major contributors to the failure of early and late isolation of the ruptured SG are failure to close the AFS Turbine Driven Pump Steam Supply Valves from the ruptured generator (MS-41 or MS-42) and failure of the Safety Relief Valve to reclose. The dominant contributors to the failure of RHR are the hotleg suction valves (730/731) failing to open.

3.4.1.2 Containment Performance Screening

The containment sequences and associated source terms are evaluated in Section 4. Twenty six source term release categories were developed for use in grouping the containment sequences. The various source term classes have been grouped into five general release types for convenience and clarity as follows:

TYPE I	I,CS release fraction > = 0.2
TYPE II	I,CS release fraction > = 0.04
TYPE III	I,CS release fraction > = 0.002
TYPE IV	I,CS release fraction < 0.002
TYPE V	No Containment failure - normal leakage

The magnitude of only Type I and II releases exceed the WASH 1400 PWR-4 category, which is the containment performance reporting criteria specified in Appendix 2 of the Generic Letter (Ref. 3.4-1). The magnitude of the remaining IP2 release types are less than the screening criteria.

The sequence characteristics which are important to source term magnitude, composition and timing are represented in the source term logic diagram, shown in Figure 3.4-1. A detailed discussion can be found in section 4.7.

The frequency and characteristics of each release type are discussed below:

3.4.1.2.1 Type I Release

Type I releases are associated with core damage events involving a Interfacing Systems LOCA which occurs outside containment, an unmitigated Steam Generator Tube Rupture in which isolation is not achieved following reduction in pressure below the relief valve setting (e.g. with a stuck open relief valve or other unisolated valve) and postulated Alpha mode containment failures.

The total frequency of IP2 Type I releases is 3.99E-07 per year. Alpha Mode failures have a negligible contribution. The sequences which contribute in excess of 1.0E-08 per year to Type I releases are listed in Table 3.4-3.

3.4.1.2.2 Type II Release

Type II releases are associated with:

- unmitigated Steam Generator Tube Rupture accidents with a cycling safety relief valve which closes when the RCS depressurizes, terminating the release,
- induced tube rupture accidents,
- transients/LOCAs with no in-vessel debris cooling and late containment failure with no containment spray recirculation (Source Term Category (STC) 16 and 17),
- transients/LOCAs with no in-vessel debris cooling and early containment failure (STC 2-9, with or without sprays).
- sequences with no in-vessel debris cooling and failure of containment isolation also fall into this category.

The important contributors to this release category are as follows:

Steam Generator Tube Rupture with Cycling Safety Valve (Type II Release)

These sequences are listed separately, since although they involve an initial release which does not challenge containment mitigation systems in the normal sense, they include successful release termination and their release magnitude and timing is more aligned with containment failure sequences listed below than with containment bypass type sequences listed above. That is, these sequences fall neither into a classic bypass nor a containment failure classification. The total frequency of these sequences is 1.54E-06 per year corresponding to STC 25 as indicated in Table 3.4-4. Eighty one percent of these SGTR sequences come directly from the Steam Generator Tube Rupture initiating event leading to plant damage state (PDS) 48B. The sequences that cobtribute to PDS 48B are listed in Table 3.4-5. The remaining contribution to STC 25 comes mainly from sequences involving induced tube ruptures following a transient event. These sequences are listed in Table 3.4-5 under PDS 24.

Containment Failure with Release Magnitude in excess of WASH 1400 PWR-4 (Type II Release)

The total frequency of containment failure resulting in a radioactive release of magnitude greater or equal to WASH 1400 PWR-4 is 1.88E-06 per year (excluding the SGTR sequences mentioned above). Those plant damage states which contribute to the upper 95% of this type of release are listed in Table 3.4-4. The individual sequences which contribute to those plant damage states are listed in Table 3.4-5.

It should be recognized that each plant damage state (and, therefore, each core damage sequence) may result in more than one containment failure mode. The quantified containment event trees give the likelihood of each failure mode given the PDS. Consequently, the PDS frequency for each containment failure mode or each release category may be less than the total PDS frequency.

3.4.1.2.3 Type III or IV Release

Type III releases are associated with no in-vessel debris cooling, and late containment failure with successful late spray operation. The dominant contributors include station blackout, loss of secondary cooling or seal LOCA, with no power recovery before vessel failure and late containment failure (despite late power recovery) (STC 12 and 13).

Type IV releases are associated with sequences in which there is a late containment failure but sprays are only available early, late-late containment failures which occur well beyond 24 hours (e.g. basemat melt-through) or sequences in which the debris is cooled in vessel but the containment is not isolated. Type IV releases are dominated by loss of offsite power and failure of auxiliary feedwater and failure of primary system bleed and feed with Containment Sprays operating but no containment heat removal (i.e. fans or heat sink) (STC29).

The total frequency of containment failure resulting in a radioactive release of magnitude less than WASH 1400 PWR-4 is 1.30E-06 per year. The Plant Damage States and individual sequences are not reported here since their associated release magnitude falls below the screening criteria discussed at the beginning of Section 3.4.1.

3.4.1.3 Comparison of Results With and Without Low Human Error Rates

In developing the system models, operator actions, which are directed by procedures and required for accident mitigation, have been included and evaluated. Generally, where an action is accomplished by an automatic system, such as start up of high pressure injection by an SI signal, the model conservatively takes no credit for recovery if the automatic action fails, despite the fact that direction is given in the EOPs. The one exception to this rule is applied following the failure of an automatic reactor trip where manual scram action has been included within the reactor trip function model.

Certain sequences which include operator actions have a frequency below the 10^{-7} per screening criteria for listing systemic core damage sequences. In order to ensure that no sequences escape examination solely due to low human error probabilities (HEPs), the entire model was re-evaluated substituting a value of 0.1 for all HEPs. The most significant 50 sequences which did not previously meet the core damage frequency screening criteria of 10^{-7} per year, are shown in Table 3.4-6. The types of sequences and associated operator errors which are raised above the screening criteria are discussed below in order of significance:

1) Loss of Offsite Power AND failure of the three EDGs due to loss of the Fuel Oil supply to the EDG day tanks in combination with power restoration failures leading to: (a) RCP seal LOCA followed by ECCS failure, or
(b) loss of secondary side heat removal.

The operator actions associated with these sequences include:

(a) Failure to reset the MCCs 24A, 27A and 29A (IPOPFO), which supply the EDG fuel oil pumps. The immediate steps of EOP E-0 direct operators to perform this action. Operators are well trained and execution of the step is second nature. Furthermore, a low day tank level would initiate an "EDG trouble alarm" in the control room which would provide a second reminder to take action. Failure of the initial operator action is assessed to be 3.3E-03/d and failure to respond to the trouble alarm (1.1 E-02/d), resulting in an overall error probabilty of 3.6E-05. Finally the MCCs have recently undergone substantial modifications which have significantly simplified the required local MCC manipulations and reduced the possibility of making errors. Operators would generally have to fail to reset multiple MCCs in order for the action to be considered a failure since any one fuel oil pump can supply any of the three EDGs. (Note: since the cut off date for the

IPE analysis, the power supply for Fuel Oil pump 23 has been transferred to MCC 26B which is automatically re-loaded onto 480v-ac bus 6A following loss of offsite power. The significance of this operator action is therefore substantially reduced with the current plant configuration).

(b) Failure to switchover to Recirculation (IPOPRA), which is a purely manual action at IP2. Failure results in a loss of RCS make up when the RWST supply is exhausted. The EOP directives associated with this action are concise and well practiced. The human error probability developed for this action (3.6E-04/d) is again consistent with other industry PRAs.

2) Steam Generator Tube Rupture with failure to isolate the ruptured Steam Generator (early and late) and failure to cooldown and depressurize the RCS prior to the exhaustion of the RWST.

Each one of the split fractions (OS1, O5E and S03) included within the sequence includes operator actions as single failure (IPOPIS=1.7E-02, IPOPC1=2.4E-04, IPOPC2=4.9E-04, IPOPS1=1.2E-04) and thus it is not surprising that this sequence increases in significance when operator action probabilities are artificially set to 0.1. The IP2 EOPs for SGTR mitigation are concise and well practiced. Special provisions have been incorporated to accomplish early isolation of Auxiliary Feedwater if a ruptured SG is detected (ie. prior to entering the SGTR mitigation EOP E-3), in order to minimize the possibilty of overfill. A plant specific thermal hydraulic analysis has been performed as part of the IPE, to determine the time windows available for taking actions following SGTR and shown to be in general agreement with generic Westinghouse analyses. These time windows, together with IP2 simulator experience have been factored into a systematic human reliabilty analysis to derive appropriate operator failure probabilities. The values used are consistent with other industry PRAs. Dependencies between the actions have been identified and incorporated into the sequence quantification.

A similar sequence (SGTR * OS1 * SO1 * LR4) does meet the IPE screening criteria for reporting and is included in Table 3.4-2.

3) Several General Transient initiating event sequences with failure of Auxiliary Feedwater, success of Primary Bleed and Feed and failure of Recirculation.

These sequences have increased in significance primarily due to the operator error associated with the failure to switchover to Recirculation (IPOPRA), which is a purely manual action at IP2. Failure results in a loss of RCS make up when the RWST supply is exhausted. This action is discussed previously in Item 1. The human error probabilities developed for this action are again consistent with other industry PRAs.

4) Several General Transient initiating events with a stuck open pressurizer PORV path, successful secondary side cooling and high pressure injection, but failure of Recirculation.

These sequences have increased in significance due to the operator errors associated with failing to close the PORV block valves in order to isolate a stuck open PORV (IPOPB1), as well as the operator error associated with switchover to Recirculation, as discussed under 3 above. The existence of a stuck open valve is easily identifiable by the operators and EOPs (E-0, step 25, ES-0.1, step 7) clearly direct operators to check the valve positions following a transient event. At least one hour is available after a stuck open valve event to recognize and correct the situation. The current HEP probability (mean value 3.9E-03) has been evaluated in a systematic manner using the guidance provided in NUREG/CR-4772 and is consistent with other industry PRAs.

5) Several General Transient initiating event sequences with failure of Auxiliary Feedwater and Primary Bleed, coupled with additional system failures including late vessel injection and containment sprays, which do not impact core damage but do have an effect on the final plant damage states.

The core damage sequences here are similar to those already included as reportable sequences in Table 3.4-2, with some additional, non-core damage related system failures, as noted above. The reasons for the increased significance of these sequences are the operator errors associated with the initiation of Primary Bleed (IPOPFB), Low Pressure Recirculation (IPOPR6) and Containment Spray (IPOPR9) all of which are single system failures modes. The Primary Bleed Operator action is discussed in section 3.1.1. Operator actions associated with Recirculation switchover and Containment Spray are well proceduralized and practiced actions and the assigned operator errors are consistent with other industry PRAs.

6) Loss of Component Cooling Water Initiating Event with failure of automatic and manual reactor trip, failure of emergency boration due failure of CCW to charging pumps and failure to locally deenergize MG sets within 10 mins. Each of these operator actions has been assigned a human error probability of 4E-03/d with appropriate dependencies between actions incorporated.

The frequency of this sequence has increased in significance due to the human action associated with deenergizing MG sets (event MD) and is coupled with manual backup of the automatic scram signal. Verification of reactor trip is the first step in the EOPs, is part of the operators response to every initiating event and immediate response and is instinctual on the part of the operator.

3.4.1.4 Sensitivity Studies

Two sensitivity studies were performed. The first addresses the impact of the RCP Seal LOCA Model on the estimate of core damage frequency and the second addresses the impact of the mission time assumed for the AFS turbine driven pump.

3.4.1.4.1 RCP Seal LOCA Model

In the original IPPSS Analysis, Loss of Offsite Power with failure of two diesel generators, RCP seal LOCA and failure to recover AC power within one hour was the highest contributor to core damage from internal events. This arose for two reasons which are no longer valid in the current IP2 base case IPE model, namely:

> i) At the time of the original IPPSS analysis, Component Cooling Water Pump 21 was supplied from EDG 21 and both Pumps 22 and 23 were supplied from EDG 22. Thus, even if station blackout was not a consequence of two diesels failing, loss of two specific EDGs (21 and 22) resulted in loss of Component Cooling flow to the RCP thermal barriers with the resulting potential for a seal LOCA (since restart of charging pumps was not considered in the model). Since that time, the emergency power supply for CCW pump 23 has been transferred to Bus 6A which is supplied from EDG 23. As a result, failure of two diesels no longer poses an immediate threat to the RCP seals.
>
> (ii) In the original IPPSS model it was assumed that, in the absence of RCP thermal barrier cooling and seal injection, complete seal LOCA would occur within 30 minutes. Core uncovery would then result unless RCS make up from the high pressure injection pumps could be provided within an additional 30 minutes (ie. 1 hour after the initial transient). Thus, in the case of station blackout, some form of AC power recovery was required within 1 hour to prevent core damage. As part of this IPE study, a more sophisticated seal LOCA model has been developed based on data provided in WCAP-10541. This model recognizes that the time of seal failure and the leakage rate are time dependent variables which are combined in a model which represents the distribution of probability of core uncovery versus time after loss of seal cooling. Using, this model, the probability of core uncovery at 1 hour after seal LOCA (with no injection available) is $< 10^{-3}$ and only becomes a certainty (probability = 1.0) after approximately 10 hours.

Conversely, as part of this IPE study the requirement for successful operation of the EDG Building Ventilation System, in order to maintain the building temperature below a maximum ambient operating temperature, has been recognized and incorporated into the model. This building ventilation is powered from only two EDGs (21 and 22). Thus failure of EDG23 and consequently station blackout is assumed to occur if EDG 21 and EDG 22 fail or if the EDG building ventilation system fails independently.

In summary therefore, both the original IPPSS model and the new IPE model show a dependence on two specific diesel generators following a loss offsite power event, although for two very different reasons. The difference is that, the IPPSS used a very simplistic and conservative seal LOCA model than is now considered to be appropriate by the industry. The more sophisticated model which has been subsequently developed based on a very substantial technical effort, has been used as the basis of the seal LOCA treatment in the Indian Point 2 IPE.

A sensitivity study has, however, been performed which considers the impact on the estimated core damage frequency, if the original IPPSS RCP seal LOCA model is applied. The analytical approach for changing the Loss of Offsite Power Model and the results are included in Appendix IV. In summary, the sensitivity analysis assumes an RCP Seal LOCA will occur in 1/2 hour if no cooling is available, and core damage will result within an additional 1/2 hour if no RCS make up is available. A comparison of the resulting core damage frequency results are as follows:

	Base Case	Sensitivity Study
LOSP - SBO	4.467E-06	2.883E-05
LOSP - Non SBO	1.059E-06	1.674E-06
Total CDF (all initiators)	3.130E-05	5.573E-05

The LOSP core damage sequences exceeding 10^{-7} per year are listed in Appendix IV together with the Top Event Importance Analysis Results. As can be seen the contribution from Station Blackout to core damage frequency increases by a factor of approximately 6. The most important sequences are those resulting from a station blackout caused by the failure of EDGs 21 and 22 which support the EDG Building Ventilation system. AC power is not recovered either from offsite or the Gas Turbines and core damage results due to an RCP seal LOCA with no RCS make up available.

3.4.1.4.2 AFS Turbine Driven Pump Mission Time

As is evident from the dominant core sequences described earlier in Section 3.4.1.1 as well as from vulnerability and importance analyses discussed in Section 3.4.2, loss of Auxiliary Feedwater following a general transient is a significant contributor to the base case core damage frequency. Whereas the unavailability of the motor driven AFS pumps comes mainly from failures to start on demand, which are data driven parameters, the unavailability of the turbine driven pump is dominated by failures to run (during accident mitigation). That being the case, the assumed time period for which the turbine driven pump is required to run (the mission time) is an important factor in determinig the unreliability of the turbine driven pump and subsequently has an important impact on the overall unavailability of AFS.

The assumed turbine driven pump mission time in the base case analysis is 24 hours. In practice the operating procedures and technical specifications would guide the operators to initiate a cooldown and depressurization of the RCS within approximately an hour after plant trip. Based on the maximun permissable cooldown rate, RCS temperature and pressure conditions which permit the use of RHR operating in the shut down cooling mode, would be expected to be achieved within 8 hours. This would negate the need for continued AFS operation. It is also quite possible that, even if RHR shut down cooling was not operable after 8 hours, any repairs necessary to restore the operability of the motor driven AFS pumps would have been completed.

A sensitivity analysis has therefore been performed which assumes the mission time for the AFS turbine driven pump, in the "all power available" conditions, is 8 hours instead of 24 hours in the base case.

The impact of this sensitivity calculation was to reduce the unavailability of AFS on demand (all power available support state) by 40% from 1.0E-04 to 6.1E-05. The calculated core damage frequency is reduced by 14% from 3.13E-05 to 2.70E-03.

3.4.2 Vulnerability Screening

A concise definition of "vulnerability" has not been given in the NRC documentation associated with the performance and reporting of the IPE (Refs. 3.4-1 and 3.4-2). In a response to questions contained in Appendix C to the IPE Submittal Guidance Document, mention is made of expanding sequences that are above the screening criteria to determine if a weakness exists. Such weaknesses may be defined as a vulnerability, and a risk reduction measures further evaluated. In another response it is suggested that a vulnerability is in fact an outlier (some component failure or human error which by itself contributes significantly more to risk than others, eg. a factor of three or more).

In this study two basic approaches have been adopted in analyzing the results of the IPE to determine if a vulnerability exists or not.

1) Categorization of sequences into Functional Accident Sequence Groups and comparison of Functional Group Frequencies with the criteria provided in the NUMARC Severe Accident Issue Closure Guidelines Document (Ref. 3.4-3).

2) Perfomance of various importance analyses to determine the most significant contributors to core damage frequency, important fission product release categories and decay heat removal functions.

3.4.2.1 Comparison of Functional Sequences with NUMARC 91-04 Guidelines

The Severe Accident Closure Issue Guidelines developed by NUMARC, suggests allocating accident sequences which have similar characteristics into a relatively small number of groups, termed Functional Accident Sequences. An example grouping scheme is provided for both PWRs and as BWRs. Furthermore, an evaluation process is provided which recommends an approriate utility response depending upon the mean frequency of core damage associated with each individual sequence group and whether or not containment bypass is involved.

The IP2 Core Damage Sequences with a frequency of >= 5 x 10^{-9}, which represents 95% of the overall core damage frequency, have been categorized according to the scheme provided in Table B-2 of NUMARC 91-04. The allocation of IP-2 sequences to these categories is shown in Table 3.4-2. The description and frequency of each functional sequence group is shown in Table 3.4-7.

3.4.2.1.1 Evaluation of Non-Bypass Sequences

The evaluation criteria for Non-Bypass sequences are given in Table 1 of NUMARC 91-04.

There are no IP2 functional sequence groups which fall into the highest frequency range (> 10^{-4} per year or > 50% of the total core damage frequency) and most demanding utility response.

IP2 Functional Sequence Group IA sequences fall at the lower end of the second frequency range (10^{-4} to 10^{-5} per year or 20 to 50% of the total core damage frequency). The suggested utility response in this case is to:

1) Find a cost effective treatment in the EOPs or other plant procedure or minor hardware change with emphasis on prevention of core damage.

2) If unable to satisfy above response, ensure Severe Accident Management Guideline (SAMG) is in place with emphasis on prevention /mitigation of core damage or vessel failure or containment failure.

IP2 Functional Sequence Groups IIA, IIIA, IIIB, IIIC, IIID, IV and VC fall at the middle to lower end of the third frequency range (10^{-5} to 10^{-6} per year). The suggested utility response is to:

Ensure SAMG is in place with emphasis on prevention /mitigation of core damage or vessel failure or containment failure.

IP2 Functional Sequence Groups IB and IIB fall into the lowest frequency range ($<10^{-6}$ per year) for which it is suggested that no specific action is required.

Thus with respect to Non-Bypass sequences, application of the NUMARC guidelines suggests that only IP2 Functional Sequence Group IA would require further attention at this time with regard to exploring additional mitigative measures. Reference to Table 3.4-2 indicates that approximately 70 per cent of the Functional Sequence Group IA is derived from general transients with failure of secondary side heat removal (Auxiliary Feed Water System - split fraction L11) and Primary Bleed (split fraction O11). The following items are the major contributors to failure:

Auxiliary Feedwater (split fraction L11)

Common Cause failure of MD pumps and random failure of TD pump	5.57E-05	54.6%
Random failure of both MD pumps and the TD pump	1.39E-05	13.6%
Maintenance of any pump and random failure of the remaining two pumps	1.187E-05	11.6%
Operator error in aligning system (pre accident)	9.68 E-06	9.5%
Other	1.07E-05	10.5%
	1.019E-04	100%

(Turbine driven pump failure is dominated by failure during operation... 24 hour mission time. Motor driven pump failure is dominated by failure to start)

Primary Bleed (split fraction O11)

Operator fails to align/open PORVs within allowable time window	7.10E-03	39.7%
PORV fails to open	7.49E-03	41.8%
Block valve fails to open	3.18E-03	18.5%
	1.79E-02	100%

Auxiliary Feedwater failures are dominated by data driven, random and common cause hardware failures. The failure probabilities for these items is consistent with generic industry experience and consequently, other than emphasize the importance of this system to Operations, Test and Maintenance personnel, no additional improvements which would provide a measurable increase in system reliability are feasible. However, the assumed mission time, 24 hours, for the AFS pumps following a general transient is conservative under all power available conditions, and a sensitivity study (see Section 3.4.1.4.2) using a more realistic mission time of 8 hours, indicates a reduction of 40% in the AFS calculated unavailability.

The unavailability of Primary Bleed has important contributions from both hardware and the operator. Again the hardware failures are data driven and their probability values are consistent with industry experience. However, the hardware modeling is somewhat conservative since it is assumed that both block valves are normally closed, whereas the present operating practice is to operate with the valves open unless excessive PORV leakage prevents this. Additional experience is needed to develop a sufficient data base to determine the fraction of time the block valves will be open and allow the model to be updated. The human error contribution to Primary Bleed has been carefully assessed using a systematic approach. The specific procedural cue (SG level 40% Wide Range), and plant specific PORV capacity to Power ratio have been used to determine the time window for successful operator action. The time window is relatively short (450s) although this does not represent a vulnerability, however, it would be impacted by cueing the operator action earlier (ie. before the SG level reaches 40% wide range).

Finally, no credit in the event tree modeling has been taken for the recovery of main feed water/condensate, following a transient although it is procedurally directed by the EOP's, as an action to be attempted when the minimum flow requirements from the AFS are not met and the level in all four steam generators is less than 5% on the narrow range. The exclusion of FW/condensate recovery is a conservatism. However, the original IPPSS analysis concluded that its inclusion would not noticeably improve the overall feedwater availability based upon only the automatic Auxiliary Feedwater System. Feedwater recovery is a slow manual process. There are also human error dependencies between the AFS Turbine Driven Pump Flow Control/Reset and Main Feedwater Recovery which would make the modeling complex as well as tend to reduce any benefit.

3.4.2.1.2 Evaluation of Containment Bypass Sequences

The evaluation criteria for the Bypass sequences are given in Table 2 of NUMARC 91-04.

There are no IP2 bypass functional sequence groups which fall into the highest frequency range (> 10^{-5} per year or > 20% of the total core damage frequency) or the second range (10^{-5} to 10^{-6} per year or 5 to 20% of the total CDF).

IP2 Functional Sequence Group VB falls in the middle of the third frequency range (10^{-6} to 10^{-7} per year). The suggested utility response is to:

> Ensure SAMG is in place with emphasis on prevention /mitigation of core damage or vessel failure or containment failure.

IP2 Functional Sequence Group VA falls into the lowest frequency range (< 10^{-7} per year) for which it is suggested that no specific action be taken.

Thus with respect to Bypass sequences, application of the NUMARC guidelines suggests that at this time no action is required to explore additional mitigative measures.

3.4.2.2 Importance Analyses with Respect to Core Damage Frequency

3.4.2.2.1 Major Contributors by Initiating Event

One way of examining risk is evaluate the contribution from the initiating events which cause the initial plant transient.

The contributions of each individual initiating event evaluated in the IP2 IPE are listed in Table 3.4-8. The are no exceptionally dominant contributors although Loss of Offsite Power (19%), Small LOCA (18%) and Reactor Trip (14%) are the most significant.

A slightly different type of grouping of the core damage frequency contributors which is often used for comparison with other PRA studies is provided in Table 3.4-9. General Transients (37%), LOCAs (33%) and Station Blackout (14%) are the most prominent groups.

As discussed in Section 3.4.2.1.1, the most likely core damage sequence following a General Transient (RXTRIP, TTRIP, LOFW etc.) is failure of Auxiliary Feedwater and failure to successfully initiate primary system Bleed within the required time window. Loss of Coolant Accidents resulting from breaks in the primary system piping, primarily result in core damage due to loss of RCS make up in the Recirculation Phase.

3.4.2.2.2 Major Contributors by System

Table 3.4-10 lists the IP2 systemic top events according to their importance rank. The importance rank is based on the fraction of core damage sequence contribution by the sequences in which the system or train (as defined by its top event in the plant model) has failed. Guaranteed failures due to preceding top event failures (eg. support systems) are excluded.

Consistent with the Functional Sequence and Initiating Event analyses discussed earlier, Auxiliary Feedwater (L1) and Primary Bleed (O1) analysis are the leading system contributors. They are especially important in core damage sequences following General Transients, LOSP and Small LOCA. Important component failure contributions to these systems are discussed in section 3.4.2.1.1. The importance of Auxiliary Feedwater and Feed and Bleed is somewhat exaggerated in the base case analysis as a result of assuming an extended mission time for the AFS pumps (see section 3.4.1.4.2).

Recovery of AC power from offsite (P1 or P2) or start of the Gas Turbines (T1 and T2) within 1/2 hour or within 1 hr are important since they effectively mitigate the impact of failure of the Emergency Diesel Generators. The time dependent Offsite Power recovery model is based on data provided in NSAC-166 (Ref. 3.4-4) and NUREG-1032 (Ref. 3.4-5). Only two of the three Gas Turbines which serve the IP-2 site have full black start capability at this time (GT1 and 3) and have therefore been credited in this model. Specific maintenance, test and actual demand data have been analyzed to determine the gas turbine unavailability which is relatively high for both GT1 and GT3. Both maintenance downtime and failure to start are significant contributors to unavailability. Section 3.2 gives further details.

Low Pressure Recirculation (LR) failure, is important following Large LOCA, as well as Medium or Small LOCA following successful post LOCA depressurization,. In all cases, operator error in failing to swithchover prior to exhausting the RWST is a significant contributor. The assessed human error probability for IP-2 is consistent with other industry PRAs. However the current human reliability analysis is somewhat conservative for the IP-2 configuration, in that it does not account for the additional recovery time available because the Recirculation System at IP-2 incorporates both RHR and Recirculation pumps. Failure to take prompt action on the part of the operator, may therefore only result in loss of the RHR pumps with the potential for recovery, in some cases, of injection/recirculation using the Recirculation Pumps, prior to core damage. (Note: redundancies are properly accounted in the evaluation of hardware failure contributions.)

Emergency Diesel Generators 21 and 22 are presently the source of all power for the EDG Building Ventilation System. Their failure therefore results in the consequential failure of the remaining EDG 23, causing a station blackout and potential core damage if AC power is not recovered from offsite or the Gas Turbines in a timely mannner.

3.4.2.3 Importance With Respect to Containment Performance

As discussed in section 3.4.1.2, containment performance has been defined in terms of release types. Consistent with the generic letter, the focus of the analysis is on containment failures which lead to releases of magnitude greater than WASH 1400 PWR-4. As discussed in Section 3.4.1.2, IP-2 release types I and II fall into this category. The contributors can generally be broken down as follows:

	Frequency (per year)
Type I (Containment Bypass) Release	3.99E-07
Type II (SGTR without a Stuck Open Valve) Release	1.54E-06 *
Type II (Containment Failure w/o Spray)	1.84E-06
	3.78E-06

* includes induced SGTR contribution (2.52E-07 per year)

The characteristics of each release type are defined in section 3.4.1.2

Thus, the frequency of core damage sequences leading to containment failure or bypass with significant release is 3.78E-06 or 12.1% of the total core damage frequency. (The frequency of significant release as a result of containment building failure, excluding bypass and SGTR sequences, is 1.84E-06 per year, or 5.9% of total core damage frequency.)

The contribution of each plant damage state to Type I and II releases are shown in Table 3.4-4.

The highest contribution to significant release (1.25E-06.. 33.1%) comes from PDS48B, (Containment Event Tree 25, sequence 1) which is an unmitigated SGTR without a stuck open valve on the steam generator with the ruptured tube. The steam generator has boiled dry previous to the onset of radionuclide release from the core, so that little mitigation exists in the secondary system. However, the release from the steam generator terminates when the RCS depressurizes at vessel failure and the SG relief or safety valve recloses. Although the most significant in terms of frequency, the associated release magnitude (STC 25) is one of the smallest TYPE I or II releases (ie. about 2x the WASH 1400 PWR-4 release category magnitude) and the release does not occur for many hours (12-15 hours) after the occurrence of the initiating event. The most significant contribution to PDS 48B comes from a failure of both early and late cooldown and depressurization due to both hardware and operator failures which eventually results in a loss of RCS makeup. (See also discussion of sequences 12 and 15 in section 3.4.1.1 and PDS48B in Table 3.4-5).

The second highest contributor to significant release (4.63E-07..12.3%) comes from PDS46, small/medium LOCA with failure of all ECCS and containment safeguards due to ESFAS failures. The dominant containment failures are described by CET 28, sequences 16 and 18, which involve late containment failure either in a leak mode (STC 16) or rupture mode (STC 17). In either case the release magnitude is again one of the smallest TYPE I or II releases (ie. less than 2x the WASH 1400 PWR-4 release category magnitude). The most significant contribution to PDS 46 comes from a small LOCA with failure of both trains of ESFAS.

The third highest contribution (4.48E-07...11.9%) comes from PDS 45, small/medium LOCA with successful containment heat removal but no sprays. Subsequently, the containment heat removal function fails due to environmental conditions within the containment. The most significant containment failure modes and release are described by CET 27 sequences 16 and 18, and are identical to those described for PDS 46 above. The most significant contribution to PDS 45 comes from a small LOCA with successful make up in the injection phase and successful post LOCA depressurization but failure in the Recirculation phase. Operator error is the main contributor to Recirculation failure.

The fourth highest contributor to significant release (3.72E-07...9.8%) comes from PDS48A, unmitigated SGTR with a stuck open valve on the ruptured generator (CET 29, Sequence 1). In this case the ruptured SG is not isolated when the RCS depressurizes at vessel failure and the release continues. Due to some radionuclide deposition on the surface of the primary and secondary systems, the release (STC 24) is less severe than the interfacing system LOCA (Event V) case (i.e. about 6x the WASH 1400 PWR-4 release category magnitude based on cesium iodide release fraction). The most significant contribution to PDS48A comes from failure to isolate the ruptured steam generator and failure of RHR in the shutdown cooling mode (see Table 3.4-5).

The fifth highest contributor to significant release (2.52E-07...6.7%) comes from PDS 24, a transient with containment heat removal, sprays and late vessel injection available. The predominant containment failure mode is an induced steam generator tube rupture (CET 11, sequence 115) which is assigned to STC 25. PDS 24 is dominated by general transient initiating event followed by failure of auxiliary feedwater and feed and bleed (see Table 3.4-5 for other contributors).

The sixth highest contributor to significant release (2.42E-07...6.4%) comes from PDS 21, Station Blackout with no AC power recovery prior to containment failure. The dominant containment failure modes are described by CET 9, sequences 73 and 75 and radionuclide release are again represented by source term categories STC 16 and 17. PDS 21 is dominated by a loss of offsite power initiating event with failure of emergency diesel generators 21 and 22 which fails the EDG Building Ventilation. Subsequently the third EDG is failed due to adverse room temperature resulting in station blackout. The turbine driven AFS pump fails randomly and primary feed and bleed is unavailable due to lack of AC power. (See Table 3.4-5 for other contributors)

The seventh highest contributor to significant release (2.28E-07..6.0%) comes from PDS 10, Station Blackout with Power Recovery prior to Vessel failure but failure of all ECCS and Containment Safeguards. The predominant containment failure mode is described by CET 5, sequences 73 and 75, and radionuclide releases are again represented by source term categories STC 16 and 17. PDS 10 is dominated by a loss of offsite power initiating event with a failure of all DC power resulting from common cause battery failures. Thus although AC power from the grid is recovered after 1 hour, the breakers in the 6.9 kv and 480Vac buses require DC power and no credit has been taken for manual alignment to feed the plant loads.

Other individual plant damage states contribute less than than 5% of the total Type I and II releases.

The only other plant damage state that needs discussing here is
PDS 47, Interfacing Systems LOCA. Although the contribution to containment failure leading to Type I and II releases is low (2.68E-08...0.7%), it results in the largest release magnitude (STC 24) (ie. 17.5 x WASH 1400 PWR-4 release category). There is a direct path to atmosphere with no credit taken for submerged release points or any radionuclide deposition in the Primary Auxiliary Building due to the design of that building. The analysis of the frequency of interfacing sysytems LOCA follows the NUREG/CR 5102 approach. The RHR suction piping is the dominant interfacing LOCA pathway path. Credit is taken for the IP2 design in which the transition from high pressure to low pressure piping occurs inside containment and there is a high likelihood that, in the event of valve ruptures leading to an overpressure of the low pressure piping, failure may occur inside the containment boundary.

The containment failure attributes leading to each source release category are shown in Figure 3.4-1. The important contributors to each release type are discussed in section 3.4.1.2.

3.4.2.4 Vulnerability Conclusions

The conclusion of this evaluation is that there are no fundamental weaknesses or so called, "vulnerabilities", associated with the IP2 design or mode of operation.

This conclusion is drawn for two reasons:

First, application of the NUMARC 91-04 guidelines to the IP2 functional sequence groups suggests that their frequency/consequence are sufficiently low that only procedural or minor hardware changes should be further considered and only in the case of one sequence group. For other functional sequence groups, treatment in the plant's Severe Accident Managemment Guidelines (SAMG) or "No Specific Action" is recommended.

Second, we define the term vulnerability as components, systems or operator actions that contribute significantly to an unacceptably high level of risk. Based on draft safety goals and generally accepted industry practice, the following criteria can be established for use in evaluating the existence of vulnerabilities:

1) The mean core damage frequency substantially exceeds 1.0E-04 per year.

2) The mean frequency of large releases substantially exceeds 1.0E-06 per year, where a large release is defined as one for which the resulting mean fatalities are zero. Reference 3.4-6, indicates that this is the case for releases where the average Cs, Te and I release fractions are less than .08 to 0.1.

On both counts no vulnerability exists at IP-2. The mean IP2 core damage frequency is 3.13E-05 per year, well below 1.0E-04 per year. Based on Section 4.7, only the following source term categories exceed the criteria for large release at IP-2.

Source Term Category		Frequency (per year)
STC 2		2.14E-08
STC 3		1.69E-09
STC 4		1.00E-10
STC 5		8.45E-11
STC 6		3.21E-11
STC 7		1.64E-11
STC 8		1.54E-08
STC 9		1.62E-09
STC 19		4.89E-09
STC 20		4.90E-09
STC 21		1.68E-10
STC 24		2.67E-08
STC 26		3.73E-07
	Total	4.50E-07

The total large release frequency 4.5E-07 per year is also well below the screening criteria of 1.0E-06 per year.

That is not to conclude that enhanced risk insights have not been gained from this effort. As discussed in Section 6, we have and will continue to seek opportunities to incorporate the insights gained from this IPE and previous studies into our decision making process.

3.4.3 Decay Heat Removal Evaluation

The objectives of the Task Action Plan A-45 are to evaluate the adequacy of Decay Heat Removal (DHR) in existing light water nuclear power plants, and to assess the value of alternative measures for improving the overall reliability of the DHR function, if required. A program was developed by the NRC and case studies performed to investigate this issue. One of the studies was performed for a typical Westinghouse 3 Loop PWR (Ref. 3.4-7)

In order to understand the adequacy of the results of the IP-2 IPE with regard to resolution of this issue, it is approriate to compare the approach performed in the IPE with that used in Reference 3.4-7. The initial steps in assessing the adequacy of DHR in the A-45 program were to 1) characterize the units in terms of their physical parameters (ie. number and location of pumps, number of redundant emergency power suppplies, etc), and 2) develop a set of qualitative screening criteria against which the plant characteristics could be compared. This set of qualitative screening criteria was based upon a thorough review of guidance such as the Standard Review Plan, various Regulatory Guides, previous PRAs and topical studies. The intent was to establish a set of questions which would reveal potential deficiencies in DHR capabilities for both Design Basis and Beyond Design Basis events. This screening process resulted in a set of plants to be evaluated in the DHR study.

The analysis procedure used to perform the DHR study was a shortened PRA approach which considered only a limited number initiating events. The approach that has been used to perform the IP-2 IPE has been a comprehensive, plant specific level I/II PRA which considers a much greater number of initiating events and a full complement of front line and support systems. A comparison of initiating events is shown in Table 3.4-11 and of front line and support systems in Table 3.4-12. The scope of the IP-2 IPE meets the performance requirements for A-45 resolution and exceeds that of the NRC DHR studies.

The delineation of the accident sequences, systems analysis and quantification are fully described in References 3.4-1 and 3.4-2. The identification, ranking of accident sequences and the evaluation for potential vulnerabilities are described in Sections 3.4.1 and 3.4.2. The discussion below addresses the specific results pertaining to DHR systems and benefits from a review of insights provided in reference 3.4-7 and Generic letter 88-20, Appendix 5.

At IP-2 the DHR function is accomplished by the following systems:

- o For Large and Medium Loss of Coolant Accidents (LOCAs), decay heat is transferred from the core to the containment using high and/or low pressure injection pumps (ie. SIS pumps and RHR pumps). During recirculation, decay heat is removed from the core and the containment via the Recirculation System which can utilize one of two Recirculation pumps located inside containment or one of the two RHR pumps located in the Primary Auxiliary Building (PAB). In case the RCS pressure is high either the RHR or Recirculation pumps can feed the suction of the SI pumps. Recirculating water from the containment or recirculation sump passes through the RHR heat exchangers and transfers heat to the component cooling system and then to the Non Essential Service Water System to the Hudson River. The discharge of RHR pumps or the Recirculation Pumps can be routed to the RCS and/or to the containment spray rings. Heat may also be removed from the containment via five safety grade Containment Fan Coolers which transfer heat directly to the Essential Service Water Header to the Hudson River.

- o For transients and small break LOCAs, the Auxiliary Feedwater System (AFS) provides decay heat removal via the steam generators to atmosphere via the Atmospheric Steam Dump Valves, Safety Valves or main condenser Steam Dump Valves. Main Feedwater, which trips following most initiating transients, may also be recovered if the AFS is unavailable. In the event that AFS fails and Main Feedwater cannot be recovered, primary feed and bleed cooling (consisting of one of three SI pumps and two Pressurizer PORV trains) are utilized for successful decay heat removal.

The following features of the IP-2 systems enhance the reliability of decay heat removal, as follows:

- o The AFS system has three redundant pump trains, two motor driven and one turbine driven. The motor driven pumps each feed two steam generators, whereas the turbine driven pump feeds all four.

- o The AFS has a primary water supply from the CST and a secondary supply from the City Water Header

- o Following Station Blackout and subsequent battery depletion, the AFS turbine driven pump may be controlled manually and key plant parameters monitored using pneumantic instrumentation. This action is explictly directed by existing operating procedures.

- o The AFS Pump Room does not require forced room cooling due to the presence of a roll up door which directly accesses the yard and can be opened to allow adequate natural ventilation cooling. Opening of the roll up door is also proceduralized in EOP ECA 0.0 and the Alarm Response Procedure for SCF Window 4-4.

- o The EOPs (FR-H.1) provide explicit instructions for the restoration of AFS and to align the Main Feedwater/Condensate System, if necessary. No credit is taken in the current model for Main Feedwater/Condensate decay heat removal.

- o Initiation of Primary Feed and Bleed is also proceduralized in the EOPs (FR-H.1). Proper account of the limited time available for initiating this function at IP-2 (factoring in low shut off head of the SI pumps and PORV capacity to power ratio) has been taken in evaluating the reliability of the operator.

- o For large and medium LOCA or sequences requiring primary feed and bleed, the Containment Fan Coolers provide a redundant means of removing containment heat if the RHR heat exchangers or their associated support systems fail. The success criteria adopted for the fan coolers is 3 out of five which is conservative.

- o Two sets of redundant pumps (RHR and Recirculation) are provided for recirculating water from the Containment floor, through the RHR heat exchangers and back to the RCS or to the containment spray ring. This arrangement serves: first, to provide additional hardware reliability, and second, to provide a mechanism for recovery, in some cases, if the operator were unable to initiate timely switchover upon RWST depletion, as discussed in section 3.3.1. This latter benefit is not accounted for in the current analysis.

Approximately 48% of the calculated core damage frequency involves sequences which involve loss of Auxiliary Feedwater. Approximately 32% involve failure of Primary Bleed. (Since AFS and Primary Bleed Sequences often appear in the same sequence, their importance is not additive). A further 18% and 6% involve failure of low and high pressure recirculation, respectively. Thus a significant percentage of the calculated core damage frequency does involve failure of the DHR functions.

However, the overall CDF at IP2 is relatively low, and thus the absolute frequency contribution is not significantly different than at other plants. For example, at the Seabrook and Surry plants (Refs. 3.4-8 and 3.4-9), the reported core damage frequencies are 1.1E-4 per year (includes external events) and 7.5E-5 per year (internal events only) respectively. The importance of Auxiliary Feedwater at both of these plants is approximately 15%, resulting in absolute contributions to CDF of 1.65E-5 for Seabrook and 1.1E-5 for Surry. The contribution of Auxiliary Feedwater at IP2 is 3.13E-5 x .48 = 1.5E-5 per year. It should also be noted that this contribution includes failures of AFW under degraded power support conditions as well as full power support conditions. As mentioned above, the importance of primary bleed to decay heat removal is linked, in almost all cases to recovery following failure of auxiliary feedwater. Consideration of decay heat removal in the context of the CDF contribution of loss of secondary side heat sink therefore already encompasses any loss of primary bleed contribution. With respect to Recirculation decay heat removal, the IP2 contribution is 7.5E-6 compared to 5.0E-6 for Seabrook and 5.6E-6 for Surry.

The contributions of individual components to Auxiliary Feedwater System and Primary Bleed failures are discussed in section 3.4.2.1.1. Significant contributors are common cause failures of the motor driven AFS pumps in combination with a failure of the AFS turbine driven pump to run during its mission. A sensitivity analysis performed using a more realistic mission time for the AFS turbine driven pump (8 hours versus 24 hours) demonstrated a 40% reduction in the calculated AFS unavailability compared with the base case and a corresponding 14% reduction in the overall CDF (see section 3.4.1.4.2). The most significant contribution to Recirculation failure is operator error.

In summary, this Individual Plant Examination has shown that the likelihood and nature of DHR related events are well understood and the IPE did not reveal any vulnerabilities associated with the design, the components or operating practices of the DHR function. Furthermore, the inclusion of specific conservatisms in the analysis, as discussed in Section 3.4.2.1.1 and 3.4.1.4.2, in the areas of main feedwater/condensate recovery, normal PORV block valve alignment, and unaccounted for protection against hardware damage during the switchover to recirculation further support this position.

3.4.4 USI and GSI Evaluation

This report addresses one unresolved safety issue with respect to internal initiating events:

"USI A-45, Decay Heat Removal" which is addressed in the previous section. The conclusion from that evaluation is that there are no vulnerabilities in this area.

No other issues have been identified at this time that are resolved via this IPE report. However it is expected that the risk analysis for IP-2 may be used in the future to directly resolve or assist in resolving generic issues.

3.4.5 References for Section 3.4

3.4-1. Generic Letter 88-20 "IPE for Severe Accident Vulnerabilities", USNRC, November 23, 1988

3.4-2. NUREG 1335 "Individual Plant Examination Submittal Guidance", (final)

3.4-3. NUMARC 91-04 "Severe Accident Issue Closure Guidelines", January, 1992

3.4-4. NSAC-166 "Losses of Offsite Power and Station Blackout at US Nuclear Power Plants", April 1981

3.4-5. NUREG-1032 " Evaluation of Station Blackout at US Nuclear Power Plants", June 1988

3.4-6. G.D. Kaiser. "The Implications of Source Term Research for Ex Plant Consequence Modeling" Presented to the ANS Topical Meeting on Fission Product behavior and Source Term Research, Snowbird, Utah, July 15-19, 1984

3.4-7. NUREG 4762 "Shut Down Decay Heat Removal Analysis of a Westinghouse 3 - loop PWR", March 1987

3.4-8. New Hampshire Yankee Supplimentary Response to Generic Letter 88-20, March 14, 1991

3.4-9. "PRA for Surry Nuclear Power Plant 1 and 2", Virginia Power, August 1991

TABLES FOR SECTION 3

TABLE 3.1-1
Large LOCA Success Criteria

Success Path No.	Reactivity Control	Core Heat Removal Early	Core Heat Removal Late	Secondary Heat Removal	RCS Integrity	Containment Heat Removal
1	No Automatic Scram Required But Borated Water Injection Required for Long-Term Subcriticality	1/2 RHR (a) AND 3/3 Accumu-lators in Intact Loops	1/2 RHR- (b) OR 1/2 Recirc.- Pumps in Low Pressure Recirculation Mode AND Switchover to Hot Leg Recirc. in 24 Hours (c)	Not Required	Lost as Result of Initiator	3/5 CFC (Note 4) or CS

Notes:

1. IPPSS Success Criteria are unchanged with the exception of containment spray (see note 4).

2. All PRAs, including NUREG-1150 of Surry and Zion, consider 1/2 Low Head Injection Pumps in conjunction with all accumulators in the intact loops to constitute success in the injection phase. The assumption on the required number of accumulators is likely to be conservative, in that even none may be required to meet the acceptance criteria. This assumption does not need to be changed with Large LOCA being an insignificant contributor to core damage frequency.

3. In the recirculation phase, 1/2 RHR pump trains are considered success in all PRAs. The success criterion of the Recirculation System is obtained by deduction.

4. Recirculation of cooled sump water through the vessel in the absence of fan coolers or sprays, may be inadequate to prevent long term containment overpressurization. This is an issue for a large cold leg break since the injection water may bypass the core with minimal heat tranfer. In this case the majority of the decay enters the containment as steam and calculations indicate that natural condensation at the containment and pool surfaces may not be adequate to tranfer the heat to recirculating water. Therefore containment heat removal may require fan coolers or sprays in the long term to prevent long term overpressurization. 2/5 Containment Fan Coolers can provide adequate containment heat removal capacity. IPPSS used 3/5 CFC trains, which is conservative but is retained in this analysis.

References used in developing the Large LOCA Success Criteria:

(a) NUREG/CR-4550, Vol. 3, Rev. 1, Part 1 (Surry, Ref. 3.1-10), NUREG/CR-4550, Vol. 7, Rev. 1 (Zion Ref. 3.1-11)
(b) IP2 FSAR Ch 14 (Ref. 3.1-17)
(c) WCAP-9691 (Ref. 3.1-18)
(d) IP-2 MAAP Analyses and hand calculations

TABLE 3.1-2
Medium LOCA Success Criteria

Success Path No.	Reactivity Control	Core Heat Removal Early	Core Heat Removal Late	Secondary Heat Removal	RCS Integrity	Containment Heat Removal
1	RPS	1/3 HPI Pump AND 3/3 Accum-ulators in Intact Loops	1/3 HPI Pumps AND 1/2 RHR- OR 1/2 Recirc.-Pumps in Recirc. Mode	Not Required	Lost as Result of Initiator	3/5 CFC
2	RPS	1/3 HPI Pumps (See Notes)	1/2 RHR Pumps OR 1/2 Recirc Pumps in recirc mode	1 AFW Pump **AND** 1 SG ARV	Same	Same
3	RPS	1/2 RHR Pumps (b,) AND 3/4 Accum-ulators	1/2 RHR- OR 1/2 Recirc.-Pumps in Recirculation	Steam Dump Through 3 SG ARV **AND** 2 AFW MDPs OR 1 AFW TDP	Same	Same

Notes: See next page

References:

(a) WCAP-9601 (Ref. 3.1-19)
(b) WCAP-9754 (Ref. 3.1-20)
(c) IP-2 MAAP Analysis

TABLE 3.1-2
Medium LOCA Success Criteria
(continued)

Notes:

1. A LOCA in an injection loop may fail HPI from one pump, and two HPI pumps may be required depending on the location of the break. This has been analyzed and shown to be a negligible contribution to HP failure

2. Success path 3 is based on a combination of WCAP-9754 and IP2-specific MAAP analysis. The WCAP shows that core damage will be prevented after core exit thermo-couple reading of 1200 °F is reached (with failure of HPI and secondary heat removal only through SG safety valves) using any one of several methods. One such method is to use the maximum secondary steam dump capacity and AFW flow, which will cause rapid depressurization of the primary system and allow the accumulators -(which are not strictly required for success) and RHR pumps to inject.

3. Note that each motor driven AFW pump is aligned to two SG, while the turbine driven pump (TDAFWP) is aligned to all four SGs.

4. Containment heat removal is satisfied with core heat removal. However, if injection and recirculation are successful with failure of RHR heat exchangers, because all decay heat can be removed through the break, an additional success path will exist by the use of the safety grade Containment Fan Coolers (2/5). IPPSS used 3/5 CFC trains, which is conservative but retained for this analysis.

TABLE 3.1-3
Small LOCA Success Criteria

Success Path No.	Reactivity Control	Core Heat Removal Early	Core Heat Removal Late	Secondary Heat Removal	RCS Integrity	Containment Heat Removal
1	RPS	1/3 HPI Pumps	1/3 HPI Pumps **AND** 1/2 RHR- **OR** 1/2 Recirc.-Pumps in Recirc. Mode	1/3 AFW Pumps to 1 SG	Lost as Result of Initiator	3/5 CFC (Note 2)
2	RPS	1/3 HPI Pumps	1/2 RHR- **OR** 1/2 Recirc.-Pumps in Recirculation	Steam Dump Through 1 SG ARV **AND** 1 AFW Pump	Same	Same
3	RPS	1/3 HPI Pumps **AND** 2 PORVs	Same	Not Required	Same	Same
4	RPS	1/2 RHR Pumps) AND 3/4 Accumulators	1/2 RHR **OR** 1/2 Recirc. Pumps in Recirculation Mode	Steam Dump Through 3 SG ARV **AND** 1 AFW TD Pump or 2 AFW MD pump	Same	Same

Note:
1. WCAP-9754 uses full accumulator injection in its analysis of 1 inch break. Accumulators are not required for success.
2. Containment heat removal is satisfied with core heat removal. However, if injection and recirculation are successful with failure of RHR heat exchangers, because all decay heat can be removed through the break, an additional success path will exist by the use of the safety grade Containment Fan Coolers (2/5). IPPSS used 3/5 CFC trains, which is conservative and was retained for this analysis.
3. Note that each motor driven AFW pump is aligned to two SG, while the turbine driven pump (TDAFWP) is aligned to all four SGs.
4. LOCA on an injection loop may fail HPI from one pump, and two HPI pumps may be required depending on the location of the break. However, this requirement for two pumps was analyzed and found not to be a significant contribution to the unavailability of high pressure injection.

References:

(a) WCAP-9601 (Ref. 3.1-19)
(b) WCAP-9744 (Ref. 3.1-20)
(c) WCAP-9754 (Ref. 3.1-21)
(d) MAAP Analysis
(e) WCAP 9615 (Ref. 3.1-13)

TABLE 3.1-4
Transient Success Criteria

Success Path No.	Reactivity Control	Core Heat Removal Early	Core Heat Removal Late	Secondary Heat Removal	RCS Integrity	Containment Heat Removal
1	RPS Scram	RCS - Natural Circ. (Note 1)		1/3 AFW Pumps to 1 SG	RCS PORV Closure (Note 4)	3/5 CFC Note 5
2	RPS	1/3 HPI Pumps **AND** 2 PORVs	1/3 HPI **AND** 1/2 RHR **OR** 1/2 Recirc Pumps in Recirc Mode	Not Required	Same	Same

Notes:

1. Bleed & Feed operation fails RCS Integrity through continued RCS PORV use.

2. For Transients, RCS depressurization before recirculation is not certain, so only high head recirculation is modeled.

3. A steamline break with subsequent failure of HPI is not considered to be a core damage sequence without additional failures. This is based on the reasoning that the steamline break analysis used in the FSAR incorporate very conservative licensing type assumptions (e.g., most reactive control rod bank stuck, etc.) for calculation of the resulting DNBR. In practice, a steamline break followed by the failure of HPI is expected to meet the PRA acceptance criteria (a very small percentage of fuel rods may exceed the acceptance criterion maximum cladding temperature limit of 2200 °F, if any at all).

4. In the event of a stuck open relief valve with failure of the block valve, the sequence is transferred to the Small LOCA event tree.

5. Containment heat removal is satisfied with core heat removal. However, if injection and recirculation are successful with failure of RHR heat exchangers, because all decay heat can be removed through the break, an additional success path will exist by the use of the safety grade Containment Fan Coolers (2/5). IPPSS used 3/5 CFC trains, which is conservative but retained for this analysis.

References:

a. WCAP-9691 (Ref. 3.1-18)
b. WCAP-9744 (Ref. 3.1-21)
c. WCAP-9615 (Ref. 3.1-13)

TABLE 3.1-5
Steam Generator Tube Rupture Success Criteria

Success Path No.	Reactivity Control	Core Heat Removal Early	Core Heat Removal Late	Secondary Heat Removal	RCS Integrity	Containment Heat Removal
1	RPS	RCS Natural Circulation, (Note 2) **AND** 1/2 PORVs		1/3 AFW pumps **AND** 3 SG ARVs	Achieved by cooldown and depress of RCS isolation of affected SG early	3/5 CFC Note 5
2	RPS	1/3 HPI Pumps (Note 3)	1/2 RHR Pumps in SD Cooling Mode (see note 6)	1/3 AFW Pumps **AND** 1 SG ARV	Containment Bypassed (Core Intact)	Same
3	RPS	1/3 HPI Pumps **AND** 2/2 PORVs or Blowdown of Ruptured SG using 1 SG ARV	Recirc through 1/3 HP and 1/2 RHR/Recirc Pumps **OR** 1/2 RHR pumps SD cooling mode (see note 6)	Not Required	Lost as a Result of Induced LOCA	Same
4	RPS	1/2 RHR Pumps (Note 0)	1/2 RHR- in SD cooling mode (see note 6)	Steam Dump Through 3 SG ARVs AND 2/3 AFW Pumps	Containment Bypassed (Core Intact)	Same

Notes: 0. The four success paths identified here correspond to the six IPPSS success paths discussed in the text as described below. The four success path breakdown is deemed more appropriate in that it utilizes distinct system combinations in each path with specific criteria relating to the success in rapid cooldown and depressurization, and whether SG isolation succeeds and there are no stuck open SG safety relief valves (SORV). The IPPSS model does not explicitly account for the potential for a SG SORV.(Continued on Next Page)

TABLE 3.1-5
Steam Generator Tube Rupture Success Criteria
(continued)

Notes:

1. The success criteria for SGTR initiator are a mixture of those for transients and LOCAs in that once the leakage of primary coolant into the affected steam generator is terminated, the requirements for subsequent system operations are the same as transients. On the other hand, if the primary to secondary leakage is not terminated,the situation will resemble a small LOCA with the difference that the lost inventory cannot be recirculated through the sump and the containment is bypassed. The inability to recirculate is not significant, however, since the amount of leakage is relatively small (RWST inventory will last many hours). Thus in the first success path, cooldown and depressurization of the primary system is performed rapidly enough so that primary system pressure drops below that of the affected SG before core uncovers and before the SG fills up resulting in a potential for a stuck open SG safety valve (SORV). The second success path assumes that a SORV does occur. In that case, stable end sate can only be achieved by cooling and depressurizing the RCS to atmospheric pressure and using RHR system in its normal decay heat removal function. Success path 3 is the normal feed and bleed option, which terminates RCS leakage into the secondary system. Success path 4 is the same as core cooling recovery in small LOCA.

2. With Successful Ruptured SG Isolation and No Stuck Open Safety Relief Valve.

3. With failure of Ruptured SG Isolation and/or Stuck Open Safety Relief Valve.

4. With Successful Ruptured SG Isolation and Stuck Open Safety Relief Valve.

5. Containment heat removal is satisfied with core heat removal. However, if injection and recirculation are successful with failure of RHR heat exchangers, because all decay heat can be removed through the break, an additional success path will exist by the use of the safety grade Containment Fan Coolers (2/5). IPPSS used 3/5 CFC trains, which is conservative and was retained for this analysis. In the event tree modeling containment heat removal is not an issue since core heat is removed via secondary side or RHR shutdown cooling

6. If the ruptured SG cannot be isolated, it is assumed that make up to the RWST is required for successful accident mitigation.

References:

(a) WCAP-9744 (Ref. 3.1-21)
(b) WCAP-9754 (Ref. 3.1-20)
(c) IP-2 MAAP Analysis

TABLE 3.1-6
ATWS Success Criteria

Success Path No. Removal	Reactivity Control	Core Heat Removal Early	Core Heat Removal Late	Secondary Heat Removal	RCS Integrity	Containment Heat
1	Reactor Power < 40% (a)					
	Manual Rod Insertion **OR** Deenergize MG Set **OR** Emergency Boration	RCS		1 of 3 AFW Pumps (Note 1)	PORV Reclosure	3/5 CFC Note 2
2	Reactor Power > 40% (a)					
	Manual Rod Insertion **OR** Deenergize MG Set **OR** Emergency Boration	Same		2 MD AFW **OR** 1 TD AFW Pump(s) (See Notes)	AMSAC/ Turbine Trip **AND** Adequate Pressure Relief	Same

Note:

1. No credit is taken for potential availability of the Main Feedwater System.

2. Containment heat removal is satisfied with core heat removal. However, if injection and recirculation are successful with failure of RHR heat exchangers, because all decay heat can be removed through the break, an additional success path will exist by the use of the safety grade Containment Fan Coolers (2/5). IPPSS used 3/5 CFC trains, which is conservative and was retained for this analysis.

References: (a) WCAP-11993 (Ref. 3.1-2)

TABLE 3.1-7
Split Fraction Logic For Large LOCA Event Tree

Split Fraction	Split Fraction Logic
	LOSP:= OG=F + Y5=F * Z6=F
RW1	1
LPF	RW=F +BUS6A * (BUS3A + BUS5A) +BUS3A * BUS5A * BUS6A +TRAINA * BUS6A +TRAINB * (BUS3A + BUS5A) +BUS5A * BUS6A +TRAINA * TRAINB
LP4	BUS6A + BUS3A * BUS5A + TRAINA + TRAINB
LP3	BUS3A
LP2	BUS5A
LP1	1
AS1	1
FCF	BUS5A * (BUS2A + BUS3A + BUS6A) +BUS2A * BUS3A * BUS6A +TRAINA * TRAINB +SA=F
FC6	(BUS2A * BUS3A) + (BUS5A + BUS2A * BUS6A) + (BUS3A* BUS6A)
FC5	BUS6A + BUS3A + BUS2A
FC4	1
LRF	RW=F + LP=F + BUS6A * BUS3A * BUS5A + CC=F * (BUS6A +BUS5A)
LRB	CC=F * BUS3A
LRA	CC=F

TABLE 3.1-7
Split Fraction Logic For Large LOCA Event Tree
(continued)

Split Fraction	Split Fraction Logic
LR3	BUS3A + BUS5A
LR2	BUS5A * BUS3A + BUS6A
LR1	1
RHF	BUS5A * BUS6A + CC=F
RH2	BUS5A + BUS6A
RH1	1
RCF	RW=F + AS=F + SB=F + CC=F + BUS5A * BUS6A
RC3	BUS2A
RC2	BUS5A + BUS6A
RC1	1
CSF	RW=F + LP=S * LR=F + LP=F * (TRAINA * TRAINB + BUS5A *(BUS6A + TRAINB) + BUS6A * TRAINA) + LP=S * LR=S * BUS6A*BUS5A
CS2	RW=S * LP=F * (BUS5A + BUS6A)
CS1	RW=S * LP=F
CS5	LR=S * (BUS5A + BUS6A)
CS4	LR=S

TABLE 3.1-8
Binning Logic for Large LOCA Event Tree

PDS	Binning Logic
S	RW=S * LP=S * AS=S * FC=S * LR=S * RH=B * RC=S * CS=B + RW=S * LP=S * AS=S * FC=F * LR=S * RH=S * RC=S * CS=S
PDS35	CS=S * ((FC=S + RH=S) * AS=F * LP=S * LR=S + RC=F)
PDS36	CS=S * FC=S * -(LR=S)
PDS37	CS=S * FC=F * (RH=F + RH=B)
PDS38	-CS=S * FC=S * (LP=S * LR=S * RW=S + RC=F)
PDS39	-CS=S * FC=S * (LP=S + -AS=F) * -LR=S
PDS40	-CS=S * FC=F * (RH=F + RH=B) + RW=F * AS=F + -CS=S * -LP=S * AS=F
LLMELT	1

TABLE 3.1-9
Split Fraction Logic for Medium LOCA Event Tree

Split Fraction	Split Fraction Logic
	CCF:=(A5=F + SA=F * -(Y5=S * D1=S)) * (A2=F + SA=F *-(W2=S *
	X3=S * D1=S * D2=S)) * (A6=F + SA=F * -(Z6=S *D2=S)) + SB=F
	LOSP:= OG=F + Y5=F * Z6=F
RW1	SIEVENT
HPF	RW=F + (BUS5A * TRAINA + BUS6A * TRAINA) + (BUS5A * BUS6A)+ (BUS5A * BUS6A) + (BUS6A * BUS2A) + (TRAINA * TRAINB)
HP5	(TRAINA + TRAINB + BUS5A + BUS6A) * BUS2A
HPD	BUS5A + BUS6A + TRAINA + TRAINB
HP4	BUS2A
HP3	1
ASF	RW=F
AS1	1
L1F	(TRAINA * TRAINB) + (BUS3A * BUS6A * D1=F * HP=S) +(BUS3A + BUS6A) * D1=F * HP=F
L16	HP=F * BUS3A * BUS6A
L15	HP=F * (BUS3A + BUS6A)
L14	HP=F
L13	BUS3A * BUS6A * HP=S
L12	BUS3A + BUS6A * HP=S
L11	1
DZF	D3=F * BUS3A
DZ2	1
Y1F	BUS3A * D3=F + L1=F
Y11	1
LPF	RW=F + BUS6A * (BUS3A + BUS5A) + BUS5A * BUS3A * BUS6A +(BUS6A * TRAINA) + (BUS3A + BUS5A) * TRAINB + TRAINA *TRAINB + BUS5A * BUS6A

TABLE 3.1-9
Split Fraction Logic for Medium LOCA Event Tree
(continued)

Split Fraction	Split Fraction Logic
LP4	BUS6A + BUS3A * BUS5A + TRAINA + TRAINB
LP3	BUS3A
LP2	BUS5A
LP1	1
HRF	BUS3A * BUS5A * BUS6A
HR8	BUS6A * BUS3A
HR7	BUS5A * BUS3A
HR6	CC=F * BUS2A * BUS3A * BUS5A
HR4	BUS3A + BUS5A + BUS6A + BUS2A
HR3	(BUS6A + BUS5A * BUS3A) * (BUS2A + BUS3A) * (BUS6A + BUS2A * BUS3A + BUS5A)
HR2	(BUS5A + BUS3A) * (BUS5A + BUS2A * BUS3A + BUS2A * BUS6A +BUS3A * BUS6A) * (BUS6A + BUS2A * BUS3A + BUS5A)
HR1	1
DPF	BUS3A * D3=F + L1=F
DP1	1
LIF	RW=F + BUS6A * (BUS3A + BUS5A) + BUS5A *BUS3A * BUS6A +(BUS6A * TRAINA) + (BUS3A + BUS5A) * TRAINB + TRAINA *TRAINB + BUS5A * BUS6A
LI4	BUS6A + BUS3A * BUS5A + TRAINA + TRAINB
LI3	BUS3A
LI2	BUS5A
LI1	1
FCF	SA=F + BUS5A * (BUS2A + BUS3A + BUS6A) +(BUS2A * BUS3A * BUS6A) + (TRAINA + TRAINB)
FC6	BUS5A + BUS2A * BUS3A + BUS2A * BUS6A
FC5	BUS6A + BUS3A + BUS2A
FC4	1
RH1	1

TABLE 3.1-9
Split Fraction Logic for Medium LOCA Event Tree
(continued)

Split Fraction	Split Fraction Logic
CSF	RW=F + (LP=S + LI=S + HP=S) * (LR=B + LR=F) * (HR=F + HR=B) + HP=F * (LP=F + LI=F) * (TRAINA * TRAINB + BUS5A * (BUS6A + TRAINB) +BUS6A * TRAINA) + (HR=S + LR=S) * BUS5A * BUS6A
CS2	RW=S * HP=F * (LP=F + LI=F) * (BUS5A + BUS6A + TRAINA +TRAINB)
CS1	RW=S * CS1 + HP=F * (LP=F + LI=F)
CS5	(HR=S + LR=S) * (BUS5A + BUS6A)
CS4	HR=S + LR=S
LRF	CC=F * (BUS5A + BUS6A) + BUS6A * BUS3A * BUS5A
LRD	CC=F * BUS3A
LRC	CC=F
LR8	BUS3A + BUS5A
LR7	BUS6A + BUS3A * BUS5A
LR6	1
RHF	BUS5A * BUS6A + CCF
RH2	BUS5A + BUS6A
RH1	1

TABLE 3.1-10
Binning Logic for Medium LOCA Event Tree

PDS	Binning Logic
S	RW=S*HP=S*AS=S*L1=S*DZ=S*FC=S*LR=S+ RW=S*HP=S*AS=S*L1=S*DZ=S*FC=F*LR=S*RH=S+ RW=S*HP=S*AS=S*L1=S*DZ=F*Y1=B*LP=B*FC=S*HR=S*DP=B*LI=B*LR=B*RH=B*CS=B+ RW=S*HP=S*AS=S*L1=S*DZ=F*Y1=B*LP=B*FC=F*HR=S*DP=B*LI=B*LR=B*RH=S*CS=B+ RW=S*HP=S*AS=S*L1=F*Y1=B*LP=B*FC=S*HR=S*DP=B*LI=B*LR=B*RH=B*CS=B+ RW=S*HP=S*AS=S*L1=F*Y1=B*LP=B*FC=F*HR=S*DP=B*LI=B*LR=B*RH=S*CS=B+ RW=S*HP=F*AS=S*L1=S*Y1=S*LP=S*FC=S*HR=B*DP=B*LI=B*LR=S*RH=B*CS=B+ RW=S*HP=F*AS=S*L1=S*Y1=S*LP=S*FC=F*HR=B*DP=B*LI=B*LR=S*RH=S*CS=B
PDS41	CS=S * (FC=S + RH=S) * (LR=S + HR=S)
PDS42	CS=S * FC=S * -(HR=S + LR=S)
PDS43	CS=S * FC=F * (RH=F + RH=B)
PDS44	-CS=S * (FC=S + RH=S) *(HR=S + LR=S)
PDS45	-CS=S * FC=S * (LP=S + LI=S + HP=S + -AS=F) * -(HR=S + LR=S)
PDS46	-CS=S * FC=F * (RH=F + RH=B) + RW=F * AS=F +-CS=S * -(HP=S + LP=S + LI=S) * AS=F
MLMELT	1
	CCF:= (A5=F + SA=F * -(Y5=S * D1=S)) * (A3=F + SA=F *-(W2=S * X3=S * D1=S * D2=S)) * (A2=F + SA=F * -(Y5=S *D1=S)) * (A6=F + SA=F* -(Z6=S * D2=F)) + SB=F
	LOSP:= OG=F + Y5=F * Z6=F

TABLE 3.1-11
Split Fraction Logic for Small LOCA Event Tree

Split Fraction	Split Fraction
RW2	SIEVENT
HPF	RW=F + (BUS5A * BUS2A * TRAINB + BUS6A * BUS2A * TRAINA) +BUS5A * BUS6A * BUS2A +(TRAINA * TRAINB)
HP5	(TRAINA + TRAINB + BUS5A + BUS6A) * BUS2A
HPD	BUS5A + BUS6A + TRAINA + TRAINB
HP4	BUS2A
HP3	1
L1F	TRAINA * TRAINB + BUS3A * BUS6A * D1=F
L13	BUS3A * BUS6A
L12	BUS3A + BUS6A
L11	1
O1F	D1=F + D2=F + BUS5A + BUS6A
O11	1
DZF	D3=F * BUS3A
DZ1	1
Y1F	L1=F + D3=F * BUS3A
Y11	1
AS1	1

TABLE 3.1-11
Split Fraction Logic for Small LOCA Event Tree
(continued)

Split Fraction	Split Fraction
L1F	RW=F + BUS6A * (BUS3A +BUS5A)+BUS5A * BUS3A * BUS6A + (BUS6A*TRAINA) + (BUS3A * BUS5A) *TRAINA + TRAINA * TRAINB + BUS5A * BUS6A
LP4	BUS6A + BUS3A*BUS5A + TRAINA + TRAINB
LP3	BUS3A
LP2	BUS5A
LP1	1
HRB	HP=S * (BUS2A + BUS3A)
HRA	1
LI3	BUS3A
LI2	BUS5A
LI1	1
DPF	L1=F + BUS3A * D3=F
DP1	1
LIF	RW=F + BUS6A*(BUS3A+BUS5A) + BUS5A*BUS3A*BUS6A + (BUS6A*TRAINA) + (BUS3A+BUS5A)*TRAINB + TRAINA*TRAINB + BUS5A*BUS6A
LI4	BUS6A + BUS3A*BUS5A + TRAINA + TRAINB
FCF	SA=F + BUS5A * (BUS2A + BUS3A + BUS6A) + BUS2A * BUS3A * BUS6A +TRAINA * TRAINB
FC6	BUS5A + BUS2A * BUS3A + BUS2A * BUS6A + BUS3A* BUS6A
FC5	BUS2A + BUS3A + BUS6A
FC4	1
HRG	HP=S * CC=F
HRD	HP=S * BUS5A * BUS2A
HRC	HP=S * BUS2A * BUS3A
HRF	BUS5A * BUS6A
HRI	HP=S * BUS5A
HRH	HP=S * (BUS6A + BUS2A)

TABLE 3.1-11
Split Fraction Logic for Small LOCA Event Tree
(continued)

Split Fraction	Split Fraction
LRF	CC=F * (BUS5A + BUS6A) + BUS6A*BUS3A*BUS5A
LRD	CC=F * BUS 3A
LRC	CC=F
LR8	BUS3A+BUS5A
LR7	BUS6A + BUS3A*BUS5A
LR6	1
RHF	BUS5A * BUS6A + CCF
RH2	BUS5A + BUS6A
RH1	1

TABLE 3.1-12
Binning Logic for Small LOCA Event Tree

PDS	Binning Logic
S	RW=S*HP=S*L1=S*O1=B*DZ=S*FC=S*LR=S+ RW=S*HP=S*L1=S*O1=B*DZ=S*FC=F*LR=S*RH=S+ RW=S*HP=S*L1=S*O1=B*DZ=F*Y1=B*AS=B*LP=B*FC=S*HR=S*DP=B*LI=B*LR=B*RH=B*CS=B+ RW=S*HP=S*L1=S*O1=B*DZ=F*Y1=B*AS=B*LP=B*FC=F*HR=S*DP=B*LI=B*LR=B*RH=S*CS=B+ RW=S*HP=S*L1=F*O1=S*Y1=B*AS=B*LP=B*FC=S*HR=S*DP=B*LI=B*LR=B*RH=B*CS=B+ RW=S*HP=S*L1=F*O1=S*Y1=B*AS=B*LP=B*FC=F*HR=S*DP=B*LI=B*LR=B*RH=S*CS=B+ RW=S*HP=F*L1=S*Y1=S*AS=S*LP=S*FC=F*LR=S*RH=S+ RW=S*HP=F*L1=S*O1=B*Y1=S*AS=S*LP=S*FC=S*HR=B*DP=B*LI=B*LR=S*RH=B*CS=B
PDS41	CS=S * (FC=S + RH=S) * (LR=S + HR=S)
PDS42	CS=S * FC=S * -(LR=S + HR=S)
PDS43	CS=S * FC=F * (RH=F + RH=B)
PDS44	-CS=S * (FC=S + RH=S) * (HR=S + LR=S)
PDS45	-CS=S * FC=S * -(HR=S + LR=S)
PDS46	-CS=S * FC=F * (RH=F + RH=B) + (RW=F * AS=F) +-CS=S * -(HP=S + -LP=S + -LI=S) * AS=F
SLMELT	1
L12	BUS3A + BUS6A
L11	1
RW2	1
HPF	RW=F + BUS5A * BUS2A * TRAINB + BUS6A * BUS2A * TRAINA+ BUS5A * BUS6A * BUS2A
HP5	(TRAINA + TRAINB + BUS5A + BUS6A) * BUS2A
HPD	TRAINA + TRAINB + BUS5A + BUS6A

TABLE 3.1-13
Split Fraction Logic for General Transient Event

Split Fraction	Split Fraction Logic
	LOSP:= OG=F + Y5=F * Z6=F
PV3	(INIT=MSLBIC + INIT=MSLBOC + INIT=LOFW + INIT=MSIVC + INIT=CPI + INIT= RXTRIP +INIT=LOCCW + INIT=LODC21 + INIT=LODC22 + INIT=TTRIP + INIT=LOSW + INIT= L0692 + INIT=L0693) * BUS5A * BUS6A
PV2	(INIT=LOFW + INIT = L0692 + INIT=L0693 + INIT=MSIVC + INIT=CPI + INIT=RXTRIP + INIT=LOCCW + INIT=LODC21 + INIT=LODC22 + INIT=TTRIP + INIT=LOSW + INIT=MSLBIC + INIT=MSLBOC) * (BUS5A + BUS6A)
PV1	INIT=LOFW + INIT=MSIVC + INIT=CPI + INIT=RXTRIP +INIT=LOCCW + INIT=LODC21 + INIT=LODC22 + INIT=TTRIP +INIT=LOSW + INIT= MSLBOC + INIT=MSLBIC + INIT=L0692 +INIT=L0693
PV6	INIT=LOPF * BUS5A * BUS6A
PV5	INIT=LOPF * (BUS5A + BUS6A)
PV4	INIT=LOPF
PV7	INIT=TTRIP + INIT=LOSW
LSF	CC=F * BUS3A * BUS5A * BUS6A
LS3	CC=F * (BUS5A * BUS3A + BUS5A * BUS6A + BUS3A * BUS6A)
LS2	CC=F * (BUS5A + BUS3A + BUS6A)
LS1	1
TR1	INIT=SLBIC
TR2	1
L1F	BUS3A * BUS6A * D1=F + TRAINA * TRAINB
L13	BUS3A * BUS6A
HP4	BUS2A

TABLE 3.1-13
Split Fraction Logic for General Transient Event
(continued)

Split Fraction	Split Fraction Logic
HP3	1
01F	BUS5A + BUS6A + D1=F + D2=F
011	1
FCF	BUS5A * (BUS2A + BUS3A) + BUS2A * BUS3A * BUS5A +BUS2A * BUS3A * BUS6A +TRAINA * TRAINB +SA=F
FC6	(BUS5A + BUS2A * BUS3A + BUS2A * BUS6A + BUS3A *BUS6A)
FC5	(BUS2A + BUS3A + BUS6A)
FC4	1
HRF	BUS5A * BUS6A
HRI	BUS5A
HRH	(BUS6A + BUS2A)
HRG	CC=F
HRD	(BUS5A * BUS2A)
HRC	(BUS3A * BUS2A)
HRB	(BUS2A + BUS3A)
HRA	1
DPF	L1=F + D3=F * BUS3A
DP1	1
LIF	TRAINA * TRAINB + BUS3A * BUS6A * D1=F
LI3	BUS3A * BUS6A
LI2	BUS3A + BUS6A
LI1	1
CS1	RW=S * -HP=S * -LI=S
CS5	(HR=S + LR=S) * (BUS5A + BUS6A)
CS4	HR=S + LR=S

TABLE 3.1-13
Split Fraction Logic for General Transient Event
(continued)

Split Fraction	Split Fraction Logic
LRF	BUS5A * BUS6A * LI=B + BUS5A * BUS6A * BUS3A * LI=S
LRD	CC=F * BUS3A
LRC	CC=F
LR8	BUS3A + BUS5A
LR7	BUS6A + BUS2A * BUS5A
LR6	1
RHF	BUS5A * BUS6A
RH2	BUS5A + BUS6A
RH1	1
CSF	RW=F + (LI=S + HP=S) * (LR=B + LR=F) * (HR=F + HR=B) +-(LI=S * HP=S) *(TRAINA * TRAINB +BUS5A * (BUS6A + TRAINB) +BUS6A * TRAINA) + (HR=S + LR=S) * BUS5A * BUS6A
CS2	RW=S * -HP=S * -LI=S * (BUS5A + BUS6A + TRAINA + TRAINB)

TABLE 3.1-14
Binning Logic for General Transient Event Tree (GT)

PDS	Binning Logic
S	PV=S * LS=S * TR=S * L1=S + ((PV=S * LS=S * TR=S) + (PV=S * LS=F) + PV=F + (PV=S * LS=S * TR=F)) * ((L1=F * RW=S * HP=S * O1=S *(FC=S * HR=S + FC=F * HR=S * RH=S)) + (L1=S * RW=S * HP=S * (FC=S * HR=S + FC=F * HR=S * RH=S)) * (PV=S * LS=S * TR=F+ PV=S * LS=F + PV=F)
PDS24	CS=S * (FC=S + RH=S) * -(O1=S + PV=F + L1=S * LS=F + TR=F) * LR=S
PDS25	CS=S * (FC=S + RH=S) * -(O1=S + PV=F + L1=S * LS=F + TR=F) *-LR=S
PDS26	CS=S * (FC=S + RH=S) * (LS=F + PV=F + TR=F) * -O1=S * LR=S
PDS27	CS=S * (FC=S + RH=S) * (LS=F + PV=F + TR=F) * -O1=S * -LR=S
PDS28	CS=S * (FC=S + RH=S) * (O1=S + L1=S * (PV=F + LS=S))
PDS29	CS=S * FC=F * (RH=F + RH=B) * -(O1=S + L1=S * LS=F + PV=F + TR=F)
PDS30	CS=S * FC=F * (RH=F + RH=B) * (PV=F + TR=F) * -O1=S
PDS31	-CS=S * FC=F * (RH=F + RH=B) * (O1=S + L1=S * (PV=F +LS=F))
PDS32	-CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F + PV=F + TR=F) * LR=S
PDS32A	-CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F + PV=F + TR=F) *(LR=F + LR=B)
PDS33	-CS=S * (FC=S + RH=S) * (PV=F + TR=F) * -O1=S * LR=S
PDS33A	-CS=S * (FC=S + RH=S) * (PV=F + TR=F) * -O1=S *(LR=F + LR=B)
PDS34	-CS=S * (FC=S + RH=S) * (O1=S + L1=S * (PV=F + LS=F))
PDS32B	-CS=S * FC=F * (RH=F + RH=B) * -(O1=S + L1=S * LS=F + PV=F + TR=F)
PDS33B	-CS=S * FC=F * (RH=F + RH=B) * (PV=F + TR=F) * -O1=S
PDS34B	-CS=S * FC=F * (RH=F * RH=B) * (O1=S + L1=S *(PV=F + LS=F))
GTMELT	1

TABLE 3.1-15
Split Fraction Logic for SGTR Event Tree

Split Fraction	Split Fraction Logic
	LOSP:= OG=F + Y5=F * Z6=F
RW2	SIEVENT
HPF	RW=F + (BUS5A * TRAINB + BUS6A * TRAINA) +BUS5A * BUS6A + BUS5A * BUS2A + BUS6A * BUS2A + TRAINA *TRAINB
HP5	BUS2A * (BUS6A + BUS5A + TRAINA + TRAINB)
HPD	BUS5A + BUS6A + TRAINA + TRAINB
HP4	BUS2A
HP3	1
L1F	(HP=S * BUS3A * BUS6A * D1=F) + (TRAINA * TRAINB) + (BUS3A+ BUS6A) * (D1=F * HP=F)
L16	HP=F * BUS3A * BUS6A
L15	HP=F * (BUS3A + BUS6A)
L14	HP=F
L13	BUS3A * BUS6A * HP=S
L12	(BUS3A + BUS6A) * HP=S
L11	1
O3F	(D1=F + BUS5A) * (D2=F + BUS6A) + BUS3A * D3=F
O32	D1=F + D2=F + BUS5A + BUS6A
O31	1
OS1	1
O4F	(BUS5A + D1=F) * (BUS6A + D2=F) + D3=F * BUS3A
O42	BUS5A + BUS6A + D1=F + D2=F
O41	1

TABLE 3.1-15
Split Fraction Logic for SGTR Event Tree
(continued)

Split Fraction	Split Fraction Logic
S01	OS=F * O5=S
S02	OS=S * O4=F
S03	OS=F * O5=F
S04	O3=S
S05	L1=F * HP=F
MUF	BUS6A
MU1	1
O5F	(BUS3A * D3=F) * -O3=S
O53	HP=F * L1=S * OS=F
O5B	HP=S * L1=S * OS=S * O4=F * (BUS5A + BUS6A + D1=F + D2=F)
O5A	HP=S * L1=S * OS=S * O4=F
O5H	HP=F * L1=S * OS=S * O4=F * (BUS5A + BUS6A + D1=F + D2=F)
O5G	HP=F * L1=S * OS=S * O4=F
O5E	HP=S * L1=S * OS=F
AS1	1
LPF	RW=F + BUS6A * (BUS3A + BUS5A) + BUS5A * BUS3A * BUS6A +BUS6A * TRAINA + (BUS3A + BUS5A) * TRAINB + TRAINA * TRAINB + BUS5A * BUS6A
LP4	BUS6A + BUS3A * BUS5A + TRAINA + TRAINB
LP3	BUS3A
LP2	BUS5A
LP1	1
LRF	O5=S * (BUS5A + BUS6A) + -O5=S * (BUS6A * BUS3A * BUS5A +CC=F * (BUS5A + BUS6A))

TABLE 3.1-15
Split Fraction Logic for SGTR Event Tree

Split Fraction	Split Fraction Logic
LRB	-05=S * CC=F * BUS3A
LRA	-05=S * CC=F
LR3	-05=S * (BUS3A + BUS5A)
LR2	-05=S * (BUS6A + BUS3A) * BUS5A
LR1	-05=S
LR5	05=S * BUS3A
LR4	05=S
RHF	BUS5A * BUS6A + CC=F
RH2	BUS5A + BUS6A
RH1	1

TABLE 3.1-16
Binning Logic for Steam Generator Tube Rupture Event Tree

PDS	Binning Logic
S	RW=S * HP=S * L1=S * OS=S * (O4=S + O4=F * SO=S * O5=S) + RW=S * HP=S * L1=S * OS=S * O4=F * O5=S * SO=F * MU=S * LR=S * RH=S + RW=S * HP=S * L1=S * OS=F * SO=S * O5=S + RW=S * HP=S * L1=S * OS=F * SO=F * O5=S * MU=S * LR=S * RH=S + RW=S * HP=S * L1=F * O3=S * SO=S * LR=S * RH=S + RW=S * HP=S * L1=F * O3=S * SO=F * MU=S * LR=S * RH=S + RW=S * HP=F * L1=S * OS=S * O4=S + RW=S * HP=F * L1=S * OS=S * O4=S * O5=S * SO=S * AS=S * LP=S * LR=S * RH=S + RW=S * HP=F * L1=S * OS=S * O4=F * O5=S * SO=S * AS=S * LP=S * LR=S * RH=S + RW=S * HP=F * L1=S * OS=S * O5=S * SO=F * MU=S * AS=S * LP=S * LR=S * RH=S + RW=S * HP=F * L1=S * OS=F * O5=S * SO=S * AS=S * LP=S * LR=S * RH=S + RW=S * HP=S * L1=S * OS=F * O5=S * SO=F * MU=S * AS=S * LP=S * LR=S * RH=S + RW=F * L1=S * OS=S * O4=S
PDS48A	OS=F * SO=B + SO=F + O3=F
PDS48B	OS=S * SO=B + SO=S
SGMELT	1

TABLE 3.1-17
Split Fraction Logic for Loss of Offsite Power Event Tree

Split Fraction	Split Fraction Logic
	PWRECF:= -P1=S * -T1=S * -P2=S * -P3=S * -T2=S * -T3=S * -C1=S * -C2=S * -VF=S * -CF=S
	PWREC:= P1=S + T1=S + P2=S + P3=S + T2=S + T3=S + C2=S + C1=S + VF=S + CF=S
P11	1
PV7	1
STF	BUS5A * BUS3A
ST5	(G1=S * G2=S * G3=S) * SA=S * FO=S * (BUS5A + BUS3A)
ST4	(G1=S * G2=S * G3=S) * SA=S * FO=S * -(BUS5A + BUS3A)
ST3	(G1=S * G2=S * G3=F + G1=S * G2=F * G3=S + G1=F * G2=S *G3=S) * SA=S * FO=S * (BUS5A + BUS3A)
ST2	(G1=S * G2=S * G3=F + G1=S * G2=F * G3=S + G1=F * G2=F*G3=F) * SA=S * FO=S * -(BUS5A + BUS3A)
ST1	(G1=S*G2=F*G3=F+G1=F*G2=S*G3=F+G1=F*G2=F*G3=S)*SA=S*FO=S*(BUS5A + BUS3A)
STF	1
T11	ST=S
T12	ST=F
L1F	TRAINA * TRAINB + BUS3A * BUS6A * D1=F
L13	BUS3A * BUS6A + ST=F
L12	BUS3A + BUS6A
L11	1
P21	P1=F
T21	T1=F * ST=S
T22	T1=F * ST=F
P31	P1=F * ST=F * PV=S
T31	T1=F * ST=S
T32	T1=F * ST=F

TABLE 3.1-17
Split Fraction Logic for Loss of Offsite Power Event (continued)

Split Fraction	Split Fraction Logic
SG1	ST=F * T3=F
C12	PV=S * ST=F * T1=F * P3=S
C13	P1=F * PV=S * P3=F
C21	P1=F * PV=S * ST=S * T1=F * L1=S * LS=F
C22	P1=F * PV=S * ST=F * T1=F * L1=S * P3=S * C1=F
VF5	PV=S * L1=F
VF7	PV=F
VFF	1
CF1	PV=S * SG=S
CF3	PV=S * SG=F
CF5	PV=S * L1=F
CF7	PV=F
CFF	1
SEA	PWREC * (A5=F * A2=F * A6=F + FO=F)
C25	P1=F * PV=S * ST=F * T1=F * L1=S * P3=F * T3=S
C27	P1=F * PV=S * ST=F * T1=F * L1=S * P3=F * T3=F *SG=S * C1=F
VF1	PV=S * SG=S
VF3	PV=S * SG=F
BVF	BUS5A * BUS6A * (P2=F * T2=F)
BV2	(BUS5A + BUS6A) * (P2=F * T2=F)
BV1	1

TABLE 3.1-17
Split Fraction Logic for Loss of Offsite Power Event Tree (continued)

Split Fraction	Split Fraction
LSF	CC=F * BUS5A * BUS3A * BUS6A
LS3	CC=F * (BUS5A * BUS3A + BUS5A * BUS6A + BUS3A * BUS6A)
COA	PWREC * (A5=F * A6=F * A2=F + FO=F + SB=F)
CO2	PWREC * (A5=F * A6=F + A5=F * A2=F + A6=F * A2=F)
CO1	PWREC * (A5=F + A6=F + A2=F)
COF	1
RW2	1
HPF	RW=F +((BUS5A * BUS2A * TRAINB + BUS6A * BUS2A * TRAINA) + BUS5A * BUS6A *BUS2A) * PWRECF + TRAINA * TRAINB
HP5	(TRAINA + TRAINB + BUS5A + BUS6A) * BUS2A * PWRECF
HPD	TRAINA + TRAINB + (BUS5A + BUS6A) * PWRECF
HP4	BUS2A * PWRECF
	CC=F * (BUS5A + BUS3A + BUS6A)
LS1	1
C11	P1=F * PV=S * ST=S
SE2	PWREC * (A5=F * A6=F+ A6=F * A2=F + A5=F * A6=F)
SE1	PWREC * (A5=F + A6=F + A2=F)
SEF	1
SNA	PWREC * (A5=F * A6=F * A3=F + FO=F + SA=F)
SN2	PWREC * (A5=F * A6=F + A5=F * A3=F + A3=F * A6=F)
SN1	PWREC * (A5=F + A3=F + A6=F)
SNF	1
HRG	CC=F * -(BUS2A * BUS3A * BUS5A) * PWRECF
HRD	(BUS3A + BUS5A + BUS6A + BUS2A * BUS3A) * PWRECF
HRC	((BUS6A + BUS5A * BUS3A) * (BUS2A + BUS3A) * (BUS6A + BUS2A*BUS3A + BUS5A)) * PWRECF
HRB	((BUS5A + BUS3A) * (BUS5A + BUS2A * BUS3A + BUS2A * BUS6A +BUS3A * BUS6A) * (BUS6A + BUS2A * BUS3A + BUS5A)) * PWRECF
HRA	1

TABLE 3.1-17
Split Fraction Logic for Loss of Offsite Power Event Tree (continued)

Split Fraction	Split Fraction Logic
DPF	D3=F * BUS3A * PWREC
DP1	1
LIF	RW=F + (BUS6A * (BUS3A + BUS5A) + (BUS3A * BUS5A * BUS6A+TRAINA * BUS6A) + TRAINB * (BUS3A + BUS5A) + BUS5A * BUS6A) * PWRECF + TRAINA * TRAINB
LI4	(BUS6A + BUS3A + BUS5A) * PWRECF + TRAINA + TRAINB
LI3	BUS3A * PWRECF
LI2	BUS5A * PWRECF
LI1	1
LRF	BUS6A * BUS3A * BUS5A * PWRECF
LRD	CC+F * CO=F * BUS3A * PWRECF
LRC	CC=F * CO=F * PWRECF
LR8	(BUS3A + BUS5A) * PWRECF
LR7	(BUS6A + BUS2A * BUS5A) * PWRECF
LR6	1
RHF	(BUS6A + BUS6A) * PWRECF + (CC=F * CO=F + SN=F)
RH2	(BUS5A _ BUS6A) * PWRECF BUS3A * BUS6A) * PWRECF + TRAINA * TRAINB
FC6	(BUS5A + BUS2A * BUS3A + BUS2A * BUS6A) * PWRECF
RH1	1
CSF	RW=F + (LI=S + HP=S) * (LR=B + LR=F) * (HR=B + HR=F) + HP=F * LI=F * (TRAINA * TRAINB) + HP=F * LI=F * (BUS5A * (BUS6A + TRAINB) + BUS6A * TRAINA) * PWREC + (HR=S + LR=S) * BUS5A * BUS6A * PWRECF
CS2	RW=S * HP=F * LI=F * (BUS5A + BUS6A) * PWRECF + TRAINA + TRAINB
CS1	RW=S * HP=F * LI=F
CS5	(HR=S + LR=S) * (BUS5A + BUS6A) * PWRECF
CS4	HR=S + LR=S
CSF	1

TABLE 3.1-18
Binning Logic for Loss of Offsite Power Event Tree

PDS	Binning Logic
S	P1=S + PV=S * ST=S * T1=S + PV=S * ST=S * T1=F * L1=S * LS=S + PV=S * ST=F * T1=S + PV=S * ST=S * T1=F * LS=F * (C1=S + C2=S) * RW=S * HP=S * (FC=S * HR=S + FC=F * HR=S * RH=S) + PV=S * ST=S * L1=F * P=S * H * O1=S * (FC=S * HR=S + FC=F * HR=S * RH=S)+PV=S * ST=F * T1=F * L1=S * P3=S *(C1=S + C2=S) * RW=S * HP=S *(FC=S * HR=S + FC=F * HR=S * RH=S)+PV=S * ST=F * T1=F * L1=S * P3=F * T3=S * C2=S * RW=S * HP=S *(FC=S * HR=S + FC=F * HR=S * RH=S)+ PV=S * ST=F * T1=F * L1=S * P3=F * T3=F * SG=S * (C1=S + C2=S)* RW=S * HP=S*(FC=S * HR=S + FC=F * HR=S * RH=S) + PV=S * ST=F * T1=F * L1=F *(P2=S + T2=S)* RW=S * HP=S *O1=S * (FC=S * HR=S + FC=F * HR=S * RH=S)+PV=F * ST=S * T1=S + PV=F * ST=S * T1=F * L1=S * P2=S * BV=S * LS=S + PV=F * ST=S * T1=F * L1=S * P2=S * (LS=F + BV=F) * RW=S * HP=S * (FC=S * HR=S + FC=F * HR=S * RH=S)+PV=F * ST=S * T1=F * L1=S * P2=F * (T2=S + T2=F) * BV=S * LS=S + PV=F * ST=S * T1=F * L1=S * (P2=F * T2=S + P2=F * T2=F) * (BV=S + BV=F) * RW=S * HP=S * (FC=S * HR=S + FC=F * HR=S * RH=S) + PV=F * ST=S * T1=F * L1=F * (P2=S + P2=F * T2=S + P2=F * T2=F) * RW=S * HP=S * O1=S * (FC=S * HR=S + FC=F * HR=S * RH=S)+ PV=F * ST=F * T1=S + PV=F * ST=F * T1=F * L1=S * (P2=S + T2=S) * BV=S * LS=S + PV=F * ST=F * T1=F * L1=S * (P2=S + T2=S) * (BV=F + LS=F) * HP=S * HR=S * (FC=S + RH=S) + PV=F * ST=F * T1=F * L1=F * (P2=S + P2=F * T2=S) * (RW=S * HP=S * O1=S * (FC=S * HR=S + FC=F * HR=S

TABLE 3.1-18
Binning Logic for Loss of Offsite Power Event Tree
(continued)

PDS	Binning Logic
PDS1	-VF=F * ST=F * CS=S * (FC=S + RH=S) * -(O1=S + L1=S * -SG=F +PV=F * -BV=S) * LR=S
PDS2	-VF=F * ST=F * CS=S * (FC=S + RH=S) * (PV=F * -BV=S) *-(O1=S + L1=S * -SG=F) * (HR=S + LR=S)
PDS3	-VF=F * ST=F * CS=S * (FC=S + RH=S) * PV=F * -BV=S *-(O1=S + L1=S * -SG=F) * -(LR=S + HR=S)
PDS4	-VF=F * ST=F * CS=S * (FC=S + RH=S) * (O1=S + L1=S * -SG=F)
PDS5	-VF=F * ST=F * CS=S * FC=F * -RH=S * -(O1=S + L1=S * -SG=F + PV=F* -BV=S)
PDS6	-VF=F * ST=F * CS=S * FC=F * -RH=S
PDS7	-VF=F * ST=F * -CS=S * (FC=S + RH=S) * -(O1=S + L1=S * -SG=F + PV=F *-BV=S)
PDS8	-VF=F * -CS=S * ST=F * (FC=S + RH=S) * PV=F * -BV=S *-(O1=S+L1=S * -SG=F)
PDS9	-VF=F * ST=F * -CS=S * (FC=S + RH=S) * (O1=S + L1=S * -SG=F)
PDS10	-VF=F * ST=F * -CS=S * FC=F * -RH=S * -(O1=S + L1=S * -SG=F + PV=F* -BV=S)
PDS11	-VF=F * ST=F * -CS=S * FC=F * -RH=S

TABLE 3.1-18
Binning Logic for Loss of Offsite Power Event Tree (continued)

PDS	Binning Logic
PDS12	CF=S*ST=F*CS=S*(FC=S+RH=S)*-(O1=S+L1=S*-SG=F+PF=F*- BV=S
PDS13	CF=S * CS=S * (FC=S + RH=S)
PDS14	CF=S * CS=S * FC=F * -RH=S
PDS15	CF=S*-CS=S*(FC=S+RH=S)*-(O1=S+L1=S*-SG=F+PV=F*-BV=S)
PDS16	CF=S*-CS=S*(FC=S+RH=S)*PV=F*-BV=S*-(O1=S+L1=s*-SG=F)
PDS17	CF=S * -CS=S * (FC=S + RH=S) * (O1=S + L1=S * -SG=F)
PDS18	CF=S * -CS=S * FC=F * -RH=S * -(O1=S + L1=S * -SG=F +PV=F * -BV=S)
PDS19	CF=S * -CS=S * FC=F * -RH=S * PV=F * -BV=S *-(O1=S + L1=S * SG=F)
PDS20	CF=S * -CS=S * FC=F * -RH=S * (O1=S + L1=S * -SG=F)
PDS21	CF=F * -(O1=S + L1=S * -SG=F + PV=F * -BV=S)
PDS22	CF=F * PV=F * -BV=S * -(O1=S + L1=S * -SG=F)
PDS23	CF=F * (O1=S + L1=S * -SG=F)
PDS24	CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F + PV=F *-BV=S) * (LR=S + HR=S)
PDS25	CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F + PV=F* -BV=S) * -(LR=S + HR=S)
PDS26	CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F) * PV=F *-BV=S (LR=S + HR=S)
PDS27	CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F) * PV=F * -BV=S* -(LR=S + HR=S)
PDS28	CS=S * (FC=S + RH=S) * (O1=S + L1=S * (LS=F + PV=F *-BV=S))
PDS34B	-CS=S * FC=F * -RH=S * (O1=S + L1=S * (LS=F +PV=F * -BV=S))
LSPMLT	1

TABLE 3.1-18
Binning Logic for Loss of Offsite Power Event Tree
(continued)

PDS	Binning Logic
PDS29	CS=S * FC=F * -RH=S * -(O1=S + L1=S * LS=F + PV=F * -BV=S)
PDS30	CS=S * FC=F * -RH=S * -(O1=S + L1=S * LS=F) * PV=F *-BV=S
PDS31	CS=S * FC=F * -RH=S * (O1=S + L1=S * (LS=F + PV=F *-BV=S))
PDS32	-CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F + PV=F *-BV=S) * (HR=S + LR=S)
PDS32A	-CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F + PV=F *-BV=S) * -(LR=S + HR=S)
PDS33	-CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F) * (PV=F* -BV=S) * (HR=S + LR=S)
PDS33A	-CS=S * (FC=S + RH=S) * -(O1=S + L1=S * LS=F) * PV=F *-BV=S * -(LR=S + HR=S)
PDS34	-CS=S * (FC=S + RH=S) * (O1=S + L1=S * (LS=F + PV=F *-BV=S))
PDS32B	-CS=S * FC=F * -RH=S * -(O1=S + L1=S * LS=F +PV=F * -BV=S)
PDS33B	-CS=S * FC=F * -RH=S * -(O1=S + L1=F * LS=F) *PV=F * -BV=S

TABLE 3.1-19
Split Fraction Logic for ATWS Event Tree

Split Fraction	Split Fraction
RT2	INIT=LOSP
RT3	INIT=RXTRIP
RT1	1
PL1	1
TTF	D1=F * D2=F
TT3	D1=F + D2=F
TT2	INIT=TTRIP
TT1	1
L1F	(BUS3A + BUS6A) * PL=F + BUS3A * BUS6A * D2=F * PL=S
L1A	PL=F
L19	PL=S * BUS3A * BUS6A
L18	PL=S * (BUS3A + BUS5A)
L17	PL=S
PR4	(BUS5A + D1=F) * (BUS6A + D2=F)
PR3	BUS5A + BUS6A + D1=F + D2=F
PR2	1
SR3	BUS5A * BUS6A
SR2	BUS5A + BUS6A
SR1	1
RW2	1
BRF	BUS5A + BUS6A + CC=F
BR2	BUS3A
BR1	1
MD3	BR=F * BUS3A
MD2	BR=F
MD1	1

TABLE 3.1-19
Split Fraction Logic for ATWS Event Tree
(continued)

Split Fraction	Split Fraction
O2F	BUS5A + BUS6A + D1=F + D2=F
O21	1
HPF	RW=F + (BUS5A * BUS2A * TRAINB + BUS6A * BUS2A * TRAINA)+BUS5A * BUS6A * BUS2A + TRAINA * TRAINB
HP5	(TRAINA * TRAINB + BUS5A * BUS6A) * BUS2A
HPD	BUS5A + BUS6A + TRAINA + TRAINB
HP4	BUS2A
HP3	1
FCF	SA=F + BUS5A * (BUS2A + BUS3A + BUS6A) + BUS2A * BUS3A * BUS6A + TRAINA * TRAINB FC6 BUS5A + BUS2A * BUS3A + BUS2A * BUS6A + BUS3A * BUS6A
FC5	BUS2A + BUS3A + BUS6A
FC4	1
HRF	BUS5A * BUS6A
HRI	HP=S * BUS5A
HRH	HP=S * (BUS6A + BUS2A)
HRG	HP=S * CC=F
HRD	HP=S * BUS5A * BUS2A
HRC	HP=S * BUS2A * BUS3A
HRB	HP=S * (BUS2A + BUS3A)
HR1	1
LIF	RW=F + BUS6A * (BUS3A + BUS5A) +BUS5A * BUS3A * BUS6A +BUS6A * TRAINA + (BUS3A + BUS5A) * TRAINB + TRAINA *TRAINB + BUS5A BUS6A

TABLE 3.1-19
Split Fraction Logic for ATWS Event Tree
(continued)

Split Fraction	Split Fraction
LRD	CC=F * BUS3A LRC CC=F
LR8	BUS3A + BUS5A
LR7	BUS6A + BUS3A * BUS5A
LR6	1
RH2	BUS5A + BUS6A
RH1	1
LI4	BUS6A + BUS3A * BUS5A + TRAINA + TRAINB
LI3	BUS3A
LI2	BUS5A
LI1	1
LRF	CC=F+ BUS6A * BUS3A * BUS5A
CSF	RW=F + (LI=S + HP=S) * (LR=B + LR=F) * (HR=F + HR=B) + -(LI=S + HP=S)* (TRAINA * TRAINB + BUS5A * (BUS6A + TRAINB) +BUS6A * TRAINA) +(HR=S + LR=S) * BUS5A * BUS6A
CS2	RW=S * -HP=S * - LI=S * (BUS5A + BUS6A + TRAINA + TRAINB)
CS1	RW=S * -HP=S * -LI=S
CS5	(HR=S + LR=S) * (BUS5A + BUS6A)
CS4	HR=S + LR=S

TABLE 3.1-20
Binning Logic for ATWS Event Trees

PDS	Binning Logic
S	(RT=S) + (PL=S * L1=S * SR=S * RW=S * BR=S)+ (PL=S * L1=S * SR=S * RW=S * BR=F * MD=S)+ (PL=S * L1=S * SR=S * RW=F * MD=S) + (PL=S * L1=S * SR=F * RW=S * O2=S * HP=S * FC=S * HR=S)+ (PL=S * L1=S * SR=F * RW=S * O2=S * HP=S * FC=F * HR=S * RH=S)+ (PL=F * TT=S * L1=S * PR=S * SR=S * RW=S * BR=S)+ (PL=F * TT=S * L1=S * PR=S * SR=S * RW=S * BR=F * MD=S)+ (PL=F * TT=S * PR=S * SR=S * RW=F * MD=S)+ (PL=F * TT=S * PR=S * SR=F * RW=S * HP=S * FC=S * HR=S)+ (PL=F * TT=S * PR=S * SR=F * RW=S * HP=S * FC=F * HR=S *RH=S)
PDS24	CS=S * (FC=S + RH=S) * -(PR=F + SR=F + TT=F) * LR=S
PDS25	CS=S * (FC=S + RH=S) * -(PR=F + SR=F + TT=F) * (LR=F +LR=B)
PDS26	CS=S * (FC=S + RH=S) * (PR=F + SR=F + TT=F) * LR=S
PDS27	CS=S * (FC=S + RH=S) * (PR=F + SR=F + TT=F) * (LR=F + LR=B)
PDS29	CS=S * FC=F * (RH=F + RH=B) * -(PR=F + SR=F + TT=F)
PDS30	CS=S * FC=F * (RH=F + RH=B) * (PR=F + SR=F + TT=F)
PDS32	-CS=S * (FC=S + RH=S) * -(PR=F + SR=F + TT=F) * LR=S
PDS32A	-CS=S * (FC=S + RH=S) * -(PR=F + SR=F + TT=F) * (LR=F +LR=B)
PDS33	-CS=S * (FC=S + RH=S) * (PR=F + SR=F + TT=F) * LR=S
PDS33A	-CS=S * (FC=S + RH=S) * (PR=F + SR=F + TT=F) * (LR=F +LR=B)
PDS32B	-CS=S * FC=F * (RH=F + RH=B) * -(PR=F + SR=F + TT=F)
PDS33B	-CS=S * FC=F * (RH=F + RH=B) * (PR=F + SR=F + TT=F)
ATMELT	1

TABLE 3.1-21
Split Fraction Logic for Event Tree: ELOCA

Split Fraction	Split Fraction Logic
	LOSP:= OG=F + Y5=F * Z6=F
RW1	1
LPF	RW=F +BUS6A * (BUS3A + BUS5A) +BUS3A * BUS5A * BUS6A + TRAINA * BUS6A +TRAINB * (BUS3A + BUS5A) +BUS5A * BUS6A+TRAINA * TRAINB
LP4	BUS6A + BUS3A * BUS5A + TRAINA + TRAINB
LP3	BUS3A
LP2	BUS5A
LP1	1
FCF	BUS5A * (BUS2A + BUS3A + BUS6A) +BUS2A * BUS3A * BUS6A+TRAINA * TRAINB +SA=F
FC6	(BUS2A * BUS3A) + (BUS5A + BUS2A * BUS6A) + (BUS3A*BUS6A)
FC5	BUS6A + BUS3A + BUS2A
FC4	1
LRF	RW=F + LP=F + BUS6A * BUS3A * BUS5A + CC=F * (BUS6A+BUS5A)
LRD	CC=F * BUS3A
LRC	CC=F
LR8	BUS3A + BUS5A
LR7	BUS5A * BUS3A + BUS6A
LR6	1
RHF	BUS5A * BUS6A + CC=F
RH2	BUS5A + BUS6A
RH1	1
CSF	RW=F + LP=S * LR=F + LP=F * (TRAINA * TRAINB + BUS5A * (BUS6A + TRAINB) + BUS6A * TRAINA) + LP=S * LR=S * BUS6A*BUS5A
CS2	RW=S * LP=F * (BUS5A + BUS6A)
CS1	RW=S * LP=F
CS5	LR=S * (BUS5A + BUS6A)
CS4	LR=S

TABLE 3.1-22
Binning Logic for LOCA Beyond ECCS Event Tree

PDS	Binning Logic
PDS36	CS=S * (FC=S + RH=S)
PDS37	CS=S * FC=F * -RH=S
PDS39	-CS=S * FC=S * LP=S
PDS40	-CS=S * FC=F + RW=F
ELMELT	1

TABLE 3.1-23: SUPPORT SYSTEM TO SUPPORT SYSTEM DEPENDENCY MATRIX (Page 1 of 5)

Effect On Other Support Systems or Other Components

Support System Failed	6.9 KV Buses				DC Power Buses				480V Buses				Emergency Diesel Generators			Emergency DG Fuel Oil Pumps		
	5	6	2	3	21	22	23	24	5A	6A	2A	3A	21	22	23	21	22	23
Station Aux Transformer	**	**	**	**	(a)	(a)	(b)	(a)	(c)	(c)	(c)	(c)						
6.9KV Bus 5 (d)	--		**		(a)	(a)			(f)		(f)							
6.9KV Bus 6 (d)		--		**			(b)	(a)		(f)		(f)						
6.9KV Bus 2 (e)			--			(a)					(f)							
6.9KV Bus 3 (e)				--			(b)					(f)						
DC Bus 21	(g)		(h)		--				(i)			(i)	(k)					
DC Bus 22		(g)		(h)		--				(i)	(i)			(k)	(k)			
DC Bus 23							--		(j)			(j)	(l)	(l)				
DC Bus 24								--		(j)	(j)				(l)			
480V Bus 5A					(m)				--				**			**		
480V Bus 6A								(m)		--					**			**
480V Bus 2A						(m)					--			(n)			**	
480V Bus 3A							(m)					--		(n)				
EDG 21(o)					(m)				**				--			**		
EDG 22						(m)	(m)				**	**		--			**	
EDG 23								(m)		**					--			**
EDG Fuel Oil Pumps 21													(p)	(q)		--		
EDG Fuel Oil Pumps 22														(p)	(q)		--	
EDG Fuel Oil Pumps 23													(q)		(p)			--
ESFAS Train A							(r)		(s)	(s)	(s)	(s)	(t)	(t)	(t)			
ESFAS Train B							(r)		(s)	(s)	(s)	(s)	(t)	(t)	(t)			
Essential SWS													**	**	**			
Non Essential SWS																		
Component Cooling																		
Reactor Prot Sys(u)																		
EDG Bldg Ventilation													(v)	(v)	(v)			

** Fails when support system fails

TABLE 3.1-23: SUPPORT SYSTEM TO SUPPORT SYSTEM DEPENDENCY MATRIX (Page 2 of 5)

Effect On Other Support Systems or Other Components

Support System Failed	ESF Actuation Train A	ESF Actuation Train B	Service Water Pumps 21	22	23	24	25	26	Component Cooling Pumps 21	22	23	Reactor Protection System	EDG Building Ventilation Fans 318	319	320	321	322
Station Aux Transformer			(w)	(w)	(w)	(w)	(w)	(w)	(w)	(w)	(w)	(x)					
6.9KV Bus5 (d)			(w)	(w)		(w)			(w)	(w)							
6.9KV Bus6 (d)					(w)		(w)	(w)			(w)	(y)					
6.9KV Bus2 (e)				(w)						(w)		(y)					
6.9KV Bus3 (e)							(w)										
DC Bus 21	**											(z)					
DC Bus 22		**										(z)					
DC Bus 23																	
DC Bus 24																	
480V Bus 5A			**			**			**				(bb)	**		**	
480V Bus 6A					**			**			**	(y)					
480V Bus 2A				(aa)			(aa)			**		(y)					
480V Bus 3A				(aa)			(aa)								**		**
EDG 21(o)			**			**			**				(bb)	**		**	
EDG 22				**			**			**					**		**
EDG 23					**			**			**						
EDG Fuel Oil Pumps 21																	
EDG Fuel Oil Pumps 22																	
EDG Fuel Oil Pumps 23																	
ESFAS Train A	--											(cc)					
ESFAS Train B		--										(cc)					
Essential SWS																	
Non Essential SWS									**	**	**						
Component Cooling									--	--	--						
Reactor Prot Sys(u)												--					
EDG Bldg Ventilation													--	--	--	--	--

** Fails when support system fails

TABLE 3.1-23 (Page 3 of 5)
Indian Point 2 Support System-to-Support System Table

NOTES:

a. Loss of power to the associated battery charger; operator action is necessary to restore power to the charger.

b. Loss of power to the associated battery charger; power is automatically restored when the emergency diesel generator loads 480V Bus 3A

c. Power to this bus is supplied by the associated emergency diesel generator on loss of normal supply.

d. Loss of either of these 6.9-kV buses creates an undervoltage condition at the associated 480V bus, which starts all three emergency diesel generators, and, in conjunction with a **"unit trip"** signal, trips the feeds from the 6.9-kV buses to the 480V buses (2A, 3A, 5A and 6A) and allows the diesel generator output breakers to close when other interlocks are satisfied.

e. Loss of either of these 6.9-kV buses creates an undervoltage condition at the associated 480V bus, which starts at three emergency diesel generators. Operator action in necessary to close the diesel generator output breaker to supply power to the affected bus. A **"unit trip"** signal is not required to permit generator output breakers to close when other interlocks are satisfied.

f. The equipment, which was tripped by the undervoltage relays, restarts when the associated emergency diesel generator closes on to the bus.

g. Loss of this DC bus prevents transfer to startup transformer on unit trip. This results in loss of power to the indicated 6.9-kV bus.

h. If DC power fails, no equipment on this bus can start or trip. The affected buses are assumed to fail.

i. Primary supply to the DC automatic transfer device for this 480V bus.

j. Backup supply to the DC automatic transfer device for this 480V bus.

k. Primary supply to the DC automatic transfer device for this emergency diesel generator.

l. Backup supply to the DC automatic transfer device for this emergency diesel generator.

m. Loss of power to the associated battery charger. DC power is assumed to fall in 2 hours (3 hours for Battery 22) with no power to the charger.

TABLE 3.1-23 (Page 4 of 5)
Indian Point 2 Support System-to-Support System Dependency Table

n. Failure of either Bus 2A or 3A prevents emergency diesel generator 22 from loading on to that specific bus.

o. Emergency diesel generators are only questioned if there is an undervoltage condition on the associated bus.

p. Primary fuel oil transfer pump for the indicated emergency diesel generator. Emergency diesel generator (EDG) fuel oil transfer pump 21, powered from motor control center 29A (Bus 5A), EDG fuel oil transfer Pump 22, powered from motor control center 24A (Bus 2A), and EDG fuel oil pump 23 powered from motor control center 27A (Bus 6A) are all stripped on loss of offsite power. Operator action is required to reenergize these motor control centers. **Note: The power supply for emergency diesel generator fuel oil transfer Pump 23 was changed to motor control center 26B (Bus 6A) after the 1991 refueling outage. Although this is not credited in the model, this pump is now automatically picked up when power is supplied to Bus 6A from EDG 23.**

q. Reserve fuel oil transfer pump for the indicated emergency diesel generator.

r. Automatic safety injection signal from the indicated channel strips the motor control center that supplies the associated battery charger.

s. Loss of one-half of the 480V strip and load on safety injection signals (train A-Sl-11X; train B-Sl-22X). The emergency diesel generators will start and reload the 480V buses on bus undervoltage.

t. Loss on one-half of the emergency diesel generator start signal on safety injection (train A-Sl-12X; train B-Sl-22X). The emergency diesel generators will start and reload the 480V buses on bus undervoltage.

u. Although the reactor protection system is not actually a support system, it is included in the support systems model for ease in quantification and mapping of **"anticipated transient without scram"** sequences.

v. The number of fans required to maintain proper EDG building temperature depends on ambient temperature and the number of operating EDGs

w. Three service water pumps are selected to supply the essential header loads; three service water pumps are selected to supply the nonessential header loads. The pumps selected to supply a particular header are determined by selector switch in the control room. Either set of three pumps (21, 22 and 23 or 24, 25 and 26) is equally likely to supply a particular header. The following conditions apply to automatic start of the service water and component cooling pumps. It should be noted that, however, that this analysis includes a restart challenge for all service water and component cooling water pumps, under all conditions.

- **Station Blackout.** Service water pumps selected to supply the essential header restart automatically. Service water pumps supplying the nonessential header must be restarted by operator action. Component cooling pumps restart automatically.

- **Safety Injection.** All service water pumps selected to supply the essential header are sent automatic start signals. The service water pumps supplying the nonessential header and the component cooling pumps receive start/restart signals dependent upon the plant conditions following the safety injection.

- **Station Blackout and Safety Injection.** All service water pumps selected to supply the essential header restart (or start) when the associated emergency diesel generator starts. The service water pumps supplying the nonessential header restart when active recirculation is started; one pump starts when RS-2 is switched; an additional pump is started when RS-5 is switched if three emergency diesel generators are running. One component cooling pump is started when RS-2 is switched; an additional pump is started when RS-5 is switched if three emergency diesel generators are running and two service water pumps are running on the nonessential header.

TABLE 3.1-23 (Page 5 of 5)
Indian Point 2 Support System-to-Support System Dependency Table

x. Power is lost to the control rod drive motor generator sets. The reactor trip breakers do not have to open for reactor trip success.

y. Loss of power to one rod drive motor generator set.

z. Power is lost to the associated undervoltage trip device of the reactor trip breaker and the shunt trip device.

aa. Service water pumps 22 and 25 can be supplied from 480V buses 2A or 3A. Normally, one pump is supplied from Bus 2A, and the other pump is supplied from Bus 3A.

bb. EDG Building fan 318 is normally fed from Bus 5A with a backup supply from Bus 3A

cc. Loss of automatic reactor trip signal from safeguards actuation for one reactor trip logic channel.

TABLE 3.1-24: SUPPORT SYSTEM TO FRONTLINE SYSTEM DEPENDENCY MATRIX (Page 1 of 4)

Effect On Frontline Systems and Components

Support System Failed	Turbine Trip	MSIV's	Auxiliary Feedwater Pumps			Main Stm Dump Valves	Safety Injection Pumps			RHR Pumps		Injection System MOVs Train		Pressurizer PORVs		Containment Spray Syst Pumps		Containment Spray Syst MOVs		Reactor Coolant Pump Seals
			21	22	23		21	22	23	21	22	A	B	455C	456	21	22	866 A&C	866 B&D	
Station Aux Transformer			(a)	(b)	(a)															
6.9KV Bus 5			(a)	(b)	(a)															
6.9KV Bus 6			(a)	(b)	(a)															
6.9KV Bus 2																				
6.9KV Bus 3																				
DC Bus 21	(c)	(d)		(e)		**									**					
DC Bus 22	(c)	(d)		(e)										**						
DC Bus 23																				
DC Bus 24																				
480V Bus 5A				(b)			**					**			(f)	**		**		
480V Bus 6A				(b)	**				**		**		**	(f)			**		**	
480V Bus 2A								(g)												
480V Bus 3A			**					(g)		**										
ESFAS Train A	(h)	(i)	(j)	(k)	(j)							(l)				**				
ESFAS Train B	(h)	(i)	(j)	(k)	(j)								(l)				**			
Essential Service Water																				
Non Essential Service Water							(m)	(m)	(m)	(m)	(m)									**
Component Cooling							(m)	(m)	(m)	(m)	(m)									**
Reactor Prot Sys(n)	(o)																			

** Fails when the support system fails

TABLE 3.1-24: SUPPORT SYSTEM TO FRONTLINE SYSTEM DEPENDENCY MATRIX (Page 2 of 4)

Effect On Frontline Systems and Components

Support System Failed	Containment Fan Cooler Units 21	22	23	24	25	Recirculation Pumps 21	22	RHR Heat Exchangers 21	22	Auxiliary CCW Pumps 21	22	Spray Recirc MOVs A	B	Boric Acid Transfer Pumps Train 21	Train 22	Primary Water Makeup Pumps 21	22	Charging Pumps 21	22	23	Stm Gen Atmos Relief Valves	Shutdown Cooling Suction MOV 730	MOV 731
Station Aux Transformer	(p)	(p)	(p)	(p)	(p)																		
6.9KV Bus 5	(p)	(p)																					
6.9KV Bus 6					(p)																		
6.9KV Bus 2			(p)																				
6.9KV Bus 3				(p)																			
DC Bus 21																							
DC Bus 22																					(q)		
DC Bus 23																							
DC Bus 24																							
480V Bus 5A	**	**				**				**		**(r)						**				**	
480V Bus 6A					**		**				**		**(r)	**		**	**			**			**
480V Bus 2A			**																				
480V Bus 3A				**											**				**		(q)		
ESFAS Train A										**													
ESFAS Train B											**												
Essential SWS	**	**	**	**	**																		
Non Essential SWS						**	**	**	**	**	**												
Component Cooling						(t)	(t)	**	**	**	**							(s)	(s)	(s)			
Reactor Prot Sys(n)																							

** Fails when the support system fails

TABLE 3.1-24 (Page 3 of 4)
Indian Point 2 Support System-to-Frontline System Dependency Table

NOTES:

a. Motor-driven auxiliary boiler feed pumps start automatically on loss of offsite power (undervoltage on 480V Bus 5A or 6A).

b. Auxiliary boiler feed pump 22 (steam-driven) will start automatically on a loss of offsite power (undervoltage on 480V Bus 5A or 6A).

c. Loss of one turbine trip train.

d. Loss of a DC bus results in a failure of one of two supply and one of two exhaust valves for each main steam isolation valve.

e. Loss of a DC power bus fails one of two redundant signals to the steam admission valve for auxiliary boiler feed Pump 22.

f. The power-operated relief valve block valve will fail due to loss of power to its associated motor control center.

g. High pressure safety injection Pump 22 can receive power from 480V Bus 2A or 3A. This analysis conservatively assumes that this pump receives power only from Bus 2A. With failure of safety injection Pump 21, motor-operated valve 851B will automatically close with failure of safety injection Pump 23, motor-operated valve 851A will automatically close. These actions split the high pressure injection system into two separate trains.

h. Loss of one (of two) turbine trip valves on safety injection signals.

i. Loss of one (of two) main steam line isolation signals to the main steam isolation valves.

j. Loss of one (of two) safety injection start signals to the motor-driven auxiliary boiler feed pumps.

k. Auxiliary boiler feed Pump 22 will start on two of three low-low steam generator levels in two of the four steam generators with or without a safety injection signal present. This pump does not receive an automatic safety injection signal.

l. Loss on the safety injection signal to operate motor-operated valves. The following motor-operated valves are affected (will not operate).

   Train A - 746, 822A
   Train B - 747, 822B

   All other motor-operated valves are normally in the required accident position or are deenergized in their required accident condition.

TABLE 3.1-24 (Page 4 of 4)
Indian Point 2 Support System-to-Frontline System Dependency Table

m. Equipment may only be operated during injection without component cooling. Alternate cooling may be provided by operator action, however, from the City Water or Primary Makup Water systems.

n. Although not actually a support system, it is included in the support systems model for ease in quantification and mapping of ATWS sequences.

o. Turbine trip will not occur if reactor trip breakers do not open.

p. Running containment fan coolers will stop and restart when their power supply is re-energized by the EDGs. Non-running containment fan coolers will start when their power supply is reenergized. This analysis assumes a restart challenge for all coolers.

q. Power is supplied from Instrument Bus 23 which can be fed from either AC Bus 3A or DC Bus 23

r. Loss of one-half of the containment spray recirculation paths due to loss of power to the motor control center associated with the motor-operated valve that supplies spray recirculation.

s. Pumps may be run at maximum speed to extend poential operating time without cooling. Alternate cooling may be provided by operator action from the City Water or Primary Makeup Water Systems

t. Auxiliary component cooling water is required to protect the Recirculation Pumps during the injection phase. Component cooling is required during the recirculation phase.

TABLE 3.1-25
Split Fraction Logic for Event Tree EPS

Split Fraction	Split Fraction
OGF	INIT=LOSP + INIT=LOSPA
OG1	1
Y5F	OG=F
Y51	1
Z6F	OG=F
Z61	1
W2F	INIT=LO692 + INIT=LO692A + OG=F + Y5=F
W21	1
X3F	INIT=LO693 + INIT=LO693A + OG=F + Z6=F
X32	OG=S * W2=F
X31	1
D1F	INIT=LODC21 + INIT=LDC21A
D12	OG=F + Y5=F
D11	1
D2F	INIT=LODC22 +INIT=LDC22A
D23	(OG=F + Y5=F + W2=F) * D1=F
D22	(OG=F + Y5=F + W2=F) * D1=S
D21	1
G1F	1
G2F	D2=F * D3=F
G2S	W2=S * X3=S * D1=S * D2=S
G2C	G1=F * (D1=F * D2=F * D3=S * D4=S +Z6=F * D1=F * D3=S +Y5=F * D2=F * D3=S + (OG=F + Z6=F * Y5=F) *((D1=S * D3=S) * D2=S + D3=S * D4=S))
G23	G1=S * (D1=F * D2=F * D3=S * D4=S +Z6=F * D1=F * D3=S +Y5=F * D2=F * D3=S + (OG=F + Z6=F * Y5=F) * ((D1=S *D3=S) * D2=S + D3=S * D4=S))

TABLE 3.1-25
Split Fraction Logic for Event Tree EPS
(continued)

Split Fraction	Split Fraction Logic
G2B	G1=F * (Z6=S * D1=F * D2=S + D1=F * D2=F * D4=F +(Y5=F * Z6=S * D1=S) * (D2=S + D2=F * D4=F) +(Y5=F * Z6=F * D1=S * D2=F * D4=F))
G2A	G1=S * (Z6=S * D1=F * D2=S + D1=F * D2=F * D4=F +(Y5=F * Z6=S * D1=S) * (D2=S + D2=F * D4=F) +(Y5=F * Z6=F * D1=S * D2=F * D4=F))
G22	(D1=F * D3=F + Y5=S * D1=S) * (OG=F + Z6=F + D2=F) * D4=S
G21	(D1=F * D3=F + Y5=S * D1=S) * (Z6=S * D2=S + D2=F * D4=F)
G2F	1
G3F	D2=F * D4=F
G3S	Z6=S * D2=S
D34	(OG=F + Z6=F + X3=F) * D1=F * D2=F
D33	(OG=F + Z6=F + X3=F) * (D2=F + D1=F)
D32	(OG=F + Z6=F + X3=F) * D1=S * D2=S
D31	1
D45	(OG=F + Z6=F) * D1=F * D2=F * D3=F
D44	(OG=F + Z6=F) * (D1=F * D2=F + D2=F * D3=F + D1=F * D3=F)
D43	(OG=F + Z6=F) * (D1=F + D2=F + D3=F)
D42	(OG=F + Z6=F) * (D1=S * D2=S * D3=S)
D41	1
G1F	D1=F * D3=F
G11	(D1=S * D2=F * D3=F * D4=F) * (OG=F + Y5=F)
G12	Z6=S * D1=F * D2=S + D1=F * D2=F * D4=F +(Y5=F * Z6=S * D1=S) * (D2=S + D2=F * D4=F) + (Y5=F * Z6=F* D1=S * D2=F * D4=F)
G13	D1=F * D2=F * D3=S * D4=S +Z6=F * D1=F * D3=S +Y5=F * D2=F * D3=S +(OG=F + Z6=F * Y5=F) * ((D1=S * D3=S) * D2=S + D3=S *D4=S)
G1S	Y5=S * D1=S

TABLE 3.1-25
Split Fraction Logic for Event Tree EPS
(continued)

Split Fraction	Split Fraction Logic
	G1CHALW:=(G1 IS CHALLENGED)
	G1CHAL:= (OG=F + Y5=F)
	G2CHALW:=(G2 IS CHALLENEGED)
	G2CHAL:= (OG=F + W2=F + X3=F)
	G3CHALW:=(G3 IS CHALLANGED)
	G3CHAL:= (OG=F + Z6=F)
G3D	G1=F * -G1CHAL * G2=F * -G2CHAL
G3C	G1=F * -G1CHAL * G2=S * -G2CHAL
G3B	G1=S * -G1CHAL * G2=F * -G2CHAL
G33	G1=S * -G1CHAL * G2=S * -G2CHAL
G32	G1CHAL * G2=S * -G2CHAL + G1=S * -G1CHAL * G2CHAL
G31	G1CHAL * G2CHAL
G3F	1
A5F	(OG=F + Y5=F) * G1=F + D1=F * D3=F
A52	OG=F + Y5=F + D1=F
A51	1
A6F	(OG=F + Z6=F) * G3=F + D2=F * D4=F
A62	OG=F + Z6=F + D2=F
A61	1
A3F	G2=F * (OG=F +Z6=F) + D2=F * D3=F
A32	D2=F + X3=F + Z6=F + OG=F
A31	1
A2F	G2=F * (OG=F + Y5=F) + D2=F * D3=F
A22	D1=F + W2=F + Y5=F + OG=F
A21	1
FOF	A5=F * A6=F * A2=F
FO1	A5=F * A6=F + A5=F * A2=F + A6=F * A2=F
FO2	A5=F + A6=F + A2=F
FO3	A5=S * A6=S * A2=S

TABLE 3.1-26
Split Fraction Logic for Event Tree AUXSYS

Split Fraction	Split Fraction Logic
	TRAINA:= EA=F + D1=F
	TRAINB:= EB=F + D2=F
	SIEVENT:= INIT=LLOCA + INIT=MLOCA + INIT=SLOCA +
	INIT=SGTR + INIT=SLBIC + INIT=SLBOC + INIT=BECCSL
EAF	INIT=VSEQ + SIEVENT * D1=F
EA3	-SIEVENT
EAA	SIEVENT * D2=F
EA1	SIEVENT
EBF	INIT=VSEQ + SIEVENT * D2=F
EB3	-SIEVENT
EBA	SIEVENT * D1=F
EBC	SIEVENT * EA=F * D1=S
EB1	SIEVENT * EA=S
SAF	SIEVENT * (A5=F * A6=F + A2=F) *(A5=F + A6=F)
SA6	SIEVENT * (A5=F + A6=F + A2=F)
SA5	SIEVENT * A5=S * A6=S * A2=S
SAF	-SIEVENT * A5=F * A6=F * A2=F
SCF	-SIEVENT * (A5=F * A6=F * A2=F)
SCA	-SIEVENT * (A5=F * A6=F + A2=F) *(A5=F + A6=F)
SC6	-SIEVENT * (A5=F + A6=F + A2=F)

TABLE 3.1-26
Split Fraction Logic for Event Tree AUXSYS
(continued)

Split Fraction	Split Fraction
SC5	-SIEVENT * A5=S * A6=S * A2=S
	BUS5A:= A5=F + (SA=F + FO=F) * -(Y5=S * D1=S)
	BUS6A:= A6=F + (SA=F + FO=F) * -(Z6=S * D2=S)
	BUS2A:= A2=F + (SA=F + FO=F) * -(W2=S * X3=S * D1=S * D2=S)
	BUS3A:= A3=F + (SA=F + FO=F) * -(W2=S * X3=S * D1=S * D2=S)
SBF	INIT= LOSW + INIT=LOSWA + BUS5A * BUS6A * BUS3A
SBA	BUS5A * (BUS6A + BUS3A)
SB6	BUS5A + BUS6A + BUS3A
SB5	1
CCF	BUS5A * BUS2A * BUS6A + SB=F + INIT=LOCCW + INIT=LOCCWA
CC3	BUS5A * BUS2A + BUS5A * BUS6A + BUS2A * BUS6A
CC2	BUS5A + BUS6A + BUS2A
CC1	1

TABLE 3.2-1 IPE SYSTEMS		
System	IPPSS Section	UFSAR Section
Accumulators (ACS)	1.5.2.3.3	6.2.2.3.1
Auxiliary Feedwater System (AFS)	1.5.2.3.9	10.2.6.3
Component Cooling System (CCW)	1.5.2.3.7	9.3.1.2.1
Containment Spray System (CSS)	1.5.2.3.5	6.3.3.1
Electric Power System (EPS)	1.5.2.2.1	8.2
Fan Cooler Units (FCU)	1.5.2.3.6	6.4.2
High Pressure Injection System (HPIS)	1.5.2.3.1	6.2.2.1
Low Pressure Injection System (LPIS)	1.5.2.3.2	9.3.1.2.2
Main Steam Function (MSF)	(a)	10.2.1
Reactor Coolant System (RCS)	1.3.3.8,9,11[b]	4.3
Reactor Protection System (RPS)	1.5.2.2.2	7.3.2.2
Recirculation System (RSS)	1.5.2.3.4	6.2.2.1.2
Safeguards Actuation System (SAS)	1.5.2.2.3	7.2.5
Service Water System (SWS)	1.5.2.3.8	9.6.1
Offsite Power Recovery (OPR)	1.3.2.2	8.2.1[c]
EDG Building Ventilation (VENT)	(a)	(d)

(a) The functions and/or equipment represented by these systems in the IPE is new or significantly changed from the original IPPSS
(b) Addresses Seal LOCA and PORV "bleed" and ATWS pressure relief operation
(c) Addresses normal offsite power system
(d) Not specifically addressed

TABLE 3.2-2a

ACS SPLIT FRACTIONS

Split Fraction	Definition
AS1	Accumulator system.
ASF	Guaranteed failure of the accumulator system.

TABLE 3.2-2b

ACS CAUSE TABLE

AS1	Accumulator System
1.139E-03	Accumulator system response
1.139E-03	Hardware contribution
ASF	Accumulator System - Guaranteed failure
1.000E+00	Guaranteed failure

TABLE 3.2-2(c)
ACS EQUATION FILE

```
AS1    1 AS1TOP= 3 * ACCUM                    $ Accumulator system - total
AS1    2 ACCUM = 2 * CHVLV + MOVREF           $   Single accumulator
AS1    3 CHECKV= 2 * CHVLV                    $ Two check valves--series 895 and 897
AS1    4 MOVREF= MOVLV * TEST_I               $ Single MOV (normally open)--series 894
AS1      TEST_I= 13140 / 2                    $  Test Interval
AS1      CHVLV = IPV02D                       $  Check valve failure
AS1      MOVLV = IPV01T                       $   MOV fails to transfer
ASF    1 ASFTOP= 1.00                         $ Guaranteed failure of ACS system
```

TABLE 3.2-3a

AFS SPLIT FRACTIONS

Split Fraction	Definition
L11	AFW system normal response, all power available.
L12	AFW system normal response - power lost to 1 bus.
L13	AFW system normal response - no AC power.
L14	AFW system ATWS Core Cooling Rec- power available
L15	AFW system ATWS Core Cooling Rec-power lost 1 bus
L16	AFW system ATWS Core Cooling Rec. - no AC power
L1F	AFW system Guaranteed Failure - ATWS response.
L17	AFW system ATWS <40% all power available
L18	AFW system ATWS <40 power lost to 1 bus
L19	AFW system ATWS <40 no ac power
L1A	AFW system ATWS >40% All Power Available

TABLE 3.2-3b

AFS CAUSE TABLE

L11	**Auxiliary Feedwater System normal response - All power available**
1.046E-04	AFS normal response - All power available
2.647E-05	Random hardware failure
9.127E-07	Water supply
5.322E-05	CST
1.273E-02	CWST
2.556E-05	Pump trains
6.102E-13	Paths
1.186E-05	Maintenance
2.358E-06	Maintenance of turbine driven pump 22
4.752E-06	Maintenance of motor driven pump 21
4.752E-06	Maintenance of motor driven pump 23
6.773E-07	Test unavailability
2.105E-07	Test of turbine driven pump 22
2.334E-07	Test of motor driven pump 21
2.334E-07	Test of motor driven pump 23
1.124E-05	Operator error contribution
5.433E-05	Common cause contribution
L12	**Auxiliary Feedwater System normal response - Loss of one bus**
1.821E-03	AFS normal response - Loss of one bus (6A)
1.389E-03	Random hardware failure
9.127E-07	Water supply
1.389E-03	Pump trains
2.369E-10	Paths
3.992E-04	Maintenance
4.643E-05	Maintenance of turbine driven pump 22
3.527E-04	Maintenance of motor driven pump 21
2.147E-05	Test unavailability
4.165E-06	Test of turbine driven pump 22
1.730E-05	Test of motor driven pump 21
1.124E-05	Operator error contribution
1.466E-07	Common cause contribution

TABLE 3.2-3b

AFS CAUSE TABLE
(continued)

L13	**Auxiliary Feedwater System normal response - no AC power**
7.857E-02	AFS normal response - no AC power
7.577E-02	Random hardware failure
9.127E-07	Water supply
7.577E-02	Pump trains
2.071E-08	Paths
2.551E-03	Maintenance
2.283E-04	Test unavailability
1.980E-05	Operator error contribution
7.894E-06	Common cause contribution
L14	**Auxiliary Feedwater System - Core Cooling Recovery - All buses available**
4.871E-03	AFS - Core Cooling Recovery - All buses available
3.990E-03	Random hardware failure
9.127E-07	Water supply
3.825E-03	Pump trains
1.643E-04	Paths
8.251E-04	Maintenance
9.247E-05	Maintenance of turbine driven pump 22
3.663E-04	Maintenance of motor driven pump 21
3.663E-04	Maintenance of motor driven pump 23
4.424E-05	Test unavailability
8.296E-06	Test of turbine driven pump 22
1.797E-05	Test of motor driven pump 21
1.797E-05	Test of motor driven pump 23
1.124E-05	Operator error contribution
3.062E-09	Common cause contribution

TABLE 3.2-3b

AFS CAUSE TABLE
(continued)

L15 Auxiliary Feedwater System - Core Cooling Recovery - One bus unavailable

1.089E-01	AFS - Core Cooling Recovery - One bus unavailable
1.061E-01	Random hardware failure
9.127E-07	Water supply
1.030E-01	Pump trains
3.095E-03	Paths
2.564E-03	Maintenance
2.551E-03	Maintenance of turbine driven pump 22
1.364E-05	Maintenance of motor driven pump 21
2.290E-04	Test unavailability
2.283E-04	Test of turbine driven pump 22
6.709E-07	Test of motor driven pump 21
1.124E-05	Operator error contribution

L16 Auxiliary Feedwater System - Core Cooling Recovery - no AC power

1.118E-01	AFS - Core Cooling Recovery - no AC power
2.930E-01	Random hardware failure
9.127E-07	Water supply
1.030E-01	Pump trains
6.026E-03	Paths
2.913E-03	Maintenance
2.283E-04	Test unavailability
1.980E-05	Operator error contribution

L17 Auxiliary Feedwater System - ATWS Response (< 40% power) - All power available.

1.244E-04	AFS Response- ATWS < 40% - All power available.
3.233E-05	Hardware Contribution
6.717E-05	Contribution from common cause
1.298E-05	Contribution from maintenance
6.773E-07	Contribution from testing

TABLE 3.2-3b

AFS CAUSE TABLE
(continued)

L18	Auxiliary Feedwater System - ATWS Response (< 40% power) - Loss of one bus
2.231E-03	AFS Response- ATWS < 40% - Loss of one bus
1.712E-03	Contribution from hardware
1.466E-07	Contribution from common cause
4.821E-04	Contribution from maintenance
2.555E-05	Contribution from testing
L19	Auxiliary Feedwater System - ATWS Response (< 40% power) - No AC Power
9.646E-02	AFS Response - ATWS < 40% - No AC Power
9.366E-02	Contribution from hardware
7.894E-06	Contribution from common cause
2.551E-03	Contribution from maintenance
2.283E-04	Contribution from testing
L1A	Auxiliary Feedwater System - ATWS Response (> 40% power) - All Power Available
4.629E-02	AFS Response - ATWS > 40% - all power available.
3.654E-02	Hardware contribution
9.481E-03	Maintenance contribution
9.289E-03	Pump Maintenance
L1F	Guaranteed failure AFW system - Core Cooling Recovery
1.000E 00	Guaranteed failure AFW system - Core Cooling Recovery

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L11      1 L11TOP= L11_H + L11_M + L11_T + L11_C + OPERRR             $ AF System Total - All power available
L11      2 HDWR  = L11_H                                              $  Random hardware failure
L11      3 SUPLY = SUPPLY                                             $   Water supply
L11      4 TANKCS= CSTANK                                             $    Condensate storage tank
L11      5 TANKCW= CWTANK                                             $    City water storage tank
L11      6 PUMPS = PUMPSA                                             $   Pump supply paths
L11      7 PATHS = PATHSA                                             $   Pump discharge paths
L11      8 MAINT = L11_M                                              $  Maintenance
L11      9 MAINT2= PMP22M                                             $ Maintenance of turbine driven pump 22
L11     10 MAINT1= PMP21M                                             $   Maintenance of motor driven pump 21
L11     11 MAINT3= PMP23M                                             $   Maintenance of motor driven pump 23
L11     12 TEST  = L11_T                                              $  Test unavailability
L11     13 TEST22= PMP22T                                             $ Test of turbine driven pump 22
L11     14 TEST21= PMP21T                                             $   Test of motor driven pump 21
L11     15 TEST23= PMP23T                                             $   Test of motor driven pump 23
L11     16 OPEROR= OPERRR                                             $  Operator error - testing
L11     17 TOTCC = L11_C                                              $  Common cause total
L11     18 L11_H = SUPPLY + (1 - CSTANK)*PUMPSA + PATHSA + CSTANK*PUMCSA   $  Random hardware failure
L11     19 PUMPSA= PMP21*PMP22*PMP23 + PMP_1A + PMP_2A + PMP_3A + OTHERA   $     Pump paths
L11     20 PMP_1A= PMP21 * (PMP11A + PMP12A+PMP13A+PMP14A+PMP15A+PMP16A)   $     Pump paths
L11     21 PMP_3A= PMP23 * (PMP31A + PMP32A+PMP33A+PMP34A+PMP35A+PMP36A)   $     Pump paths
L11     22 PMP_2A= PMP22 * (PMP2AA + PMP2BA+PMP2CA+PMP2DA+PMP2EA+PMP2FA)   $     Pump paths
L11     23 PUMCSA= PMC21*PMC22*PMC23 + PMC_1A + PMC_2A + PMC_3A + OTHECA   $     Pump paths
L11     24 PMC_1A= PMC21* (PMP11A + PMP12A+PMP13A+PMP14A+PMP15A+PMP16A)    $     Pump paths
L11     25 PMC_3A= PMC23 * (PMP31A + PMP32A+PMP33A+PMP34A+PMP35A+PMP36A)   $     Pump paths
L11     26 PMC_2A= PMC22*(PMP2AA+PMP2BA+PMP2CA+PMP2DA+PMP2EA+PMP2FA)       $     Pump paths
L11     27 L11_C = CSTANK*CC5 + CC1 + CC2 + CC3 + CC4 + PTHACC        $    Common Cause
L11     28 CC5   = D3AV * (PMC21+ PMC22 + PMC23) + G3AV               $    Common Cause
L11     29 CC1   = CCPUMP * PMP22                                     $    Common Cause
L11     30 CC2   = CCPUMP * (OTHR4A + OTHR5A + OTHR6A + OTHR7A + OTHR8A)   $    Common Cause
L11     31 CC3   = CCPUMP * (OTH5AC + OTH6AC + OTH7AC + OTH8AC)       $    Common Cause
L11     32 CC4   = PMP21 * PMP23 * (OTH5AC + OTH6AC + OTH7AC + OTH8AC)     $    Common Cause
L11     33 OTHERA= PMP22 * (PMP21 * OTHR1A+ PMP23 * OTHR2A) + OTHR3A  $    Flow paths to steam generator
L11     34 OTHECA= PMC22 * (PMC21 * OTHR1A+ PMC23 * OTHR2A) + OTHC3A  $    Flow paths to steam generator
L11     35 OTHR1A= SG23 + SG24 + MP23 + MP24                          $    Flow paths
L11     36 OTHR2A= SG21 + SG22 + MP21 + MP22                          $    Flow paths
L11     37 OTHR3A= PMP21 * PMP23 * (OTHR4A+OTHR5A+OTHR6A+OTHR7A+OTHR8A)    $    Flow paths
L11     38 OTHC3A= PMC21 * PMC23 * (OTHR4A+OTHR5A+OTHR6A+OTHR7A+OTHR8A)    $    Flow paths
L11     39 OTHR4A= TP24 * GP_A + TP23 * GP_B + TP22 * GP_C + TP21 * GP_D   $    Flow paths
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L11    40 OTHR5A= TP23*TP24*GP_E + TP22*TP24*GP_F                        $    Flow paths
L11    41 OTH5AC= D4AV * GP_E + D4AV * GP_F                              $    Flow paths
L11    42 OTHR6A= TP22*TP23*GP_G + TP21*TP24*GP_H                        $    Flow paths
L11    43 OTH6AC= D4AV * GP_G + D4AV * GP_H                              $    Flow paths
L11    44 OTHR7A= TP21*TP23*GP_I + TP21*TP22*GP_J                        $    Flow paths
L11    45 OTH7AC= D4AV * GP_I + D4AV * GP_J                              $    Flow paths
L11    46 OTHR8A= TP21 * TP22 * (TP23+TP24) + (TP21+TP22)*TP23*TP24      $    Flow paths
L11    47 OTH8AC= D4AV * (TP23+TP24) + D4AV * (TP21 + TP22)              $    Flow paths
L11    48 PATHSA= PATH1A + PATH2A + PATH3A+PATH4A+PATH5A+PATH6A+PATH7A   $    Flow paths
L11    49 PTHACC= PTH4AC+PTH5AC+PTH6AC+PTH7AC+PTH8AC+PTH9AC+PTHDCC       $    Flow paths
L11    50 PATH1A= SG21 * SG22 * (SG23+SG24) + (SG21+SG22) * SG23 * SG24  $    Flow paths
L11    51 PATH2A= MP24 * TP24 * GP_A + MP23 * TP23 * GP_B                $    Flow paths
L11    52 PATH3A= MP22 * TP22 * GP_C + MP21 * TP21 * GP_D                $    Flow paths
L11    53 PATH4A= MP23 * TP23 * MP24 * TP24 * GP_E + PATH8A+ PATH9A      $    Flow paths
L11    54 PTH4AC= MP23 * MP24 * D4AV * GP_E + PTH8AC + PTH9AC            $    Flow paths
L11    55 PATH5A= MP22 * TP22 * MP24 * TP24 * GP_F + PATHAA + PATHBA     $    Flow paths
L11    56 PTH5AC= MP22 * MP24 * D4AV * GP_F                              $    Flow paths
L11    57 PATH6A= MP22 * TP22 * MP23 * TP23 * GP_G + PATHCA + PATHDA     $    Flow paths
L11    58 PTH6AC= MP22 * MP23 * D4AV * GP_G                              $    Flow paths
L11    59 PATH7A= MP21 * TP21 * MP24 * TP24 * GP_H                       $    Flow paths
L11    60 PTH7AC= MP21 * MP24 * D4AV * GP_H                              $    Flow paths
L11    61 PATH8A= MP21 * TP21 * MP23 * TP23 * GP_I                       $    Flow paths
L11    62 PTH8AC= MP21 * MP23 * D4AV * GP_I                              $    Flow paths
L11    63 PATH9A= MP21 * TP21 * MP22 * TP22 * GP_J                       $    Flow paths
L11    64 PTH9AC= MP21 * MP22 * D4AV * GP_J                              $    Flow paths
L11    65 PATHAA= MP22 * TP22 * MP23 * TP23 * MP24 * TP24                $    Flow paths
L11    66 PATHBA= MP21 * TP21 * MP23 * TP23 * MP24 * TP24                $    Flow paths
L11    67 PATHCA= MP21 * TP21 * MP22 * TP22 * MP24 * TP24                $    Flow paths
L11    68 PATHDA= MP21 * TP21 * MP22 * TP22 * MP23 * TP23                $    Flow paths
L11    69 PTHDCC= G4AV * (MP22*MP23*MP24 + MP21*MP23*MP24 + CCXX1)       $    Flow paths
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L11    70 CCXX1 = MP21*MP22*MP24 + MP21*MP22*MP23                  $   Flow paths
L11    71 L11_M = PMP21M + PMP22M + PMP23M                          $ Maintenance
L11    72 PMP22M= TPMP_M * (PP22M + PMP21 * PMP23 + CCPUMP)         $  Maintenance, turbine driven pump 22
L11    73 PP22M = PMP2AA+ PMP2BA+ PMP2CA+ PMP2DA+ PMP2EA+ PMP2FA    $   Maintenance
L11    74 PMP21M= MPMP_M * (PP21M + PMP22 * PMP23)                  $  Maintenance of motor driven pump 21
L11    75 PP21M = PMP1TA+ PMP12A+ PMP13A+ PMP14A+ PMP15A+ PMP16A    $   Maintenance
L11    76 PMP23M= MPMP_M * (PP23M + PMP21 * PMP22)                  $  Maintenance of motor driven pump 23
L11    77 PP23M = PMP3TA+ PMP32A+ PMP33A+ PMP34A+ PMP35A+ PMP36A    $    Maintenance
L11    78 L11_T = PMP21T + PMP22T + PMP23T                          $ Test unavailability
L11    79 PMP22T= PMP_T * (PP22T + PMP21 * PMP23 + CCPUMP)          $ Test of turbine driven pump 22
L11    80 PP22T = PMP2AA+ PMP2BA+ PMP2CA+ PMP2DA+ PMP2EA+ PMP2FA    $   Test
L11    81 PMP21T= PMP_T * (PP21T + PMP22 * PMP23)                   $  Test of motor driven pump 21
L11    82 PP21T = PMPT1A+ PMP12A+ PMP13A+ PMP14A+ PMP15A+ PMP16A    $   Test
L11    83 PMP23T= PMP_T * (PP23T + PMP21 * PMP22)                   $  Test of motor driven pump 23
L11    84 PP23T = PMP31A+ PMP32A+ PMP33A+ PMP34A+ PMP35A+ PMP36A    $  Test
L11    85 PMP11A= TP21*GP_D + TP22*GP_C + (TP22*TP24 + D4AV)*MP24*GP_F  $ Hardware failures
L11    86 PMP12A= (TP22*TP23+D4AV)*MP23*GP_G+(TP21*TP24+D4AV)*MP24*GP_H $ Hardware failures
L11    87 PMP13A= (TP21*TP23 +D4AV)*MP23*GP_I + (TP21*TP22 + D4AV)*GP_J $ Hardware
L11    88 PMP14A= TP22 * MP23 * TP23 * MP24 * TP24                  $ Hardware
L11    89 PMP15A= TP21 * MP23 * TP23 * MP24 * TP24                  $ Hardware
L11    90 PMP16A= TP21 * TP22 * MP23*TP23 + TP21*TP22*MP24*TP24 + PP16C $ Hardware
L11    91 PP16C = G4AV * (MP23 + MP24)                              $ Hardware
L11    92 PMP31A= TP24 * GP_A + TP23 * GP_B + (TP23*TP24 + D4AV) * GP_E $ Hardware
L11    93 PMP32A= (TP22*TP24+D4AV)*MP22*GP_F+(TP22*TP23+D4AV)*MP22*GP_G $ Hardware
L11    94 PMP33A= (TP21*TP24+D4AV)*MP21*GP_H+(TP21*TP23+D4AV)*MP21*GP_I $ Hardware
L11    95 PMP34A= MP21 * TP21 * MP22 * TP22 * TP23                  $ Hardware
L11    96 PMP35A= MP21 * TP21 * MP22 * TP22 * TP24                  $ Hardware
L11    97 PMP36A= MP21 * TP21 * TP23*TP24 + MP22*TP22*TP23*TP24 + PP36C $ Hardware
L11    98 PP36C = G4AV * (MP21 + MP22)                              $ Hardware
L11    99 PMP2AA= MP24 * GP_A + MP23 * GP_B + MP22 * GP_C + MP21 * GP_D $ Hardware
L11   100 PMP2BA= MP23*MP24*GP_E + MP22*MP24*GP_F                   $ Hardware
L11   101 PMP2CA= MP22*MP23*GP_G + MP21*MP24*GP_H                   $ Hardware
L11   102 PMP2DA= MP21*MP23*GP_I + MP21*MP22*GP_J                   $ Hardware
L11   103 PMP2EA= MP22 * MP23 * MP24 + MP21 * MP23 * MP24           $ Hardware
L11   104 PMP2FA= MP21 * MP22 * MP24 + MP21 * MP22 * MP23           $ Hardware
L11   105 PMC21 = CT25 + PV1187 + MP21S + BFD34 + MP21R             $ Hardware
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L12    1 L12TOP= L12_H + L12_M + L12_T + L12_C + OPERRR               $ AFS Total-Loss of bus (6A)
L12    2 HDWR  = L12_H                                                 $  Random hardware failure
L12    3 SUPLY = SUPPLY                                                $   Water supply
L12    4 PUMPS = PUMPSB                                                $    Pump trains
L12    5 PATHS = PATHSB                                                $    Paths
L12    6 MAINT = L12_M                                                 $  Maintenance
L12    7 MAINT2= PP22MB                                                $ Maintenance of turbine driven pump 22
L12    8 MAINT1= PP21MB                                                $   Maintenance of motor driven pump 21
L12    9 TEST  = L12_T                                                 $  Test unavailability
L12   10 TEST2 = PP22TB                                                $ Test of turbine driven pump 22
L12   11 TEST1 = PP21TB                                                $   Test of motor driven pump 21
L12   12 OPEROR= OPERRR                                                $  Operator error - testing
L12   13 TOTCC = L12_C                                                 $. Common Cause Contribution - Total
L12   14 L12_H = SUPPLY + (1 - CSTANK)*PUMPSB + PATHSB + CSTANK*PUMCSB $  Hardware Contribution - Total
L12   15 PUMPSB= PMP22 * PMP21 + PMP22 * OTHR1B + PMP21 * OTHR2B       $   Pump Stand-By failure
L12   16 PUMCSB= PMC22*PMC21+ PMC22 * OTHR1B +PMC21* OTHR2B            $   Pump Stand-By failure
L12   17 L12_C = CSTANK*(CC12 +PMC21*OTH2BC) + PTHBCC + L12XXX         $  Common Cause model
L12   18 L12XXX= (1 - CSTANK)*PMP21*OTH2BC                             $    Common Cause
L12   19 CC12  = D3AV + G3AV                                           $    Common Cause
L12   20 PATHSB= PATH1B+PATH2B+PATH3B+PATH4B+PATH5B+PATH6B+PATH7B      $  Hardware
L12   21 PTHBCC= PTH3BC + PTH4BC + PTH5BC + PTH6BC + PTH7BC            $   Hardware
L12   22 PATH1B= SG21 * SG22 * (SG23+SG24) + (SG21+SG22) * SG23 * SG24 $   Hardware
L12   23 PATH2B= TP24*GP_A + TP23 * GP_B + MP22 * TP22 * GP_C + PATH8B $   Hardware
L12   24 PATH3B= MP21 * TP21 * GP_D + TP23 * TP24 * GP_E               $   Hardware
L12   25 PTH3BC= D4AV * GP_E                                           $   Hardware
L12   26 PATH4B= MP22 * TP22 * TP24 * GP_F + MP22 * TP22 * TP23 * GP_G $   Hardware
L12   27 PTH4BC= D4AV * MP22 * GP_F + D4AV * MP22 * GP_G               $   Hardware
L12   28 PATH5B= MP21 * TP21 * TP24 * GP_H + MP21 * TP21 * TP23 * GP_I $   Hardware
L12   29 PTH5BC= D4AV * MP21 * GP_H + D4AV * MP21 * GP_I               $   Hardware
L12   30 PATH6B= MP21 * TP21 * MP22 * TP22 * GP_J                      $   Hardware
L12   31 PTH6BC= D4AV * MP21 * MP22 * GP_J                             $   Hardware
L12   32 PATH7B= MP22 * TP22 * TP23 * TP24 + MP21 * TP21 * TP23 * TP24 $   Hardware
L12   33 PTH7BC= G4AV * (MP21 + MP22)                                  $   Hardware
L12   34 PATH8B= MP21 * TP21 * MP22 * TP22 * (TP23 + TP24)             $   Hardware
L12   35 L12_M = PP21MB + PP22MB                                       $  Maintenance
L12   36 PP22MB= TPMP_M * (PMP21 + OTHR1B)                             $ Maintenance of turbine driven pump 22
L12   37 PP21MB= MPMP_M * (PMP22 + OTHR2B + OTH2BC)                    $   Maintenance of motor driven pump 21
L12   38 L12_T = PP21TB + PP22TB                                       $  Test unavailability
L12   39 PP22TB= PMP_T * (PMP21 + OTHR1B)                              $ Test of turbine driven pump 22
L12   40 PP21TB= PMP_T * (PMP22 + OTHR2B + OTH2BC)                     $   Test of motor driven pump 21
L12   41 OTHR1B= SG21 + SG22 + MP21 + MP22                             $     Flow path
L12   42 OTHR2B= OTHR3B+ OTHR4B+ OTHR5B+ OTHR6B+ OTHR7B                $     Flow path
L12   43 OTH2BC= D4AV*(GP_E + GP_F + GP_G + GP_H + GP_I + GP_J) + G4AV $     Flow path
L12   44 OTHR3B= TP24 * GP_A + TP23 * GP_B + TP22 * GP_C + TP21 * GP_D $     Flow path
L12   45 OTHR4B= TP23*TP24 * GP_E + TP22*TP24 * GP_F                   $     Flow path
L12   46 OTHR5B= TP22*TP23 * GP_G + TP21*TP24 * GP_H                   $     Flow path
L12   47 OTHR6B= TP21*TP23 * GP_I + TP21*TP22 * GP_J                   $     Flow path
L12   48 OTHR7B= TP21*TP22*(TP23+TP24) + (TP21+TP22)*TP23*TP24         $     Flow path
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L13   1 L13TOP= L13_H + L13_M + L13_T + L13_C + OPERRR              $ AF System Total - No AC power
L13   2 HDWR  = L13_H                                              $  Random hardware failure
L13   3 SUPLY = SUPPLY                                             $   Water supply
L13   4 PUMPS = PMP22                                              $   Pump trains
L13   5 PATHS = PATHSC                                             $   Paths
L13   6 L13_M = TPMP_M                                             $  Maintenance
L13   7 L13_T = PMP_T                                              $  Test unavailability
L13   8 L13_OP= OPERR                                              $  Operator error - testing
L13   9 TOTCC = L13_C                                              $  Common Cause
L13  11 L13_H = SUPPLY + (1 - CSTANK)*PUMPSC + PATHSC + CSTANK*PUMCSC $  Hardware
L13  12 PUMPSC= PMP22                                              $   Pump trains
L13  13 PUMCSC= PMC22                                              $   Pump trains
L13  14 PATHSC= PATH1C + PATH2C + PATH3C+PATH4C+PATH5C+PATH6C+PATH7C $     Paths
L13  15 L13_C = PTH3CC + PTH4CC + PTH5CC + PTH6CC                  $     Common Cause
L13  16 PATH1C= SG21 * SG22 * (SG23+SG24) + (SG21+SG22) * SG23 * SG24 $     Flow path
L13  17 PATH2C= TP24 * GP_A + TP23 * GP_B + TP22 * GP_C + TP21 * GP_D $     Flow path
L13  18 PATH3C= TP23*TP24 * GP_E + TP22*TP24 * GP_F                $     Flow path
L13  19 PTH3CC= D4AV * (GP_E + GP_F)                               $     Flow path
L13  20 PATH4C= TP22 * TP23 * GP_G + TP21 * TP24 * GP_H            $     Flow path
L13  21 PTH4CC= D4AV * (GP_G + GP_H)                               $     Flow path
L13  22 PATH5C= TP21 * TP23 * GP_I + TP21 * TP22 * GP_J            $     Flow path
L13  23 PTH5CC= D4AV * (GP_I + GP_J)                               $     Flow path
L13  24 PATH6C= (TP21 + TP22) * TP23 * TP24                        $     Flow path
L13  25 PTH6CC= G4AV                                               $     Flow path
L13  26 PATH7C= TP21 * TP22 * (TP23 + TP24)                        $     Flow path
L13  27 L13_M = TPMP_M                                             $  Maintenance
L13  28 L13_T = PMP_T                                              $  Test unavailability
L14   1 L14TOP= L14_H + L14_M + L14_T + L14_C + OPERRR              $ AF system total Core Cooling Recovery, All power available
L14   2 HDWR  = L14_H                                              $  Random hardware failure
L14   3 SUPLY = SUPPLY                                             $  Water supply
L14   4 PUMPS = PUMPSD                                             $  Pump paths
L14   5 PATHS = PATHSD                                             $  SG flow paths
L14   6 MAINT = L14_M                                              $  Maintenance
L14   7 MAINT2= PP22MD                                             $ Maintenance of turbine driven pump 22
L14   8 MAINT1= PP21MD                                             $   Maintenance of motor driven pump 21
L14   9 MAINT3= PP23MD                                             $   Maintenance of motor driven pump 23
L14  10 TEST  = L14_T                                              $  Test unavailability
L14  11 TEST2 = PP22TD                                             $ Test of turbine driven pump 22
L14  12 TEST1 = PP21TD                                             $   Test of motor driven pump 21
L14  13 TEST3 = PP23TD                                             $   Test of motor driven pump 23
L14  14 OPEROR= OPERRR                                             $ Operator error - testing
L14  15 TOTCC = L14_C                                              $ Common Cause
L14  17 L14_H = SUPPLY + (1 - CSTANK)*PUMPSD + PATHSD + CSTANK*PUMCSD $ Random hardware failure
L14  18 PUMPSD= PMP22A * (PMP21 + PMP23) + PMP_1D + PMP_2D + PMP_3D $   Pump paths
L14  19 PMP_1D= PMP21 * (TP21 + TP22)                              $    Hardware
L14  20 PMP_3D= PMP23 * (TP23 + TP24)                              $    Hardware
L14  21 PMP_2D= PMP22A * (MP21 + MP22 + MP23 + MP24)               $    Hardware
L14  22 PUMCSD= PMC22*(PMC21+PMC23) + PMC_1D + PMC_2D + PMC_3D      $ Pump paths
L14  23 L14_C = CSTANK * CC14                                      $    Common Cause
L14  24 CC14  = 2 * D3AV + G3AV                                    $    Common Cause
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L14   25 PMC_1D= PMC21 * (TP21 + TP22)                              $   Hardware
L14   26 PMC_3D= PMC23 * (TP23 + TP24)                              $   Hardware
L14   27 PMC_2D= PMC22 * (MP21 + MP22 + MP23 + MP24)                $   Hardware
L14   28 PATHSD= SG21 + SG22 + SG23 + SG24 + PATH1D                 $   SG flow paths
L14   29 PATH1D= MP21 * TP21 + MP22 * TP22 + MP23 * TP23 + MP24 * TP24   $    Flow path
L14   30 L14_M = PP21MD + PP22MD + PP23MD                           $  Maintenance
L14   31 PP22MD= TPMP_M * (PMP21 + PMP23 + MP21 + MP22 + MP23 + MP24)    $ Maintenance of turbine driven pump 22
L14   32 PP21MD= MPMP_M * (PMP22 + TP21 + TP22)                     $   Maintenance of motor driven pump 21
L14   33 PP23MD= MPMP_M * (PMP22 + TP23 + TP24)                     $   Maintenance of motor driven pump 23
L14   34 L14_T = PP21TD + PP22TD + PP23TD                           $  Test unavailability
L14   35 PP22TD= PMP_T * (PMP21 + PMP23 + MP21 + MP22 + MP23 + MP24)     $ Test of turbine driven pump 22
L14   36 PP21TD= PMP_T * (PMP22 + TP21 + TP22)                      $   Test of motor driven pump 21
L14   37 PP23TD= PMP_T * (PMP22 + TP23 + TP24)                      $   Test of motor driven pump 23
L15    1 L15TOP= L15_H + L15_M + L15_T + OPERRR                     $ AF system total (Core Cooling Recovery) Loss of one bus (6A)
L15    2 HDWR  = L15_H                                              $  Random hardware failure
L15    3 SUPLY = SUPPLY                                             $   Water supply
L15    4 PUMPS = PUMPSE                                             $    Pump trains
L15    5 PATHS = PATHSE                                             $    Paths
L15    6 MAINT = L15_M                                              $  Maintenance
L15    7 MAINT2= PP22ME                                             $ Maintenance of turbine driven pump 22
L15    8 MAINT1= PP21ME                                             $   Maintenance of motor driven pump 21
L15    9 TEST  = L15_T                                              $  Test unavailability
L15   10 TEST2 = PP22TE                                             $ Test of turbine driven pump 22
L15   11 TEST1 = PP21TE                                             $   Test of motor driven pump 21
L15   12 OPEROR= OPERR                                              $  Operator error - testing
L15   13 L15   = L15_H + L15_M + L15_T + OPERRR                     $ AF system total (Core Cooling Recovery) Loss of one bus (6A)
L15   14 L15_H = SUPPLY + (1 - CSTANK)*PUMPSE + PATHSE + CSTANK*PUMCSE   $  Random hardware failure
L15   15 PUMPSE= PMP22A + PMP21 * (TP21 + TP22)                     $    Pump trains
L15   16 PUMCSE= PMC22 + PMC21 * (TP21 + TP22)                      $    Pump trains
L15   17 PATHSE= SG21 + SG22 + SG23 + SG24 + TP23 + TP24 + PATH1E   $    Flow path
L15   18 PATH1E= MP21 * TP21 + MP22 * TP22                          $    Flow path
L15   19 L15_M = PP21ME + PP22ME                                    $  Maintenance
L15   20 PP22ME= TPMP_M                                             $ Maintenance of turbine driven pump 22
L15   21 PP21ME= MPMP_M * (TP21 + TP22)                             $   Maintenance of motor driven pump 21
L15   22 L15_T = PP21TE + PP22TE                                    $  Test unavailability
L15   23 PP22TE= PMP_T                                              $ Test of turbine driven pump 22
L15   24 PP21TE= PMP_T * (TP21 + TP22)                              $   Test of motor driven pump 21
L16    1 L16TOP= L16_H + L16_M + L16_T + OPERRR                     $ AF system total Core Cooling Recovery - No AC power
L16   10 L16_H = SUPPLY + (1 - CSTANK)*PUMPSF + PATHSF + CSTANK*PUMCSF   $  Random hardware failure
L16   14 L16_M = TPMP_M                                             $  Maintenance
L16   15 L16_T = PMP_T                                              $  Test unavailability
L16    3 SUPLY = SUPPLY                                             $   Water supply
L16    4 PUMPS = PUMPSF                                             $   Pump trains
L16    5 PATHS = PATHSF                                             $   Paths
L16    8 OPEROR= OPERRR                                             $  Operator error - testing
L16   11 PUMPSF= PMP22A                                             $   Pump trains
L16   12 PUMCSF= PMC22                                              $   Pump trains
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L16   13 PATHSF= SG21 + SG22 + SG23 + SG24 + TP21 + TP22 + TP23 + TP24    $   Paths
L17    1 L17TOP= L17_H + L17_M + L17_T + L17_C + OPERRR                   $ AFW System Total- ATWS < 40% power) - All power available
L17    2 L17_H = SUPPLY + (1 - CSTANK)*PUMPSA + PATHSA + CSTANK*PUMCSA    $  Random hardware failure
L17    3 PUMPSA= PMP21*PMP22B*PMP23 +PMP_1A + PMP_2A + PMP_3A + OTHERA    $     Pump paths
L17    4 PMP_1A= PMP21 * (PMP11A + PMP12A+PMP13A+PMP14A+PMP15A+PMP16A)    $     Pump paths
L17    5 PMP_3A= PMP23 * (PMP31A + PMP32A+PMP33A+PMP34A+PMP35A+PMP36A)    $     Pump paths
L17    6 PMP_2A= PMP22 * (PMP2AA + PMP2BA+PMP2CA+PMP2DA+PMP2EA+PMP2FA)    $     Pump paths
L17    7 PUMCSA= PMC21*PMC22*PMC23 + PMC_1A + PMC_2A + PMC_3A + OTHECA    $     Pump paths
L17    8 PMC_1A= PMC21 * (PMP11A + PMP12A+PMP13A+PMP14A+PMP15A+PMP16A)    $     Pump paths
L17    9 PMC_3A= PMC23 * (PMP31A + PMP32A+PMP33A+PMP34A+PMP35A+PMP36A)    $     Pump paths
L17   10 PMC_2A= PMC22*(PMP2AA+PMP2BA+PMP2CA+PMP2DA+PMP2EA+PMP2FA)        $     Pump paths
L17   11 L17_C = CSTANK*CC5 + CC1 + CC2 + CC3 + CC4 + PTHACC              $  Common cause
L17   12 CC5   = D3AV * (PMC21 + PMC22 + PMC23) + G3AV                    $    Common cause
L17   13 CC1   = CCPUMP * PMP22B                                          $    Common cause
L17   14 CC2   = CCPUMP * (OTHR4A + OTHR5A + OTHR6A + OTHR7A + OTHR8A)    $    Common cause
L17   15 CC3   = CCPUMP * (OTH5AC + OTH6AC + OTH7AC + OTH8AC)             $    Common cause
L17   16 CC4   = PMP21 * PMP23 * (OTH5AC + OTH6AC + OTH7AC + OTH8AC)      $    Common cause
L17   17 OTHERA= PMP22B* (PMP21 * OTHR1A+ PMP23 * OTHR2A) + OTHR3A        $   Flow paths to steam generator
L17   18 OTHECA= PMC22 * (PMC21 * OTHR1A+ PMC23 * OTHR2A) + OTHC3A        $   Flow paths to steam generator
L17   19 OTHR1A= SG23 + SG24 + MP23 + MP24                                $    Flow path
L17   20 OTHR2A= SG21 + SG22 + MP21 + MP22                                $    Flow path
L17   21 OTHR3A= PMP21 * PMP23 * (OTHR4A+OTHR5A+OTHR6A+OTHR7A+OTHR8A)     $    Flow path
L17   22 OTHC3A= PMC21 * PMC23 * (OTHR4A+OTHR5A+OTHR6A+OTHR7A+OTHR8A)     $    Flow path
L17   23 OTHR4A= TP24 * GP_A + TP23 * GP_B + TP22 * GP_C + TP21 * GP_D    $    Flow path
L17   24 OTHR5A= TP23*TP24*GP_E + TP22*TP24*GP_F                          $    Flow path
L17   25 OTH5AC= D4AV * GP_E + D4AV * GP_F                                $    Flow path
L17   26 OTHR6A= TP22*TP23*GP_G + TP21*TP24*GP_H                          $    Flow path
L17   27 OTH6AC= D4AV * GP_G + D4AV * GP_H                                $    Flow path
L17   28 OTHR7A= TP21*TP23*GP_I + TP21*TP22*GP_J                          $    Flow path
L17   29 OTH7AC= D4AV * GP_I + D4AV * GP_J                                $    Flow path
L17   30 OTHR8A= TP21 * TP22 * (TP23+TP24) + (TP21+TP22)*TP23*TP24        $    Flow path
L17   31 OTH8AC= D4AV * (TP23+TP24) + D4AV * (TP21 + TP22)                $    Flow path
L17   32 PATHSA= PATH1A + PATH2A + PATH3A+PATH4A+PATH5A+PATH6A+PATH7A     $    Flow path
L17   33 PTHACC= PTH4AC+PTH5AC+PTH6AC+PTH7AC+PTH8AC+PTH9AC+PTHDCC         $    Flow path
L17   34 PATH1A= SG21 * SG22 * (SG23+SG24) + (SG21+SG22) * SG23 * SG24    $    Flow path
L17   35 PATH2A= MP24 * TP24 * GP_A + MP23 * TP23 * GP_B                  $    Flow path
L17   36 PATH3A= MP22 * TP22 * GP_C + MP21 * TP21 * GP_D                  $    Flow path
L17   37 PATH4A= MP23 * TP23 * MP24 * TP24 * GP_E + PATH8A+ PATH9A        $    Flow path
L17   38 PTH4AC= MP23 * MP24 * D4AV * GP_E + PTH8AC + PTH9AC              $    Flow path
L17   39 PATH5A= MP22 * TP22 * MP24 * TP24 * GP_F + PATHAA + PATHBA       $    Flow path
L17   40 PTH5AC= MP22 * MP24 * D4AV * GP_F                                $    Flow path
L17   41 PATH6A= MP22 * TP22 * MP23 * TP23 * GP_G + PATHCA + PATHDA       $    Flow path
L17   42 PTH6AC= MP22 * MP23 * D4AV * GP_G                                $    Flow path
L17   43 PATH7A= MP21 * TP21 * MP24 * TP24 * GP_H                         $    Flow path
L17   44 PTH7AC= MP21 * MP24 * D4AV * GP_H                                $    Flow path
L17   45 PATH8A= MP21 * TP21 * MP23 * TP23 * GP_I                         $    Flow path
```

TABLE 3.2-3(c)
AFS EQUATION FILE

L17	46	PTH8AC= MP21 * MP23 * D4AV * GP_I	$	Flow path
L17	47	PATH9A= MP21 * TP21 * MP22 * TP22 * GP_J	$	Flow path
L17	48	PTH9AC= MP21 * MP22 * D4AV * GP_J	$	Flow path
L17	49	PATHAA= MP22 * TP22 * MP23 * TP23 * MP24 * TP24	$	Flow path
L17	50	PATHBA= MP21 * TP21 * MP23 * TP23 * MP24 * TP24	$	Flow path
L17	51	PATHCA= MP21 * TP21 * MP22 * TP22 * MP24 * TP24	$	Flow path
L17	52	PATHDA= MP21 * TP21 * MP22 * TP22 * MP23 * TP23	$	Flow path
L17	53	PTHDCC= G4AV * (MP22*MP23*MP24 + MP21*MP23*MP24 + CCXX1)	$	Flow path
L17	54	CCXX1 = MP21*MP22*MP24 + MP21*MP22*MP23	$	Flow path
L17	55	L17_M = PMP21M + PMP22M + PMP23M	$	Maintenance
L17	56	PMP22M= TPMP_M * (PP22M + PMP21 * PMP23 + CCPUMP)	$	Maintenance of turbine driven pump 22
L17	57	PP22M = PMP2AA+ PMP2BA+ PMP2CA+ PMP2DA+ PMP2EA+ PMP2FA	$	Maintenance
L17	58	PMP21M= MPMP_M * (PP21M + PMP22B * PMP23)	$	Maintenance of motor driven pump 21
L17	59	PP21M = PMP11A+PMP12A+ PMP13A+ PMP14A+ PMP15A + PMP16A	$	Maintenance
L17	60	PMP23M= MPMP_M * (PP23M + PMP21 * PMP22)	$	Maintenance of motor driven pump 23
L17	61	PP23M = PMP31A+ PMP32A+ PMP33A+ PMP34A+ PMP35A+ PMP36A	$	Maintenance
L17	62	L17_T = PMP21T + PMP22T + PMP23T	$	Test unavailability
L17	63	PMP22T= PMP_T * (PP22T + PMP21 * PMP23 + CCPUMP)	$	Test of turbine driven pump 22
L17	64	PP22T = PMP2AA+ PMP2BA+ PMP2CA+ PMP2DA+ PMP2EA+ PMP2FA	$	Testing
L17	65	PMP21T= PMP_T * (PP21T + PMP22 * PMP23)	$	Test of motor driven pump 21
L17	66	PP21T = PMP11A+ PMP12A+ PMP13A+ PMP14A+ PMP15A+ PMP16A	$	Testing
L17	67	PMP23T= PMP_T * (PP23T + PMP21 * PMP22)	$	Test of motor driven pump 23
L17	68	PP23T = PMP31A+ PMP32A+ PMP33A+ PMP34A+ PMP35A+ PMP36A	$	Testing
L17	69	PMP11A= TP21*GP_D + TP22*GP_C + (TP22*TP24 + D4AV)*MP24*GP_F	$	Hardware failure
L17	70	PMP12A= (TP22*TP23+D4AV)*MP23*GP_G+(TP21*TP24+D4AV)*MP24*GP_H	$	Hardware
L17	71	PMP13A= (TP21*TP23 +D4AV)*MP23*GP_I + (TP21*TP22 + D4AV)*GP_J	$	Hardware
L17	72	PMP14A= TP22 * MP23 * TP23 * MP24 * TP24	$	Hardware
L17	73	PMP15A= TP21 * MP23 * TP23 * MP24 * TP24	$	Hardware
L17	74	PMP16A= TP21 * TP22 * MP23*TP23 + TP21*TP22*MP24*TP24 + PP16C	$	Hardware
L17	75	PP16C = G4AV * (MP23 + MP24)	$	Hardware
L17	76	PMP31A= TP24 * GP_A + TP23 * GP_B + (TP23*TP24 + D4AV) * GP_E	$	Hardware
L17	77	PMP32A= (TP22*TP24+D4AV)*MP22*GP_F+(TP22*TP23+D4AV)*MP22*GP_G	$	Hardware
L17	78	PMP33A= (TP21*TP24+D4AV)*MP21*GP_H+(TP21*TP23+D4AV)*MP21*GP_I	$	Hardware
L17	79	PMP34A= MP21 * TP21 * MP22 * TP22 * TP23	$	Hardware
L17	80	PMP35A= MP21 * TP21 * MP22 * TP22 * TP24	$	Hardware
L17	81	PMP36A= MP21 * TP21 * TP23*TP24 + MP22*TP22*TP23*TP24 + PP36C	$	Hardware
L17	82	PP36C = G4AV * (MP21 + MP22)	$	Hardware
L17	83	PMP2AA= MP24 * GP_A + MP23 * GP_B + MP22 * GP_C + MP21 * GP_D	$	Hardware
L17	84	PMP2BA= MP23*MP24*GP_E + MP22*MP24*GP_F	$	Hardware
L17	85	PMP2CA= MP22*MP23*GP_G + MP21*MP24*GP_H	$	Hardware
L17	86	PMP2DA= MP21*MP23*GP_I + MP21*MP22*GP_J	$	Hardware
L17	87	PMP2EA= MP22 * MP23 * MP24 + MP21 * MP23 * MP24	$	Hardware
L17	88	PMP2FA= MP21 * MP22 * MP24 + MP21 * MP22 * MP23	$	Hardware
L18	1	L18TOP= L18_H + L18_M + L18_T + L18_C + OPERRR	$	AFS total (ATWS<40%),loss of one bus (6A)
L18	2	L18_H = SUPPLY + (1 - CSTANK)*PUMPSB + PATHSB + CSTANK*PUMCSB	$	Random hardware failure
L18	3	PUMPSB= PMP22B * PMP21+ PMP22B* OTHR1B + PMP21 * OTHR2B	$	Pump stand-by failure
L18	4	PUMCSB= PMC22*PMC21 + PMC22 * OTHR1B + PMC21 * OTHR2B	$	Pump stand-by failure
L18	5	L18_C = CSTANK*(CC12 + PMC21*OTH2BC) + PTHBCC + L12XXX	$	Common Cause

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L18     6 L12XXX= (1 - CSTANK)*PMP21*OTH2BC                              $ Common Cause
L18     7 CC12  = D3AV + G3AV                                            $ Common Cause
L18     8 PATHSB= PATH1B+PATH2B+PATH3B+PATH4B+PATH5B+PATH6B+PATH7B       $   Hardware
L18     9 PTHBCC= PTH3BC + PTH4BC + PTH5BC + PTH6BC + PTH7BC             $   Hardware
L18    10 PATH1B= SG21 * SG22 * (SG23+SG24) + (SG21+SG22) * SG23 * SG24  $   Hardware
L18    11 PATH2B= TP24*GP_A + TP23 * GP_B + MP22 * TP22 * GP_C + PATH8B  $   Hardware
L18    12 PATH3B= MP21 * TP21 * GP_D + TP23 * TP24 * GP_E                $   Hardware
L18    13 PTH3BC= D4AV * GP_E                                            $   Hardware
L18    14 PATH4B= MP22 * TP22 * TP24 * GP_F + MP22 * TP22 * TP23 * GP_G  $   Hardware
L18    15 PTH4BC= D4AV * MP22 * GP_F + D4AV * MP22 * GP_G                $   Hardware
L18    16 PATH5B= MP21 * TP21 * TP24 * GP_H + MP21 * TP21 * TP23 * GP_I  $   Hardware
L18    17 PTH5BC= D4AV * MP21 * GP_H + D4AV * MP21 * GP_I                $   Hardware
L18    18 PATH6B= MP21 * TP21 * MP22 * TP22 * GP_J                       $   Hardware
L18    19 PTH6BC= D4AV * MP21 * MP22 * GP_J                              $   Hardware
L18    20 PATH7B= MP22 * TP22 * TP23 * TP24 + MP21 * TP21 * TP23 * TP24  $   Hardware
L18    21 PTH7BC= G4AV * (MP21 + MP22)                                   $   Hardware
L18    22 PATH8B= MP21 * TP21 * MP22 * TP22 * (TP23 + TP24)              $   Hardware
L18    23 L18_M = PP21MB + PP22MB                                        $ Maintenance
L18    24 PP22MB= TPMP_M * (PMP21 + OTHR1B)                              $ Maintenance of turbine driven pump 22
L18    25 PP21MB= MPMP_M * (PMP22B + OTHR2B + OTH2BC)                    $   Maintenance of motor driven pump 21
L18    26 L18_T = PP21TB + PP22TB                                        $ Test unavailability
L18    27 PP22TB= PMP_T * (PMP21 + OTHR1B)                               $ Test of turbine driven pump 22
L18    28 PP21TB= PMP_T * (PMP22B + OTHR2B + OTH2BC)                     $   Test of motor driven pump 21
L18    29 OTHR1B= SG21 + SG22 + MP21 + MP22                              $ Hardware
L18    30 OTHR2B= OTHR3B+ OTHR4B+ OTHR5B+ OTHR6B+ OTHR7B                 $ Hardware
L18    31 OTH2BC= D4AV*(GP_E + GP_F + GP_G + GP_H + GP_I + GP_J) + G4AV  $ Hardware
L18    32 OTHR3B= TP24 * GP_A + TP23 * GP_B + TP22 * GP_C + TP21 * GP_D  $ Hardware
L18    33 OTHR4B= TP23*TP24 * GP_E + TP22*TP24 * GP_F                    $ Hardware
L18    34 OTHR5B= TP22*TP23 * GP_G + TP21*TP24 * GP_H                    $ Hardware
L18    35 OTHR6B= TP21*TP23 * GP_I + TP21*TP22 * GP_J                    $ Hardware
L18    36 OTHR7B= TP21*TP22*(TP23+TP24) + (TP21+TP22)*TP23*TP24          $ Hardware
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
L19     1 L19    = L19_H + L19_M + L19_T + L19_C + OPERRR          $ AFS TOTAL (ATWS - < 40%) LOSS of all AC power
L19     2 L19_H = SUPPLY +(1 - CSTANK)* PUMPSC + PATHSC + CSTANK*PUMCSC   $  HARDWARE
L19     3 PUMPSC= PMP22B                                            $   Pump trains
L19     4 PUMCSC= PMC22                                             $   Pump trains
L19     5 PATHSC= PATH1C + PATH2C + PATH3C+PATH4C+PATH5C+PATH6C+PATH7C  $     Paths
L19     6 L19_C = PTH3CC + PTH4CC + PTH5CC + PTH6CC                 $  Common Cause
L19     7 PATH1C= SG21 * SG22 * (SG23+SG24) + (SG21+SG22) * SG23 * SG24  $ Flow path
L19     8 PATH2C= TP24 * GP_A + TP23 * GP_B + TP22 * GP_C + TP21 * GP_D  $ Flow path
L19     9 PATH3C= TP23*TP24 * GP_E + TP22*TP24 * GP_F               $ Flow path
L19    10 PTH3CC= D4AV * (GP_E + GP_F)                              $ Flow path
L19    11 PATH4C= TP22 * TP23 * GP_G + TP21 * TP24 * GP_H           $ Flow path
L19    12 PTH4CC= D4AV * (GP_G + GP_H)                              $ Flow path
L19    13 PATH5C= TP21 * TP23 * GP_I + TP21 * TP22 * GP_J           $ Flow path
L19    14 PTH5CC= D4AV * (GP_I + GP_J)                              $ Flow path
L19    15 PATH6C= (TP21 + TP22) * TP23 * TP24                       $ Flow path
L19    16 PTH6CC= G4AV                                              $ Flow path
L19    17 PATH7C= TP21 * TP22 * (TP23 + TP24)                       $ Flow path
L19    18 L19_M = TPMP_M                                            $  Maintenance
L19    19 L19_T = PMP_T                                             $  Test unavailability
L1A     1 L41TOP= L41_H + L41_M + L41_T + OPERRR                    $ Total AFS - ATWS ( >40%) all power
L1A     2 L41_H = CSTANK + PUMPSD + PATH5D                          $ Random Hardware Failures
L1A     3 PATH5D= PMP21 + PMP23                                     $   Pump path
L1A     4 PUMPSD= MP21 + MP22 + MP23 + MP24 + 4 * BFD79             $   Pump stand-by failures
L1A     5 L41_M = 2 * MPMP_M                                        $  Pump Maintenance
L1A     6 L41_T = 2 * PMP_T                                         $  Testing unavailability
L1F     1 L2F    = 1.00                                             $ Guaranteed failure of the AFW function
          SUPPLY= CSTANK * CWTANK                                   $   Water supply
          OPERRR= OPERR * OPREC * COUPL                             $  Operator error - testing
          GP_A  = SG21 * SG22 + SG21 * SG23 + SG22 * SG23           $
          GP_B  = SG21 * SG22 + SG21 * SG24 + SG22 * SG24           $
          GP_C  = SG21 * SG23 + SG21 * SG24 + SG23 * SG24           $
          GP_D  = SG22 * SG23 + SG22 * SG24 + SG23 * SG24           $
          GP_E  = SG21 + SG22                                       $
          GP_F  = SG21 + SG23                                       $
          GP_G  = SG21 + SG24                                       $
          GP_H  = SG22 + SG23                                       $
          GP_I  = SG22 + SG24                                       $
          GP_J  = SG23 + SG24                                       $
          SG21  = BFD79                                             $
          SG22  = BFD791                                            $
          SG23  = BFD793                                            $
          SG24  = BFD792                                            $
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
MP21   = BFD62  + FV406A + BFD37 + BFD38                              $
MP22   = BFD621 + FV406B + BFD35 + BFD36                              $
MP23   = BFD622 + FV406C + BFD40 + BFD41                              $
MP24   = BFD623 + FV406D + BFD42 + BFD43                              $
TP21   = BFD48  + FV405A + BFD47  + BFD481                            $
TP22   = BFD482 + FV405B + BFD471 + BFD483                            $
TP23   = BFD484 + FV405C + BFD472 + BFD485                            $
TP24   = BFD486 + FV405D + BFD473 + BFD487                            $
PMP21 = CT26 + CT27 + MP21S + BFD34 + MP21R                           $
PMP23 = CT32 + CT33 + MP23S + BFD39 + MP23R                           $
PMP22 = CT29 + CT30 + TP22S + BFD31 + TP22R + STMSUP                  $
PMP22A= CT29 + CT30 + TP22SA + BFD31 + TP22R + STMSUP                 $
PMP22B= CT29 + CT30 + TP22SB + BFD31 + TP22R + STMSUP                 $
PMC21 = CT25 + PV1187 + MP21S + BFD34 + MP21R                         $
PMC23 = CT31 + PV1189 + MP23S + BFD39 + MP23R                         $
PMC22 = CT28 + PV1188 + TP22S + BFD31 + TP22R + STMSUP                $
STMSUP= PV1139 + MS54 + PV310B + PV310A + MS41 * MS42                 $
BFD79 = IPV02D                                                        $
BFD791= IPV02D                                                        $
BFD792= IPV02D                                                        $
BFD793= IPV02D                                                        $
BFD62 = IPV01T * (T1 + T4)                                            $
BFD621= IPV01T * (T1 + T4)                                            $
BFD622= IPV01T * (T1 + T4)                                            $
BFD623= IPV01T * (T1 + T4)                                            $
FV406A= IPV05T * (T1 + T4)                                            $
FV406B= IPV05T * (T1 + T4)                                            $
FV406C= IPV05T * (T1 + T4)                                            $
FV406D= IPV05T * (T1 + T4)                                            $
BFD37 = IPV02D                                                        $
BFD35 = IPV02D                                                        $
BFD40 = IPV02D                                                        $
BFD42 = IPV02D                                                        $
BFD38 = IPV01T * (T1 + T4)                                            $
BFD36 = IPV01T * (T1 + T4)                                            $
BFD41 = IPV01T * (T1 + T4)                                            $
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
BFD43 = IPV01T * (T1 + T4)                          $
BFD48 = IPV01T * (T1 + T4)                          $
BFD482= IPV01T * (T1 + T4)                          $
BFD484= IPV01T * (T1 + T4)                          $
BFD486= IPV01T * (T1 + T4)                          $
BFD481= IPV01T * (T1 + T4)                          $
BFD483= IPV01T * (T1 + T4)                          $
BFD485= IPV01T * (T1 + T4)                          $
BFD487= IPV01T * (T1 + T4)                          $
FV405A= IPV05D + IPV05T * T1                        $
FV405B= IPV05D + IPV05T * T1                        $
FV405C= IPV05D + IPV05T * T1                        $
FV405D= IPV05D + IPV05T * T1                        $
D4AV  = 1/3 * IPVB5D * (1 - IPVG5D) * IPV05D        $ Common cause - 2 of 4  FCVs(405A,B,C,D)
G4AV  = IPVB5D * IPVG5D * IPV05D                    $ Common cause - Global failure of 4 FCVs(405A,B,C,D)
BFD47 = IPV02D                                      $
BFD471= IPV02D                                      $
BFD472= IPV02D                                      $
BFD473= IPV02D                                      $
CT25  = IPV02D                                      $
CT26  = IPV02D                                      $
CT27  = IPV01T * (T1 + T2)                          $
PV1187= IPV05D + IPV05T * T1                        $
BFD34 = IPV02D                                      $
CT31  = IPV02D                                      $
CT32  = IPV02D                                      $
CT33  = IPV01T * (T1 + T2)                          $
PV1189= IPV05D + IPV05T * T1                        $
BFD39 = IPV02D                                      $
CT28  = IPV02D                                      $
CT29  = IPV02D                                      $
CT30  = IPV01T * (T1 + T2)                          $
PV1188= IPV05D + IPV05T * T1                        $
BFD31 = IPV02D                                      $
D3AV  = 1/2 * IPVB5D * (1 - IPVG5D) * IPV05D        $ Common cause, 2 of 3 PCVs (1187,1188,1189)
G3AV  = IPVB5D * IPVG5D * IPV05D                    $ Common cause - Global failure of 3 PCVs (1187,1188,1189)
CCPUMP= CCPMPS + CCPMPR                             $ Common cause failure of motor driven  pumps
CCPMPS= IPB10S * IPP10S                             $ Common cause failure of MDPs to start
CCPMPR= IPB10R * IPP10R * T1                        $ Common cause failure of MDPs during operation
MP21S = IPP10S                                      $
MP21R = IPP10R * T1                                 $
MP23S = IPP10S                                      $
MP23R = IPP10R * T1                                 $
```

TABLE 3.2-3(c)
AFS EQUATION FILE

```
TP22S = 0.5 * (IPP02S + IPP02S* IPOP02) + (1-IPP02S) * IPOP01    $ AFWP 22 - Normal Response
TP22SA= IPP02S + (1-IPP02S) * IPOP03                             $ AFWP 22 - Core Cooling Rec
TP22SB= IPP02S + (1-IPP02S) * IPOP04                             $ AFWP 22 - ATWS (<40%)
TP22R = IPP02R * T1                                              $
PV1139= IPV05D + IPV05T * T1                                     $
MS54  = IPV01T * (T1 + T2)                                       $
PV310B= IPV05T * (T1 + T2)                                       $
PV310A= IPV05T * (T1 + T2)                                       $
MS41  = IPV02D                                                   $
MS42  = IPV02D                                                   $
CSTANK= CT6 + CT64 + TANK                                        $  Condensate storage tank
CT6   = IPV01T * T1                                              $
CT64  = IPV01T * (T1 + T2)                                       $
CWTANK= IPOP05 + (1-IPOP05)*(CT49 + FV1205 + TANK)               $  City water storage tank
CT49  = IPV01T * (T1 + T3)                                       $
TANK  = IPTNKL * T1                                              $
FV1205= IPV05D                                                   $
TPMP_M= IPPF02 * IPPD02                                          $  Maintenance unavailability - TD pump
MPMP_M= IPPF10 * IPPD10                                          $  Maintenance unavailability - MD pump
PMP_T = 0.5 / 2190                                               $  Test unavailability - either pump
OPERR = HEC1                                                     $  Operator error - misalign valves
OPREC = HE02A                                                    $
COUPL = (1+19*HEC1)/20                                           $
T1    = 24.0                                                     $  Mission time
T2    = 2190 / 2                                                 $  One half of the quarterly test interval
T3    = 175000.0                                                 $  Effective test interval for CTV - 49 (city water supply)
T4    = 13140 / 2                                                $  One half of refueling test
```

TABLE 3.2-4a

CCW SPLIT FRACTIONS

Split Fraction	Definition
CC1	CCW - Initial Response - Power Available to All Buses
CC2	CCW - Initial Response - Power lost to one bus (5A, 2A-or-3A)
CC3	CCW - Initial Response - Power available on 1 bus (5A, 2A, 6A)
CCF	CCW - Initial Response - Guaranteed failure of the CCWS
COA	CCW - Following Offsite Power Recovery - Power Initially Lost to All Pumps (No Pumps Initially Challenged)
CO1	CCW - Following Offsite Power Recovery - Power Initially Lost to One Pump (Two Pumps Initially Challenged and Failed)
CO2	CCW - Following Offsite Power Recovery - Power Initially Lost to Two Pumps (One Pump Initially Challenged and Failed)
COF	CCW - Following Offsite Power Recovery - Power Initially Avail to All Pumps (Three Pumps Initially Challenged and Failed - Guaranteed Failure)

TABLE 3.2-4b

CCW CAUSE TABLE

CC1	**CCW - Initial Response - Power Available to All Buses**
1.034E-04	CCW - All Power Available
1.057E-05	Hardware contribution
5.559E-06	Series components
3.602E-09	Two train failures (heat exchangers)
5.012E-06	Block D (heat exchanger 21 train)
6.278E-06	Maintenance unavailability
2.069E-06	Pump train failures
2.069E-06	Pump train failures
2.069E-06	Pump train failures
3.292E-07	Testing Contributions
7.126E-08	Heat Exchanger Maintenance
8.624E-05	Common Cause Failures
CC2	**CCW - Initial Response - Power lost to one bus (5A, 2A-or-3A)**
6.936E-04	CCW - Power lost to one bus (5A, 2A-or-3A)
2.502E-04	Hardware contribution
5.559E-06	Series components (Block F)
3.602E-09	Two train failures (heat exchangers)
2.446E-04	Pump train failures
1.258E-04	Maintenance unavailability
6.287E-05	Maintenance pump 21
6.287E-05	Maintenance pump 22
6.636E-06	Test unavailability
7.126E-08	Heat Exchanger maintenance
3.110E-04	Common Cause Failures
CC3	**CCW - Initial Response - Power available on 1 bus (5A, 2A, 6A)**
1.881E-02	CC3 - Power available on 1 bus (5A, 2A, 6A)
1.454E-02	Hardware contribution
5.559E-06	Series components
3.602E-09	Two train failures (heat exchangers)
1.453E-02	Pump train failures
4.047E-03	Maintenance unavailability
2.283E-04	Testing Unavailability
7.126E-08	Heat Exchanger Maintenance

TABLE 3.2-4b

CCW CAUSE TABLE (continued)

CCF	CCW - Initial Response - Guaranteed failure of the CCWS
1.000E 00	Guaranteed failure of the CCS.
COA	CCW - Following Offsite Power Recovery - Power Initially Lost to All Pumps
1.034E-04	CCW - Following OPR - Power Initially Lost to All Pumps
CO1	CCW - Following Offsite Power Recovery - Power Initially Lost to One Pump
1.421E-01	CCW - Following OPR - Power Initially Lost to One Pump
CO2	CCW - Following Offsite Power Recovery - Power Initially Lost to Two Pumps
5.559E-03	CCW - Following OPR - Power Initially Lost to Two Pumps
COF	CCW - Following Offsite Power Recovery - Power Initially Avail to All Pumps
1.000E 00	CCW - Following OPR - Power Initially Available to All Pumps

TABLE 3.2-4(c)
CCW EQUATION FILE

CC1	1	CC1TOP= CC1_H + CC1_M + CC1_C + CC1_T	$ CC1 - total Power to all pumps
CC1	2	CC1_H = BLOCKF + HX_F + PUMPS	$ Hardware contribution
CC1	3	BLOCKF= CCSTK + V734A + V734B + SWV32 + PIPE_F	$ Series components
CC1	4	HX_F = HX21 * HX22	$ Two train failures (heat exchangers)
CC1	5	PUMPS = PMP21S * PMP22S * PMP23S	$ Pump train failures
CC1	6	CC1_M = PMP21M + PMP22M + PMP23M + HXMN	$ Maintenance unavailability
CC1	7	PMP21M= P21M * (PMP22S * PMP23S + CC2PPS)	$ Maintenance pump 21
CC1	8	PMP22M= P22M * (PMP21S * PMP23S + CC2PPS)	$ Maintenance pump 22
CC1	9	PMP23M= P23M * (PMP21S * PMP22S + CC2PPS)	$ Maintenance pump 23
CC1	10	CC1_T = PMP21T + PMP22T + PMP23T	$ Test unavailability
CC1		PMP21T= TF * TD * (PMP22S * PMP23S + CC2PPS)	$ Test pump 21
CC1		PMP22T= TF * TD * (PMP21S * PMP23S + CC2PPS)	$ Test pump 22
CC1		PMP23T= TF * TD * (PMP21S * PMP22S + CC2PPS)	$ Test pump 23
CC1	11	HXMN = HX21M * HX22 + HX22M * HX21	$ Maintenance - heat exchanger
CC1	12	CC1_C = CC2PPS*(PMP21S + PMP22S + PMP23S) + CC3PPS	$ Common cause pump failures
CC2	1	CC2TOP= CC2_H + CC2_M + CC2_C + CC2_T	$ CC2 - Total, Power lost to one pump
CC2	2	CC2_H = BLOCKF + HX_F + PUMPS	$ Hardware contribution
CC2	3	BLOCKF= CCSTK + V734A + V734B + SWV32 + PIPE_F	$ Series components
CC2	4	HX_F = HX21 * HX22	$Two train failures (heat exchangers)
CC2	5	PUMPS = PMP21S * PMP22S	$ Pump train failures
CC2	6	CC2_M = PMP21M + PMP22M + HXMN	$ Maintenance unavailability
CC2	7	PMP21M= P21M * PMP22S	$ Maintenance pump 21
CC2	8	PMP22M= P22M * PMP21S	$ Maintenance pump 22
CC2	9	CC2_T = PMP21T + PMP22T	$ Test unavailability
CC2		PMP21T= TF * TD * PMP22S	$ Test pump 21
CC2		PMP22T= TF * TD * PMP21S	$ Test pump 22
CC2	10	HXMN = HX21M * HX22 + HX22M * HX21	$ Maintenance - heat exchanger
CC2	11	CC2_C = CC2PPS + CC3PPS	$ Common cause pump failures
CC3	1	CC3TOP= CC3_H + CC3_M + CC3_T	$CC3 - Total Power lost to 2pumps
CC3	2	CC3_H = BLOCKF + HX_F + PUMPS	$ Hardware contribution
CC3	3	BLOCKF= CCSTK + V734A + V734B + SWV32 + PIPE_F	$ Series components
CC3	4	HX_F = HX21 * HX22	$Two train failures (heat exchangers)
CC3	5	PUMPS = PMP23S	$ Pump train failures
CC3	6	CC3_M = P23M + HXMN	$ Maintenance unavailability
CC3	7	CC3_T = TF * TD	$ Test unavailability
CC3	8	HXMN = HX21M * HX22 + HX22M * HX21	$ Maintenance - heat exchanger
CCF	1	CCFTOP= 1.00	$ Guaranteed failure of CCW
COA	1	COA = COATOP	$ Following Offsite Power Recovery - Power Initially lost to All Pumps (No Pumps initially Challenged)
CO1	1	CO1 = COATOP/CO1TOP	$ Following Offsite Power Recovery - Power Initially Lost to One Pump (Two Pumps Initially Challenged and Failed)
CO2	1	CO2 = COATOP/CO2TOP	$ Following Offsite Power Recovery - Power Initially Lost to Two Pumps (One Pump Initially Challenged and Failed)
COF	1	COF = COATOP/COATOP	$ Following Offsite Power Recovery - Power Initially Available to All Pumps (Three Pumps Initially Challenged and Failed - Guarenteed Failure)

TABLE 3.2-4(c)
CCW EQUATION FILE

```
COATOP= CC1_H + CC1_M + CC1_C + CC1_T                         $ COA - Total Power on all 3 buses
CC1_H = BLOCKF + HX_F + PUMPS                                 $  Hardware contribution
PUMPS = PMP21S * PMP22S * PMP23S                              $   Pump train failures
CC1_M = PMP21M + PMP22M + PMP23M + HXMN                       $  Maintenance unavailability
PMP21M= P21M * (PMP22S * PMP23S + CC2PPS)                     $   Maintenance pump 21
PMP22M= P22M * (PMP21S * PMP23S + CC2PPS)                     $   Maintenance pump 22
PMP23M= P23M * (PMP21S * PMP22S + CC2PPS)                     $   Maintenance pump 23
CC1_T = PMP21T + PMP22T + PMP23T                              $   Test unavailability
PMP21T= TF * TD * (PMP22S * PMP23S + CC2PPS)                  $   Test pump 21
PMP22T= TF * TD * (PMP21S * PMP23S + CC2PPS)                  $   Test pump 22
PMP23T= TF * TD * (PMP21S * PMP22S + CC2PPS)                  $   Test pump 23
HXMN  = HX21M * HX22 + HX22M * HX21                           $   Maintenance - heat exchanger
CC1_C = CC2PPS*(PMP21S + PMP22S + PMP23S) + CC3PPS            $  Common cause pump failures
CO1TOP= CC2_H + CC2_M + CC2_C + CC2_T                         $ CO1 - Power failed on  1 Bus
CC2_H = BLOCKF + HX_F + PUMPS                                 $  Hardware contribution
PUMPS = PMP21S * PMP22S                                       $   Pump train failures
CC2_M = PMP21M + PMP22M + HXMN                                $  Maintenance unavailability
PMP21M= P21M * PMP22S                                         $   Maintenance pump 21
PMP22M= P22M * PMP21S                                         $   Maintenance pump 22
CC2_T = PMP21T + PMP22T                                       $  Test unavailability
```

TABLE 3.2-4(c)
CCW EQUATION FILE

```
PMP21T= TF * TD * PMP22S                                         $   Test pump 21
PMP22T= TF * TD * PMP21S                                         $   Test pump 22
HXMN   = HX21M * HX22 + HX22M * HX21                             $   Maintenance - heat exchanger
CC2_C = CC2PPS + CC3PPS                                          $  Common cause pump failures
CO2TOP= CC3_H + CC3_M + CC3_T                                    $ CO2 - Power failed on 2 buses
CC3_H = BLOCKF + HX_F + PUMPS                                    $  Hardware contribution
BLOCKF= CCSTK + V734A + V734B + SWV32 +  PIPE_F                  $   Series components
HX_F   = HX21 * HX22                                             $ Two train failures (heat exchangers)
PMPS = PMP23S                                                    $   Pump train failures
CC3_M = P23M + HXMN                                              $  Maintenance unavailability
CC3_T = TF * TD                                                  $  Test unavailability
HXMN   = HX21M * HX22 + HX22M * HX21                             $   Maintenance - heat exchanger
CC2PPS= 1/2 * IPB05S * (1 - IPG05S) * IPP05S + CC2PPR            $Common cause - 2 of 3 CCW  pumps fail to start
CC2PPR= 1/2 * IPB05R * (1 - IPG05R) * IPP05R * T24               $Common cause - 2 of 3 CCW  pumps fail during operation
CC3PPS= IPB05S * IPG05S * IPP05S + CC3PPR                        $Common cause - 3 of 3 CCW  pumps fail to start
CC3PPR= IPB05R * IPG05R * IPP05R * T24                           $Common cause - 3 of 3 CCW  pumps fail during operation
PMP21S= (1-P21M) * STBYS + PMP21R + P21M24                       $
PMP22S= (1-P22M) * STBYS + PMP22R + P22M24                       $
PMP23S= (1-P23M) * STBYS + PMP23R + P23M24                       $
PMP21R= (1 - P21M) * (IPP05R + 2 * IPV01T) * T24                 $  Pump 21 - run 24 hours
PMP22R= (1 - P22M) * (IPP05R + 2 * IPV01T) * T24                 $  Pump 22 - run 24 hours
PMP23R= (1 - P23M) * (IPP05R + 2 * IPV01T) * T24                 $  Pump 23 - run 24 hours
STBYS = IPP05S + IPV02D + 2 * IPV01T * T2 + OPERR                $  Standby pump start
P21M   = IPPF05 * IPPD05                                         $  Maintenance unavailability pump 21
P22M   = IPPF05 * IPPD05                                         $  Maintenance unavailability pump 22
P23M   = IPPF05 * IPPD05                                         $  Maintenance unavailability pump 23
P21M24= IPPF05 * MPD24                                           $
P22M24= IPPF05 * MPD24                                           $
P23M24= IPPF05 * MPD24                                           $
HX21   = (2 * IPV01T + 2 * IPV01T + IPH01L) * T24                $  Block D (heat exchanger 21 train)
HX22   = (2 * IPV01T + 2 * IPV01T + IPH01L + 2 * IPV01T) * T24   $  Block (heat exchanger 22   train)
HX21M = IPHF02 * IPHD02                                          $  Maintenance - heat exchanger  21
HX22M = IPHF02 * IPHD02                                          $  Maintenance - heat exchanger  22
CCSTK = (IPTNK2 + IPV01T) * T24                                  $  Component cooling surge tank
V734A = IPV01T * T24                                             $  CCW valve 734A
V734B = IPV01T * T24                                             $  CCW valve 734B
SWV32 = IPV01T * T24                                             $  SWS valve SWN-32
PIPE_F= 18 * IPPP2R * T24                                        $  18 pip sections
OPERR = TF * OP1 * 2190                                          $  Unavailability of STBY pump due to operator error
MPD24 = 12                                                       $
OP1    = HE01A                                                   $  Op. fails to reopen manual valve at standby pump after test
TF     = 1 / 2190                                                $  Test frequency
TD     = 0.5                                                     $  Test duration
T24    = 24.0                                                    $  Mission time
T2     = 2190  / 2                                               $  Quarterly test interval
```

TABLE 3.2-5a

CSS SPLIT FRACTIONS

Split Fraction	Definition
CS1	Containment Spray Injection - all support available
CS2	Containment Spray Injection - loss of one bus (5A or 6A).
CS3	Containment Spray Injection - loss of one bus and one ESFAS signal.
CS4	Containment Spray Recirculation - all power available
CS5	Containment Spray Recirculation - loss of one bus (5A or 6A)
CSF	Guaranteed failure of the CSS.
CA1	Containment Spray Actuation - both channels available (Total)
CA2	Containment Spray Actuation - single channel available (Total)

TABLE 3.2-5b

CSS CAUSE TABLE

CS1	Containment spray system - all support available
4.953E-04	Containment spray system - all support available
1.641E-04	Hardware failure
1.992E-05	Maintenance Unavailability
6.554E-08	Testing Unavailability
1.937E-05	Human error
2.918E-04	Common Cause
CS2	Containment Spray Injection - loss of one bus (5A or 6A).
2.162E-02	CSS - loss of one bus (5A or 6A).
2.052E-02	Hardware failure
8.810E-04	Maintenance unavailability
2.975E-06	Test unavailability
1.997E-04	Human error
1.548E-05	Common Cause
CS3	Containment Spray Injection - loss of one bus and one ESFAS signal.
5.108E-01	Containment Spray Injection - loss of one bus and one ESFAS signal.
CS4	Containment Spray Recirculation - all power available
1.383E-04	Containment Spray Recirculation - all power available
CS5	Containment Spray Recirculation - loss of one bus (5A or 6A)
1.717E-03	Containment Spray Recirculation - loss of one bus (5A or 6A)
CSF	Guaranteed failure of the CSS.
1.000E+00	Guaranteed failure of the CSS

TABLE 3.2-5b

CSS CAUSE TABLE
(continued)

CA1 Containment Spray Actuation - both channels available (Total)

2.022E-05	Containment Spray Actuation - both channels available (Total)
1.163E-05	Total Test Unavailability for two channels
5.813E-06	Test Unavailability per channel
5.675E-06	Hardware contribution - two channels
3.153E-07	Miscalibration
2.596E-06	Common cause

CA2 Containment Spray Actuation - single channel available (Total)

7.735E-03	Containment Spray Actuation - single channel available (Total)
7.735E-03	Hardware Contribution - Single channel
6.901E-03	Test - Single channel

TABLE 3.2-5(c)
CSS EQUATION FILE

CS1	1	CS1TOP= CS1_H + CS1_M + CS1_T + CS1_O + CS1_C	$ CSS - Total All Power Available
CS1	2	CS1_H = PMP21 * PMP22 + CA1	$ Hardware Failure
CS1	3	CS1_M = 2 * PMP21 * MNTUN	$ Maintenance
CS1	4	CS1_T = 2 * PMP21 * HEC1 * TESTU	$ Testing
CS1	5	CS1_O = COUPL * PND + 2 * OPERR * PND * PMP21	$ Human Error
CS1	6	PBOTH = COUPL	$ Human Error (P-Both)
CS1	7	TRAIN = PMP21	$ Single Train Failure
CS1	8	PLLMOV= PMOVS	$ Parallel MOV's
CS1	9	CS1_C = CCPM + CCVLV	$ Common cause - CSS TOTAL
CS1	10	CCPM = IPB09S*IPP09S + IPB09R*IPP09R*T4	$ Common cause - pumps
CS1	11	CCVLV = 2*(1/3*IPVB4D*IPV04D*(1-IPVG4D)*PMP21)+CCVL1	$ Commom cause valves
CS1		CCVL1 = 3*(1/3*IPVB4D*IPV04D*(1-IPVG4D))**2+CCVL2	$
CS1		CCVL2 = 4*(1/3*IPVB4D*IPV04D*(1-IPVG4D)*PMOV**2)+CCVL3	$
CS1		CCVL3 = IPVB4D*IPVG4D*IPV04D	$
CS2	1	CS2TOP= CS2_H + CS2_M + CS2_T + CS2_O + CS2_C	$ CSS Total - One Bus Down
CS2	2	CS2_H = MOV + PUMP + PMOV + CHECK + MANVAL + CA2	$ Hardware Failure - One Pump Train
CS2	3	CS2_M = MNTUN	$ Maintenance
CS2	4	CS2_T = HEC1 * TESTU	$ Test
CS2	5	CS2_O = COUPL * PND + OPERR * PND	$ Human Error
CS2	6	CS2_C = IPVB4D*PMOV	$ CS2 Total common cause
CS3	1	CS3 = 0.5 * (CS2 + CSF)	$ CSS Total- loss of one bus and one ESFAS signal
CS3		CSF = 1.00	$
CS3		CS2 = CS2_H + CS2_M + CS2_T + CS2_O	$ Total CSS Unavailability - One Bus Down
CS3		CS2_H = MOV + PUMP + PMOV + CHECK + MANVAL + CA2	$ Hardware Contribution
CS3		CS2_M = MNTUN	$ Maintenance Contribution
CS3		CS2_T = HEC1 * TESTU	$ Test Contribution
CS3		CS2_O = COUPL * PND + OPERR * PND	$ Operator Error Contribution
CS4	1	CR1 = HE1 + HW1 + CC1	$ Cont. Spray Recirc - all power available
CS4	2	HE1 = IPOPR9	$ Operator fails to align spray recirculation
CS4	3	HW1 = MV889A * MV889B	$ Hardware
CS4	4	CC1 = IPVB4D * IPV04D	$ Common Cause
CS5	1	CR2 = HE2 + HW2 + CC2	$ Cont. Spray Recirc. Bus 5A or 6A failed
CS5	2	HE2 = IPOPR9	$ Operator error
CS5	3	HW2 = MV889A	$ Hardware
CS5	4	CC2 = 0	$ Common Cause
CSF	1	CSFTOP= 1.00	$ Guaranteed failure of the CSS.
CA1	1	CA1 = CHAN2C + INSTC + TEST1 + MISCAL + CCCA	$ CA System Total
CA1	2	TEST1 = TEST1	$ Test on 2 SI Channels
CA1	3	TST11 = TST11	$ Test x Single SI Channel
CA1	4	CHAN2 = CHAN2C	$ Hardware Contribution - Two Channels
CA1	5	CHAN1 = CHAN1C	$ Single CA Logic Channel
CA1	6	INST = INSTC	$ CA Instrumentation
CA1	7	MISCAL= MISCAL	$ Miscalibration
CA1	8	CA1_C = CCCA	$ Common cause
CA2	1	CA2 = CHAN1C+ INSTC+ TEST2 + MISCAL	$ CS actuation - single channel
CA2	2	TEST2 = TEST2	$ Test - single channel
		CA1 = CHAN2C + INSTC + TEST1 + MISCAL	$
		CA2 = CHAN1C+ INSTC + TEST2 + MISCAL	$

TABLE 3.2-5(c)
CSS EQUATION FILE

```
TEST1 = 2 * TST11                                              $
TST11 = TSTREL * CHAN1C                                        $
TEST2 = TSTREL                                                 $
CHAN2C= CHAN1C * CHAN1C                                        $
CHAN1C= 2*(RELS+FUSE)+MASREL+2*AUXREL+LOGIC1+ RSPBS            $
CCCA  = CCMR + CCARCA + CCBICA + CCTRCA                        $  Total common cause - SPRAY  actuation
CCMR  = IPRB1D * MASREL                                        $  Common cause - master relay
CCARCA= 4/3*IPRB1D*(1-IPGR1D)*AUXREL+IPRB1D*IPGR1D*AUXREL      $  Common cause - auxiliary  relays
CCBICA= 2*(3/2*IPBSWD*(1-IPGSWD)*IPSW2D+IPBSWD*IPGSWD*IPSW2D)$  Common cause - bistables
CCTRCA= (6*CC2REL+CCGREL)*(6*CC2REL+CCGREL)                    $  Common cause logic relays
INSTC = 6 * CPXMTR * CPXMTR                                    $
MISCAL= (CPXMTR + BISREL) * (CPXMTR + BISREL)                  $  Miscalibr. of both sets of instr. channels (IPPSS 1.5-424)
MASREL= IPRO1D                                                 $  Master relay
AUXREL= IPRO1D                                                 $  Auxiliary relay
LOGIC1= 6*(IPTR1D*IPTR1D+CC2REL)                               $  Single train logic relays
CC2REL= 1/5*IPBTRD*(1-IPGTRD)*IPTR1D                           $  2 of 6 logic relays - common cause
CCGREL= IPBTRD*IPGTRD*IPTR1D                                   $  Global 6 logic relays(1 train)
FUSE  = IPFUSO * T1                                            $  Fuse
TSTREL= IPRT01/(2*T2)                                          $  Test unavailability
BISREL= IPTR1D + IPSW2D*T2                                     $  Bistable relay
CPXMTR= IPT02F * T1 + IPSW2D                                   $  Containment pressure transmitter
RELS  = IPSW3S * T2                                            $  Short around relay contacts
RSPBS = IPSW3S * T2                                            $  Short accross reset pushbutton
PMP21 = MOV + PUMP + PMOVS + CHECK + CSHISO                    $  Single Train Failure - train A
PMP22 = MOV + PUMP + PMOVS + CHECK + CSHISO                    $  Single Train Failure - train B
CSHISO= MOV                                                    $
MOV   = IPV01T * T3                                            $  MOV transfer closed
PUMP  = IPP09S + IPP09R * T4                                   $  CS pump start and run
PMOVS = PMOV * PMOV                                            $  Discharge MOV x discharge MOV
MANVAL= IPV01T                                                 $
PMOV  = IPV04D                                                 $  MOV failure on demand
CHECK = IPV02D                                                 $  Check valve
MNTUN = IPPF09 * IPPD09                                        $  Maintenance unavailability -  CS pump
COUPL = OPERR * ((1 + 19 * OPERR) / 20)                        $  Operator error - coupling
PND   = HE02A                                                  $
OPERR = HEC1                                                   $ Operator error of commission  - Type I
TESTU = IPPT01/(T3* 2)                                         $
MV889A= IPV04D                                                 $
MV889B= IPV04D                                                 $
IPOPR9= 1.2E-04                                                $Operator fais to switch to CS  recirculation
T1    = 4.0                                                    $  Time to detect fuse failure
T2    = 720/2                                                  $  Half monthly test interval for ESAF
T3    = 2190/2                                                 $  One half of test interval for CSS
T4    = 2                                                      $  Mission time
```

TABLE 3.2.6a

EPS SPLIT FRACTIONS

Split Fraction	Definition
OG1	Loss of Offsite power - not as initiating event.
OGF	Loss of offsite power - initiating event.
Y51	Failure of 6.9kV bus 5 - offsite power available.
Y5F	Guaranteed failure of 6.9kV bus 5.
Z61	Failure of 6.9kV bus 6 - offsite power available.
Z6F	Guaranteed failure of 6.9kV bus 6.
W21	Failure of 6.9kV bus 2 - offsite power available.
W2F	Guaranteed failure of 6.9kV bus 2.
X31	Failure of 6.9kV bus 3 - offsite power available.
X32	Failure of 6.9KV bus 2/3-offsite power available.
X3F	Guaranteed failure of 6.9kV bus 3.
D11	Failure of DC bus 21 - power available to charger
D12	Failure of DC bus 21 - power lost to charger.
D1F	Guaranteed failure of DC bus 21.
D21	Failure of DC bus 22 - power available to charger
D22	Failure of DC bus 22 - power lost to charger(D1=S)
D23	Failure of DC bus 22 - power lost to charger(D1=F)
D2F	Guaranteed failure of DC bus 22.
D31	Failure of DC bus 23 - power available to charger
D32	Failure of DC bus 23 - power lost to charger (D1*D2=S)
D33	Failure of DC bus 23 - power lost to charger(D1+D2=F)
D34	Fail of DC bus 23, power lost to charger(D1*D2=F)
D3F	Guaranteed failure of DC bus 23.
D41	Failure of DC bus 24 - power available to charger
D42	Failure of DC bus 24 - power lost to charger
D43	Fail of DC Bus 24 - power lost to charger (D1+D2+D3=F)
D44	Fail DC Bus 24 - power lost to chrgr (D1*D2+D1*D3+D2*D3=F)
D45	Failure of DC Bus 24 - power lost to charger(D1*D2*D3=F)
D4F	Guaranteed failure of DC bus 24
DG2	Failure of two diesels - two available
DG3	Failure of three diesels - three available
G11	Failure of EDG 21 - single diesel challenged
G12	Failure of EDG 21 - two diesels challenged
G13	Failure of EDG 21 - three diesels challenged
G1F	Guaranteed failure of EDG 21
G1S	EDG 21 not required - normal power available

TABLE 3.2-6a

EPS SPLIT FRACTIONS
(continued)

Split Fraction	Definition
G21	Failure of EDG 22 - single diesel challenged
G22	Failure of EDG 22 (1st diesel) - two diesels challenged
G2A	EDG 22 fails given diesel 21 succeeds.
G2B	EDG 22 fails given diesel 21 fails.
G23	Failure of EDG 22 - three diesels challenged
G2C	EDG 22 fails given diesel 21 fails - 3 challenged
G2F	Guaranteed failure of EDG 22.
G2S	EDG 22 not required - normal power available
G31	Failure of EDG 23 - single diesel challenged
G32	EDG 23 fails given first diesel (21 or 22) succeeds.
G3A	EDG 23 fails given first diesel (21 or 22) fails.
G33	Failure of EDG 23 - three diesels challenged
G3B	EDG 23 fails after diesel 22 fails.
G3C	EDG 23 fails after diesel 21 fails.
G3D	EDG 23 fails after diesel 21 and 22 have failed.
G3F	Guaranteed failure of EDG 23.
G3S	EDG 23 not required - normal power available
A51	Failure of 480V bus 5A - bus 5 available
A52	Failure of 480V bus 5A - loss of power to bus 5.
A5F	Guaranteed failure of bus 5A.
A61	Failure of 480V bus 6A - bus 6 available.
A62	Failure of 480V bus 6A - loss of power to bus 6.
A6F	Guaranteed failure of bus 6A.
A21	Failure of 480V bus 2A - bus 2 available.
A22	Failure of 480V bus 2A - loss of power to bus 2.
A2F	Guaranteed failure of bus 2A.
A31	Failure of 480V bus 3A - bus 3 available.
A32	Failure of 480V bus 3A - loss of power to bus 3.
A3F	Guaranteed failure of bus 3A.
FO1	EDG fuel oil system - one pump available.
FO2	EDG fuel oil system - two pumps available.
FO3	EDG fuel oil system - three pumps available.
FOF	Guaranteed failure of the EDG fuel oil system.

TABLE 3.2-6b

EPS CAUSE TABLE

OG1	Loss of offsite grid - not as initiating event
3.343E-06	Loss of offsite grid - not as initiating event
3.343E-06	Station auxiliary transformer
OGF	Loss of offsite power - initiating event
1.000E 00	Loss of offsite power - initiating event
Y51	Offsite power available - Failure of 6.9kV bus 5
1.399E-05	Offsite power available - Failure of 6.9kV bus 5
1.399E-05	Hardware failure
Y5F	Guaranteed failure of 6.9kV bus 5
1.000E 00	Guaranteed failure of 6.9kV bus 5
Z61	Offsite Power Available - Failure of 6.9kV bus 6
1.399E-05	Offsite Power Available - Failure of 6.9kV bus 6
1.399E-05	Hardware failure
Z6F	Guaranteed failure of 6.9kV bus 6
1.000E 00	Guaranteed failure of 6.9kV bus 6

Table 3.2-6b
EPS CAUSE TABLE
(continued)

W21	Offsite Power Available - Failure of 6.9kV bus 2
1.355E-03	Offsite Power Available - Failure of 6.9kV bus 2
1.355E-03	Hardware
W2F	Guaranteed failure of 6.9kV bus 2
1.000E 00	Guaranteed failure of 6.9kV bus 2
X31	Failure of 6.9kV bus 3 - offsite power available
1.355E-03	Failure of 6.9kV bus 3 - offsite power available
1.355E-03	Hardware
X32	Failure of 6.9kV bus 3 given failure of bus 2 and no LOSP
7.312E-02	Failure of 6.9kV bus 3 given failure of bus 2 and no LOSP
7.312E-02	Common Cause
X3F	Guaranteed failure of 6.9kV bus 3
1.000E 00	Guaranteed failure of 6.9kV bus 3
D11	Failure of DC bus 21 - power avail. to the charger
2.730E-06	Failure of DC bus 21 - power avail. to the charger
2.730E-06	Hardware
D12	4.764E-04 Failure of DC bus 21 - power lost to the charger
4.764E-04	Failure of DC bus 21 - power lost to the charger
4.764E-04	Hardware
D1F	1.000E+00 Guaranteed failure of DC bus 21
1.000E 00	Guaranteed failure of DC bus 21
D21	2.730E-06 Failure of DC bus 22 - power avail. to the charger
2.730E-06	Failure of DC bus 22 - power avail. to the charger
2.730E-06	Hardware
D22	4.764E-04 Failure of DC bus 22 - power lost to the charger
4.764E-04	Failure of DC bus 22 - power lost to the charger
4.764E-04	Hardware

Table 3.2-6b

EPS CAUSE TABLE
(continued)

D23	Failure of DC Bus 23 given failure of D1
5.737E-02	Failure of DC Bus 23 given failure of D1
D2F	Guaranteed failure of DC bus 22
1.000E 00	Guaranteed failure of DC bus 22
D31	Failure of DC bus 23 - power avail. to the charger
6.527E-05	Failure of DC bus 23 - power avail. to the charger
D32	Failure of DC bus 23 - power lost to the charger
5.386E-04	Failure of DC bus 23 - power lost to the charger
D33	Failure of DC Bus 23, power lost to charger and D1 or D2 failed
5.737E-02	Failure of DC Bus 23, power lost to charger and D1 or D2 failed
D34	Failure of DC Bus 23, power lost to charger and D1 and D2 failed
8.109E-01	Failure of DC Bus 23, power lost to charger and D1 and D2 failed
D3F	Guaranteed failure of DC bus 23
1.000E 00	Guaranteed failure of DC bus 23
D41	Failure of DC bus 24 - power avail. to the charger
4.964E-05	Failure of DC bus 24 - power avail. to the charger
D42	Failure of DC bus 24 - power lost to the charger
5.231E-04	Failure of DC bus 24 - power lost to the charger

Table 3.2-6b

EPS CAUSE TABLE
(continued)

D43 Failure of DC Bus 24, power lost to charger and D1 or D2 or D3 failed

5.737E-02 Failure of DC Bus 24, power lost to charger and D1 or D2 or D3 failed

D44 Failure of DC Bus 24, power lost to charger and two DC buses failed

8.109E-01 Failure of DC Bus 24, power lost to charger and two DC buses failed

D45 Failure of DC Bus 24, power lost to charger and D1, D2 and D3 failed

1.000E 00 Failure of DC Bus 24, power lost to charger and D1, D2 and D3 failed

D4F Guaranteed failure of DC bus 24

1.000E 00 Guaranteed failure of DC bus 24

DG2 Failure of two diesels - two available

2.260E-03 Failure of two diesels - two available
3.945E-04 Hardware
1.708E-03 Maintenance
3.499E-05 Operator error
1.444E-05 Errors affecting 1 diesel
2.054E-05 Errors affecting 2 diesels
3.112E-05 Service water supply
9.103E-05 Common cause
1.816E-02 Single diesel start and run

DG3 Failure of three diesels - three available

1.656E-04 Failure of three diesels - three available
1.028E-05 Hardware
6.838E-05 Maintenance
3.394E-06 Operator error
7.824E-07 Errors affecting 1 diesel
1.331E-06 Errors affecting 2 diesels
1.281E-06 Errors affecting 3 diesles
3.457E-05 Service water outlet
4.892E-05 Common cause

Table 3.2-6b

EPS CAUSE TABLE
(continued)

G11	Failure of EDG 21 - single diesel challenged
6.436E-02	Failure of EDG 21 - single diesel
1.782E-02	Diesel generator hardware
2.948E-03	Diesel start
1.487E-02	Diesel run
4.607E-02	Diesel generator maintenance
0.000E 00	Diesel generator test
0.000E 00	Diesel generator common cause
4.334E-04	Operator errors
6.017E-06	Mispositioned control switch
4.274E-04	Undetecteded maintenance error
3.371E-05	Service water to diesel generator 21
2.389E-09	Service water outlet
G12	Failure of EDG 21 - two diesels challenged
6.413E-02	Failure of EDG 21 - two diesels challenged
G13	Failure of EDG 21 - three diesels challenged
6.404E-02	Failure of EDG 21 - three diesels challenged
G1F	Guaranteed failure of EDG 21
1.000E 00	Guaranteed failure of EDG 21
G1S	EDG 21 not required - Normal power available
0.000E 00	EDG 21 not required - Normal power available
G21	Failure of EDG 22 - single diesel challenged
6.432E-02	Failure of EDG 22 - single diesel challenged

Table 3.2-6b

EPS CAUSE TABLE
(continued)

G22	Failure of EDG 22 (first diesel) - two diesels challenged
6.458E-02	Failure of EDG 22 (first diesel) - two diesels challenged
G2A	Failure of EDG 22 given EDG 21 succeeds.
6.617E-02	Failure of EDG 22 given EDG 21 succeeds.
G2B	Failure of EDG 22 given EDG 21 fails
3.286E-02	Failure of EDG 22 given EDG 21 fails
G23	Failure of EDG 22 - three diesels challenged
6.633E-02	Failure of EDG 22 - three diesels challenged
G2C	Diesel 22 given 21 fails - three diesels challenged
3.313E-02	Diesel 22 given 21 fails - three diesels challenged
G2F	Guaranteed failure of EDG 22
1.000E 00	Guaranteed failure of EDG 22
G2S	EDG 22 not required - Normal power available
0.000E 00	EDG 22 not required - Normal power available
G31	Failure of EDG 23 - single diesel challenged
6.416E-02	Failure of EDG 23 - single diesel challenged
G32	Failure of EDG 23 given first diesel (EDG 21 or 22) succeeds.
6.596E-02	Failure of EDG 23 given first diesel (EDG 21 or 22) succeeds.

Table 3.2-6b

EPS CAUSE TABLE
(continued)

G33	Failure of EDG 23 - three diesels challenged
1.214E-01	Failure of EDG 23 - three diesels challenged
G3B	Failure of EDG 23 given diesel 22 fails
3.180E-02	Failure of EDG 23 given diesel 22 fails
G3C	Failure of EDG 23 given diesel 21 fails
3.150E-02	Failure of EDG 23 given diesel 21 fails
G3D	Failure of EDG 23 given EDGs 21 and 22 have failed
7.102E-02	Failure of EDG 23 given EDGs 21 and 22 have failed
G3F	Guaranteed failure of EDG 23
1.000E 00	Guaranteed failure of EDG 23
G3S	EDG 23 not required - normal power available
0.000E 00	EDG 23 not required - normal power available
A51	Failure of 480V bus 5A - bus 5 available
9.470E-06	Failure of 480V bus 5A - bus 5 available
A52	Failure of 480V bus 5A - loss of power to bus 5
5.595E-03	Failure of 480V bus 5A - loss of power to bus 5

Table 3.2-6b

EPS CAUSE TABLE (continued)

A5F Guaranteed failure of bus 5A
1.000E 00 Guaranteed failure of bus 5A
A61 Failure of 480V bus 6A - bus 6 available
9.470E-06 Failure of 480V bus 6A - bus 6 available
A62 Failure of 480V bus 6A - loss of power to bus 6
5.595E-03 Failure of 480V bus 6A - loss of power to bus 6
A6F Guaranteed failure of bus 6A
1.000E 00 Guaranteed failure of bus 6A
A21 Failure of 480V bus 2A - bus 2 available
2.708E-06 Failure of 480V bus 2A - bus 2 available
A22 Failure of 480V bus 2A - loss of power to bus 2
5.589E-03 Failure of 480V bus 2A - loss of power to bus 2
A2F Guaranteed failure of bus 2A
1.000E 00 Guaranteed failure of bus 2A
A31 2.764E-06 Failure of 480V bus 3A - bus 3 available
2.764E-06 Failure of 480V bus 3A - bus 3 available
A32 Failure of 480V bus 3A - loss of power to bus 3
5.589E-03 Failure of 480V bus 3A - loss of power to bus 3

Table 3.2-6b

EPS CAUSE TABLE
(continued)

A3F	Guaranteed failure of bus 3A
1.000E 00	Guaranteed failure of bus 3A
FO1	EDG fuel oil - one pump available
5.518E-03	EDG fuel oil - one pump available
4.581E-03	Fuel oil pump failure
9.006E-04	Fuel oil pump maintenance
3.600E-05	Operator error - restore power
FO2	EDG fuel oil - two pumps available
1.959E-04	EDG fuel oil - two pumps available
2.385E-05	Fuel oil pump failure
8.238E-06	Fuel oil pump maintenance
3.600E-05	Operator error - restore power
1.278E-04	Common cause
FO3	EDG fuel oil - three pumps available
8.014E-05	EDG fuel oil - three pumps available
1.414E-07	Fuel oil pump failure
4.068E-07	Fuel oil pump maintenance
3.600E-05	Operator error - restore power
4.359E-05	Common cause
FOF	Guaranteed failure of the EDG fuel oil system
1.000E 00	Guaranteed failure of the EDG fuel oil system

TABLE 3.2-6(c)
EPS EQUATION FILE

OG1	2	STAUXT= IPT01R * T6	$ Loss of Offsite Power: Not as an initiating event
OGF	1	OGFTOP= 1.00	$ Loss of Offsite Power: Initiating Event
Y51	1	TOP = BUS5_F+CBST5F+CB55AF+SST5_F	$ Offsite Power Available - Failure of 6.9kV Bus 5
Y51	2	BUS5_F= IPBUSO * T6	$ Bus 5 - Busbar failure
Y51	3	CBST5F= IPBKRT * T6	$ Station Service Trans Breaker to Bus 5 Transfers Position During Mission Time
Y51	4	CB55AF= IPBKRT * T6	$ 6.9KV Bus Breaker to Bus 5A Transferes Position During Mission Time
Y51	5	SST5_F= IPT01R * T6	$ Failure of the Station Service Transformer 5 During its Mission Time
Y5F	1	TOP = 1.00	$ Guarenteed Failure of 6.9KV Bus 5
Z61	1	TOP = BUS6_F + CBST6F + CB66AF + SST6_F	$ Offsite Power Available - Failure of 6.9kV Bus 6
Z61	2	BUS6_F= IPBUSO * T6	$ Bus 6 - Busbar failure
Z61	3	CBST6F= IPBKRT * T6	$ Station Service Trans. Breaker to Bus 6 Transfers position during Mission Time
Z61	4	CB66AF= IPBKRT * T6	$ 6.9KV Bus Breaker to Bus 6A Transfers Position During Mission Time
Z61	5	SST6_F= IPT01R * T6	$ Failure of the Station Service Transformer 6 During Mission Time
Z6F	1	TOP = 1.00	$ Guarenteed Failure of 6.9KV Bus 6
W21	1	TOP = BUS2_F+CBUT2F+CB22AF+SST2_F+UT2ST5	$ Offsite Power Available - Failure of 6.9kV Bus 2
W21	2	BUS2_F= IPBUSO * T6	$ Bus 2 - Busbar failure
W21	3	CBUT2F= IPBKRO	$Station Service Trans Breaker to Bus 2 Transfers Position during mission time
W21	4	CB22AF= IPBKRT * T6	$ 6.9KV Bus Breaker to Bus 2A Transfers Position During its Mission Time
W21	5	SST2_F= IPT01R * T6	$ Failure of the Station Service Transformer 2 During its Mission Time
W21	6	UT2ST5= IPBKRC	$ Tie Bkr UT3 - ST6 Failure to Close
W2F	1	TOP = 1.00	$ Guarenteed Failure of 6.9KV Bus 2
X31	1	TOP = BUS3_F+CBUT3F+CB33AF+SST3_F+UT3ST6	$ Offsite Power Available failure of 6.9KV Bus 3
X31	2	BUS3_F= IPBUSO * T6	$ Bus 3 - Busbar failure
X31	3	CBUT3F= IPBKRO	$ Unit Tie Breaker 3 Transfers Position During Its Mission Time
X31	4	CB33AF= IPBKRT * T6	$ 6.9KV Bus Breaker to Bus 3A
X31	5	SST3_F= IPT01R * T6	$ Station Service Transformer 2 Running Failure
X31	6	UT3ST6= IPBKRC	$ Tie Breaker UT3 - ST6
X32	1	X32TOP= X32_1	$ Offsite Power Available - Bus 2 failed, Failure of 6.9KV Bus 3
X3F	1	TOP = 1.00	$ Guarenteed Failure of 6.9KV bus 3
D11	1	TOP = DBUS21 + DSUPP1	$ Failure DC Bus 21, power available at charger
D11	2	DBUS21= IPBUSO * T6	$ DC Bus 21 - Busbar Failure
D11	3	DSUPP1= DCHGR1 * DBATT1	$ DC Supply - Charger and Battery Failure
D11	4	DCHGR1= IPBCHR * T6	$ Battery Charger 21 Failure During Its Mission Time
D11	5	DBATT1= IPBATR * T6 + IPBATD	$ Battery 21 Failure on Demand or During Mission Time
D12	1	TOP = DBUS21 + DBATT1	$ Failure DC Bus 21, power lost at charger
D12	2	DBUS21= IPBUSO * T6	$ DC Bus 21 - Busbar Failure
D12	3	DBATT1= IPBATR * T6 + IPBATD	$ Battery 21 Failure on Demand or During Mission Time
D1F	1	TOP = 1.00	$ Guarenteed Failure of DC bus 21
D21	1	TOP = DBUS22 + DSUPP2	$ Failure DC Bus 22, power available at charger
D21	2	DBUS22= IPBUSO * T6	$ DC Bus 22 - Busbar Failure
D21	3	DSUPP2= DCHGR2 * DBATT2	$ DC Supply - Charger and Battery Failure
D21	4	DCHGR2= IPBCHR * T6	$ Battery Charger 22 Failure During its Mission Time
D21	5	DBATT2= IPBATR * T6 + IPBATD	$ Battery 22 Failure on Demand or During Mission Time

TABLE 3.2-6(c)
EPS EQUATION FILE

D22	1 TOP = DBUS22 + DBATT2	$ Power lost at 2DC 22, power lost at
D22	2 DBUS22= IPBUSO * T6	$ DC Bus 22 - Busbar failure
D22	3 DBATT2= IPBATR * T6 + IPBATD	$ Battery 22 Failure on Demand or During Mission Time
D23	1 TOP = D23	$ Failure DC Bus 22, Given D12
D2F	1 TOP = 1.0	$ Guaranteed failure of DC bus 22.
D31	1 TOP = DBUS23 + DSUPP3 + DCSWTH	$ Failure DC bus 23, power available at charger
D31	2 DBUS23= IPBUSO * T6	$ Bus 23 - Busbar Failure
D31	3 DSUPP3= DCHGR3 * DBATT3	$ DC Supply - Charger and Battery Failure
D31	4 DCHGR3= IPBCHR * T6	$ Battery Charger 23 During Mission Time
D31	5 DBATT3= IPBATR * T6 + IPBATD	$ Battery 23 Failure on Demand or During the Mission Time
D31	6 DCSWTH= 4 * IPSW1D	$ DC Transfer Switch Failure
D32	1 TOP = DBUS23 + DBATT3 + DCSWTH	$ Failure DC bus 23, power lost at charger
D32	2 DBUS23= IPBUSO * T6	$ DC Bus 23 - Busbar Failure
D32	3 DBATT3= IPBATR * T6 + IPBATD	$ Battery 23 Failure on Demand or During the Mission Time
D32	4 DCSWTH= 4 * IPSW1D	$ DC Transfer Switch Failure
D33	1 TOP = D33	$ Failure DC bus 23, power lost at chrger and D1 or D2 have failed
D34	1 TOP = D34	$ Failure DC bus 23, power lost at chrger and D1 and D2 have failed
D3F	1 TOP = 1.0	$ Guaranteed failure of DC bus 23.
D41	1 TOP = DBUS24 + DSUPP4 + DCSWTH	$ Failure DC Bus 24, power available to charger
D41	2 DBUS24= IPBUSO * T6	$ DC Bus 24 - Busbar Failure
D41	3 DSUPP4= DCHGR4 * DBATT4	$ DC Supply - Battery and Charger Failure
D41	4 DCHGR4= IPBCHR * T6	$ Battery Charger 24 Failure During its Mission time
D41	5 DBATT4= IPBATR * T6 + IPBATD	$ Battery 24 Failure on Demand or During its Mission Time
D41	6 DCSWTH= 3 * IPSW1D	$ DC Transfer Switch Failure
D42	1 TOP = DBUS24+DBATT4+DCSWTH	$ Failure DC Bus 24, power lost at charger
D42	2 DBUS24= IPBUSO * T6	$ DC Bus 24 - Busbar Failure
D42	3 DBATT4= IPBATR * T6 + IPBATD	$ Battery 23 Failure on Demand or during the mission time
D42	4 DCSWTH= 3 * IPSW1D	$ DC Transfer Switch Failure
D43	1 TOP = D43	$ Failure DC Bus 24, Power lost at Charger and D1 or D2 or D3 have Failed
D44	1 TOP = D44	$ Failure DC Bus 24, Power lost at Charger and two DC buses have Failed
D45	1 TOP = 1.00	$ Failure DC Bus 24, Power lost at Charger and D1 and D2 and D3 have Failed
D4F	1 TOP = 1.00	$ Guaranteed Fail of DC Bus 24

TABLE 3.2-6(c)
EPS EQUATION FILE

```
G11    1 TOP                                              $ Failure of EDG 21 Single Diesel Challenged
G11    2 DG21_H= DG21_S+DG21_R                            $ Hardware failure of the EDG to start or run
G11    3 DG21_S= DGSTRT                                   $     EDG Start
G11    4 DG21_R= DG_RUN                                   $     EDG Run
G11    5 DG21_M= DG_MNT                                   $     EDG Maintenance Unavailability
G11    6 DG21_T= 0.00                                     $     EDG Testing Unavailability
G11    7 DG21_C= 0.00                                     $     EDG Common Cause Unavailability
G11    8 DG21_O= DG_OP1 + DG_OP2                          $     Operator Error Total
G11    9 DG_OP1= OPERR1                                   $       Operator Error on one EDG
G11   10 DG_OP2= MNTERR                                   $       Operator Error on Maintenance
G11   11 SWSSUP= SWN_62+SWN_67+SWSOUT                     $  Service Water Aligment
G11   12 SWOUT = SWSOUT                                   $     Service Water Valve Failure Combinations
G12    1 TOP    = G11                                     $ Falure of EDG 21-two Diesels Challenged
G13    1 TOP    = G11                                     $ Failure of EDG 21-- three Diesels Challenged
G1F    1 TOP    = 1.00                                    $ Guaranteed failure of EDG 21.
G1S    1 TOP    = 0.00                                    $ EDG 21 not required - (Normal Power Available)
G21    1 TOP    = G21                                     $ Failure EDG 22 single Diesel Challenged
G22    1 TOP    = G21                                     $ Failure of EDG 22 -two Diesels Challenged
G2A    1 TOP    = G2A                                     $ Failure of EDG 22 given EDG 21 succeeds
G2B    1 TOP    = DG2 / G11                               $ Failure of EDG 22 given EDG 21 fails
G23    1 TOP    = G2A                                     $ Failure of EDG 22, three EDGs challenged
G2C    1 TOP    = DG2 / G11                               $ Failure of EDG 22 given EDG 21 fails- Three EDGs challenged
G2F    1 TOP    = 1.00                                    $ Guarenteed failure of EDG 22
G2S    1 TOP    = 0.00                                    $ EDG 22 not reqd. Normal power available
G31    1 TOP    = G31                                     $ Failure of 23 - single EDG challenged
G32    1 TOP    = G2A                                     $ Failure of EDG 23 given EDG 21 or 22
G33    1 TOP    = (DG1-2*DG2+DG3)/((1-G11)*(1-G2A))       $ Failure of EDG 23 , Three EDG's challenged
G3B    1 TOP    = (DG2 - DG3) / ((1 - G11) * G2A)         $ Failure of EDG 23 given EDG 22 fails
G3C    1 TOP    = (DG2 - DG3) / ((1 - G11) * G2A)         $ Failure of EDG 23 given EDG 21 fails
G3D    1 TOP    = DG3 / (G11 * G2B)                       $ Failure of EDG 23 given EDG 21 and 22 have failed
G3F    1 TOP    = 1.00                                    $ Guaranteed failure of EDG 23
G3S    1 TOP    = 0.00                                    $ EDG 23 not required - normal power availble
A51    1 TOP    = BUS5AF + MCC26A + BRKR26                $ Failure 480 VAC Bus 5A - 6.9KV Bus 5 available
A51    2 BUS5AF= IPBUSO * T6                              $       Bus 5A - Busbar Failure
A51    3 MCC26A= IPBUSO * T6                              $       MCC 26A - Busbar Failure
A51    4 BRKR26= IPBKRT * T6                              $       480V AC Breaker to MCC 26A Transfers Position during its Mission Time
A52    1 TOP    = BUS5AF + MCC26A + BRKR26 + BK5A_O + BKEG1C  $ Failure 480 VAC Bus 5A - Pwr lost at 6.9KV Bus 5
A52    2 BUS5AF= IPBUSO * T6                              $       Bus 5A  - Busbar Failure
A52    3 MCC26A= IPBUSO * T6                              $       MCC 26A - Busbar Failure
A52    4 BRKR26= IPBKRT * T6                              $       480V AC Breaker to MCC 26A Transfers Position during its Mission Time
A52    5 BK5A_O= IPBKRO                                   $       480V AB Breaker to MCC 26A Opens
A52    6 BKEGTC= IPBKDC                                   $       EDG breaker to the 480V AC Bus section fails to close
A5F    1 TOP    = 1.00                                    $ Guarenteed failure of Bus 5A
A61    1 TOP    = BUS6AF + MCC26B + BRKR26                $ Failure 480 VAC Bus 6A - 6.9KV Bus 6 available
A61    2 BUS6AF= IPBUSO * T6                              $       Bus 6A - Busbar Failure
A61    3 MCC26B= IPBUSO * T6                              $       MCC 26B - Busbar Failure
A61    4 BRKR26= IPBKRT * T6                              $       MCC 26B Bkr - Breaker Transfers Position During its Mission Time
A62    1 TOP    = BUS6AF + MCC26B + BRKR26 + BK6A_O + BKEG3C  $ Failure 480 VAC Bus 6A - Power Lost at 6.9KV Bus 6
A62    2 BUS6AF= IPBUSO * T6                              $       Bus 6A - Busbar Failure
A62    3 MCC26B= IPBUSO * T6                              $       MCC 26B - Busbar Failure
A62    4 BRKR26= IPBKRT * T6                              $       MCC 26B Breaker - Transfers Position During its Mission Time
A62    5 BK6A_O= IPBKRO                                   $       MCC 26B Breaker - Fails to Open on Demand
A62    6 BKEG3C= IPBKDC                                   $       MCC 26B Breaker - Fails to Open on Demand
A6F    1 TOP    = 1.00                                    $ Guarenteed failure of Bus 6A
```

TABLE 3.2-6(c)
EPS EQUATION FILE

```
A21     1 TOP    = BUS2AF                                       $ Failure 480V Bus 2A - 6.9KV Bus 2 available
A22     1 TOP    = BUS2AF + BK2A_O + BKEG2A                     $ Failure 480V Bus 2A - Power Lost at 6.9KV Bus 2
A22     2 BUS2AF= IPBUSO * T6                                   $      Bus 2A - Busbar Failure
A22     3 BK2A_O= IPBKRO                                        $      Bus 2A Breaker Fails to Open on Demand
A22     4 BKEG2A= IPBKDC                                        $      Bus 2A Breaker Fails to Close on Denamd
A2F     1 TOP    = 1.00                                         $ Guarenteed failure of Bus 2A
A31     1 TOP    = BUS3AF                                       $ Failure 480V Bus 3A - 6.9KV Bus 3 available
A32     1 TOP    = BUS3AF + BK3A_O + BKEG2B                     $ Failure 480V Bus 3A - Pwr lost at 6.9KV Bus 3
A32     2 BUS3AF= IPBUSO * T6                                   $      Bus 3A - Busbar Failure
A32     3 BK3A_O= IPBKRO                                        $      Bus 3A Breaker Fails to Open
A32     4 BKEG2B= IPBKDC                                        $      Bus 3A Breaker Fails to Close on Demand
A3F     1 TOP    = 1.00                                         $ Guarenteed failure of Bus 3A
FO1     1 TOP    = FO1_H + FO1_M + FO1_O                        $ EDG Fuel Oil - One pump available
FO1     2 FO1_H = FO1TRN                                        $  Hardware failures EDG FOTP
FO1     3 FO1_M = IPPD11 * IPPF11                               $  Maintenance failure EDG FOTP
FO1     4 FO1_O = IPOPFO                                        $  Operator Error EDG FOTP
FO2     1 TOP    = FO2_H + FO2_M + FO2_O + FO2_C                $ EDG FOTP - two pumps available
FO2     2 FO2_H = FO1TRN * FOTTRN                               $  Hardware failure EDG FOTP's
FO2     3 FO2_M = 2 * FOP_M * (1 - FOP_M) * FO1TRN              $  Maintenance failures EDG FOTP's
FO2     4 FO2_O = IPOPFO                                        $  Operator Error EDG FOTP's
FO2     5 FO2_C = FOCC2                                         $  Common Cause Failure EDG FOTP's
FO3     1 TOP    = FO3_H + FO3_M + FO3_O + FO3_C                $ EDG FOTP - three pumps available
FO3     2 FO3_H = FO1TRN * FOTTRN * FO1TRN                      $  Hardware failure EDG FOTP's
FO3     3 FO3_M = 3*FOP_M*(1-FOP_M) * (FO1TRN * FO1TRN + FOCC2) $  Maintenance failures EDG FOTP's
FO3     4 FO3_O = IPOPFO                                        $  Operator Error EDG FOTP's
FO3     5 FO3_C = 3 * FOCC2 * FO1TRN + FOCC3                    $  Common Cause failure EDG FOTP's
FOF     1 TOP    = 1.00                                         $ Guarenteed failure of 3 EDG FOTP's
          X32_1 = BUS2_3 / W21TOP                               $ Offsite Power Available - Bus 2 failed, Failure of 6.9KV
          X31EX = BUS3_F + CBUT3F + CB33AF + SST3_F + UT3ST6    $
          BUS3_F= IPBUSO * T6                                   $
          CBUT3F= IPBKRO                                        $
          CB33AF= IPBKRT * T6                                   $
          SST3_F= IPTO1R * T6                                   $
          UT3ST6= IPBKRC                                        $
          BUS2_3= W21TOP * X31EX + CCBKR                        $
          CCBKR = IPBKRC * IPBBGC                               $
          W21TOP= BUS2_F + CBUT2F + CB22AF + SST2_F + UT2ST5    $ 6.9KV Bus 2 Failure including Breaker Failures
          UT2ST5= IPBKRC                                        $
          SST2_F= IPTO1R * T6                                   $
          BUS2_F= IPBUSO * T6                                   $
          CBUT2F= IPBKRO                                        $
          CB22AF= IPBKRT * T6                                   $
          DG1    = G11 + DG_MNT + SWSSUP                        $
          D23    = DCBUS2/DT2                                   $
          D33    = DCBUS2/D12                                   $
          D34    = DCBUS3/DCBUS2                                $
          D43    = DCBUS2/D12                                   $
          D44    = DCBUS3/DCBUS2                                $
          DCBUS2= D12 * D22 + CC2BAT + CC3BAT                   $ Failure of any two DC Buses - power lost to chargers.
          DCBUS3= D12 * D22 * D32 + CC_BAT                      $ Failure of any three DC Buses - power lost to charger.
          CC_BAT= CC2BAT * D12 + CC3BAT                         $   Common Cause
          CC2BAT= 1/3 * (IPBBAD) * ( 1-IPGBAD) * IPBATD         $   CCF of any two batteries on demand.
```

TABLE 3.2-6(c)
EPS EQS FILE

```
CC3BAT= IPBBAD * IPGBAD * IPBATD                  $   CCF of three or more batteries on demand.
D12    = DBUS21 + DBATT1                          $
DBUS21= IPBUSO * T6                               $
DBATT1= IPBATR * T6 + IPBATD                      $
D22    = DBUS22 + DBATT2                          $
DBUS22= IPBUSO * T6                               $
DBATT2= IPBATR * T6 +IPBATD                       $
D32    = DBUS23 + DBATT3 + DCSWTH                 $
DBUS23= IPBUSO * T6                               $
DBATT3= IPBATR * T6 + IPBATD                      $
DCSWTH= 4 * IPSW1D                                $
G2A    = (G11 - DG2) / (1 - G11)                  $
G2B    = DG2 / G11                                $
G11    = DGSTRT+DG_RUN+OPERR1+MNTERR+DG_MNT+SWSSUP $
G21    = DGSTRT+DG_RUN+OPERR1+MNTERR+DG_MNT+SWSSUP $
G31    = DGSTRT+DG_RUN+OPERR1+MNTERR+DG_MNT+SWSSUP $
DG2    = DG2_H + DG2_M + DG2_O + DG2_C + SWSSUP   $ Failure of 2 EDG's- 2 EDG'S available
DG2_H = SINGDG * SINGDG                           $
DG2_M = 2 * DG_MNT * (SINGDG + OPERR1 + MNTERR)   $
DG2_O = OP1DG2 + OP2DG2                           $
OP1DG2= 2 * (OPERR1 + MNTERR) * SINGDG            $
OP2DG2= OPCOUP * OPERR1 + OPMNTC * MNTERR + XX    $
XX     = 2 * OPERR1 * MNTERR                      $
DG2_C = CCDG2                                     $
DG3    = DG3_H + DG3_M + DG3_O + DG3_C + SWSSUP   $ Failure of 3 EDG's, 3 EDG's available
DG3_H = SINGDG * SINGDG * SINGDG                  $
DG3_M = 3 * DG_MNT * (ONE_DG * ONE_DG + CCDG2)    $
DG3_O = OP_1DG + OP_2DG + OP_3DG                  $
OP_1DG= 3*(OPERR1+MNTERR)*(ONE_DG*ONE_DG+CCDG2)   $
OP_2DG= 3*(OPCOUP*OPERR1+OPMNTC*MNTERR+OP2DGC)*SINGDG $
OP2DGC= OPERR1 * OPMNTC                           $
OP_3DG= OPCOUP*OPCOUP*OPERR1+OPMNTC*OPMNTC*MNTERR $
ONE_DG= SINGDG + OPERR1 + MNTERR                  $
SWSSUP= SWN_62 + SWN_67 + SWSOUT                  $
DG3_C = 3 * SINGDG * CCDG2 + CCDG3                $
SINGDG= DGSTRT + DG_RUN                           $
DGSTRT= (1 - DG_MNT) * IPD01S                     $
DG_RUN= (1 - DG_MNT) * (1 - IPD01S) * DGRNT * T6  $
DG_MNT= IPDF01 * IPDD01                           $
CCDG2 = CC2ST + CC2RN                             $
CCDG3 = CC3ST + CC3RN                             $
CC2ST = 1/2 * IPBD1S * (1 - IPGD1S) * IPD01S      $
CC3ST = IPBD1S * IPGD1S * IPD01S                  $
CC2RN = (CCR1 + 5 * CCR2) / 6                     $
CCR1  = 1/2 * IPBD1R * (1 - IPBD1R) * IPDG1R * T6 $
CCR2  = 1/2 * IPBDPR * (1 - IPBDPR) * IPDG2R * T6 $
CC3RN =  (CC3R1 + 5 * CC3R2) / 6                  $
CC3R1 = IPDG1R * IPBD1R * IPGD1R * T6             $
CC3R2 = IPDG2R * IPBDPR * IPGDPR * T6             $
DGRNT = (IPDG1R + 5 * IPDG2R) / 6                 $
FOCC2 = PMSCC2 + PMRCC2 + BKDCC2                  $
FOCC3 = PMSCC3 + PMRCC3 + BKDCC3                  $
FO1TRN= IPP11S + IPP11R * T6 + IPBKRC             $
```

TABLE 3.2-6(c)
EPS EQUATION FILE

```
PMRCC2= 1/2 * IPB11R * (1 - IPG11R) * IPP11R * T6          $
PMRCC3= IPB11R * IPG11R * IPP11R * T6                       $
PMSCC2= 1/2 * IPB11S * (1 - IPG11S) * IPP11S                $
PMSCC3= IPB11S * IPG11S * IPP11S                            $
BKDCC2= 1/2 * IPBKRB * (1 - IPBKRG) * IPBKRC                $
BKDCC3= IPBKRB * IPBKRG * IPBKRC                            $
SWSOUT= FV76T*FV76AD+FV76D*FV76AT+FV76T*FV76AT              $
FV76T = IPV05T * T6                                         $
FV76D = IPV05D                                              $
FV76AD= IPV05D                                              $
FV76AT= IPV05T * T6                                         $
OPCOUP= (1 + 19 * OPERR1) / 20                              $
OPERR1= (HEO1A * 4.0/2 ) / 720                              $
OPMNTC= (1 + 19 * MNTERR) / 20                              $
MNTERR= HEC1 * 0.05                                         $
SWN_62= IPV01T * (T6 + T2)                                  $
SWN_67= IPV01T * (T6 + T2)                                  $
T2    = 720.0 / 2.0                                         $
T6    = 6.0                                                 $
```

TABLE 3.2.7a

FCU SPLIT FRACTIONS

Split Fraction	Definition
FC4	Loss of Offsite Power or SI signal - all power available
FC5	LOSP or SI - Loss of power at Bus 2A, 3A, or 6A
FC6	LOSP or SI - Loss of power either at Bus 5A or at Buses 2A & 3A
FCF	Guaranteed failure of the FCU System

TABLE 3.2.7b

FCU CAUSE TABLE

FC4	Loss of Offsite Power or SI signal - all power available
9.327E-05	Loss of Offsite Power or SI signal - all power available
1.580E-06	Hardware
1.846E-06	Maintenance Contribution
8.984E-05	Common Cause Contribution
FC5	LOSP or SI - Loss of power at Bus 2A, 3A, or 6A
3.405E-04	LOSP or SI - Loss of power at Bus 2A, 3A, or 6A
9.476E-05	Hardware
1.727E-04	Maintenance Contribution
7.304E-05	Common Cause Contribution
FC6	LOSP or SI - Loss of power either at Bus 5A or at Buses 2A & 3A
2.294E-02	LOSP or SI - Loss of power either at Bus 5A or at Buses 2A & 3A
1.110E-02	Hardware
1.177E-02	Maintenance Contribution
5.763E-05	Common Cause Contribution
FCF	Guaranteed failure of the FCU System
1.000E 00	Guaranteed failure of the FCU System

TABLE 3.2-7(c)
FCS EQUATION FILE

```
FC4     1 TOP    = FC4_H + FC4_M + FC4_C                                 $ Loss of Offsite Power or SI signal -all power available
FC4     2 FC4_H  = FCU21S * FCU22S * (FCU23S + FCU24S + FCU25S) + FC4H1   $  Hardware unavailability
FC4       FC4H1  = (FCU21S + FCU22S)* FCU23S *(FCU24S + FCU25S) + FC4H2   $  Hardware
FC4       FC4H2  = (FCU21S + FCU22S + FCU23S) * FCU24S * FCU25S + FC4H3   $  Hardware
FC4       FC4H3  = SW_RET                                                 $  Hardware
FC4     3 FC4_M  = F21M + F22M + F23M + F24M + F25M                       $  Maintenance - total
FC4     4 F21M   = FCU_M * (FCU22S * (FCU23S + FCU24S + FCU25S) + F21M1)  $   Maintenance FCU-21
FC4       F21M1  = FCU23S * (FCU24S + FCU25S) + FCU24S * FCU25S           $
FC4     5 F22M   = FCU_M * (FCU21S * (FCU23S + FCU24S + FCU25S) + F22M1)  $   Maintenance FCU-22
FC4       F22M1  = FCU23S * (FCU24S + FCU25S) + FCU24S * FCU25S           $
FC4     6 F23M   = FCU_M * (FCU21S * (FCU22S + FCU24S + FCU25S) + F23M1)  $   Maintenance FCU-23
FC4       F23M1  = FCU22S * (FCU24S + FCU25S) + FCU24S * FCU25S           $
FC4     7 F24M   = FCU_M * (FCU21S * (FCU22S + FCU23S + FCU25S) + F24M1)  $   Maintenance FCU-24
FC4       F24M1  = FCU22S * (FCU23S + FCU25S) + FCU23S * FCU25S           $
FC4     8 F25M   = FCU_M * (FCU21S * (FCU22S + FCU23S + FCU24S) + F25M1)  $   Maintenance FCU-25
FC4       F25M1  = FCU22S * (FCU23S + FCU24S) + FCU23S * FCU24S           $
FC4     9 FC4_C  = FC4CCF + FC4CCV + FC4TCV                               $  Common cause failure
FC4    10 FC4CCF= 10/4*IPF01S*IPBF1S*(1-IPGF1S)*3*(FCU21S+FCU_M)+FC4CF1   $  Common cause failure of the fan motors
FC4       FC4CF1= 10/4*IPFNR1*IPF01R*(1-IPGF1R)*3*(FCU21S+FCU_M)+FC4CF2   $
FC4       FC4CF2= IPF01S * IPBF1S * IPGF1S + IPFNR1 * IPBF1R * IPGF1R     $
FC4    11 FC4CCV= 40/9 *IPV05D*IPVB5D*(1-IPVG5D)*3*(FCU21S+FCU_M)+FC4V1   $ CCF of butterfly valves
FC4       FC4V1 = IPV05D * IPVB5D * IPVG5D                                $
FC4    12 FC4TCV= IPV05D * IPVB5D                                         $ CCF of service water return AOV's
FC5     1 TOP    = FC5_H + FC5_M + FC5_C                                 $ LOSP or SI - Loss of power loss at 2A, 3A, or 6A
FC5     2 FC5_H  = FCU21S * (FCU22S + FCU23S + FCU24S) + FC5H1            $  Hardware unavailability
FC5       FC5H1  = FCU22S * (FCU23S + FCU24S) + FCU23S * FCU24S + SW_RET  $
FC5     3 FC5_M  = F21M + F22M + F23M + F24M                              $  Maintenance - total
FC5     4 F21M   = FCU_M * (FCU22S + FCU23S + FCU24S)                     $   Maintenance FCU-21
FC5     5 F22M   = FCU_M * (FCU21S + FCU23S + FCU24S)                     $   Maintenance FCU-22
FC5     6 F23M   = FCU_M * (FCU21S + FCU22S + FCU24S)                     $   Maintenance FCU-23
FC5     7 F24M   = FCU_M * (FCU21S + FCU22S + FCU23S)                     $   Maintenance FCU-24
FC5     8 FC5_C  = FC5CCF + FC5CCV + FC5TCV                               $  Common cause failure
FC5     9 FC5CCF= IPFNR1 * IPBF1R * IPGF1R + FC5CF1 + FC5CF2              $  Common cause failure of the fan motors
FC5       FC5CF1= 6/4 * IPFNR1 * IPBF1R * (1-IPGF1R) *2*(FCU21S+FCU_M)    $
FC5       FC5CF2= 6/4 * IPF01S * IPBF1S * (1-IPGF1S) *2*(FCU21S+FCU_M)    $
FC5    10 FC5CCV= IPV05D * IPVB5D * IPVG5D + FC5CV1                       $  CCF of the butterfly valves
FC5       FC5CV1= 24/9 * IPV05D * IPVB5D * (1-IPVG5D) *2*(FCU21S+FCU_M)   $
FC5    11 FC5TCV= IPV05D * IPVB5D                                         $ CCF of service water return AOV's
FC6     1 TOP    = FC6_H + FC6_M + FC6_C                                 $ LOSP or SI - Loss of power loss at 5A or 2A & 3A
FC6     2 FC6_H  = FCU21S + FCU22S + FCU25S + SW_RET                      $  Hardware unavailability
FC6     3 FC6_M  = F21M + F22M + F25M                                     $  Maintenance - total
FC6     4 F21M   = FCU_M                                                  $   Maintenance FCU-21
FC6     5 F22M   = FCU_M                                                  $   Maintenance FCU-22
FC6     6 F25M   = FCU_M                                                  $   Maintenance FCU-25
FC6     7 FC6_C  = IPV05D * IPVB5D                                        $ CCF of service water return
                                                                            AOV's
FCF     1 TOP    = 1.00                                                   $ Guaranteed failure of the FCU System
```

TABLE 3.2-7(C)
FCU EQUATION FILE

```
SW RET= TV1104 * TV1105                                          $  Service water return AOV's
TVT104= IPV05D                                                   $  TCV-1104 fails to open on demand
TV1105= IPV05D                                                   $  TCV-1105 fails to open on demand
FCU21S= IPF01S + FCU21R                                          $  FCU-21 start and run
FCU21R= (IPF01R + 8 * IPV01T + 2 * IPH01L) * T1 + 2 * IPV05D     $  FCU-21 run (6 MOV's, 2 man.vlvs, 3  butterfly valves)
FCU22S= IPF01S + FCU22R                                          $  FCU-22 start and run
FCU22R= (IPF01R + 8 * IPV01T + 2 * IPH01L) * T1 + 2 * IPV05D     $  FCU-22 run (6 MOV's, 2 manual valves, 3 butterfly valves)
FCU23S= IPF01S + FCU23R                                          $  FCU-23 start and run
FCU23R= (IPF01R + 8 * IPV01T + 2 * IPH01L) * T1 + 2 * IPV05D     $  FCU-23 run (6 MOV's, 2 manual valves, 3 butterfly valves)
FCU24S= IPF01S + FCU24R                                          $  FCU-24 start and run
FCU24R= (IPF01R + 8 * IPV01T + 2 * IPH01L) * T1 + 2 * IPV05D     $  FCU-24 run (6 MOV's, 2 manual valves, 3 butterfly valves)
FCU25S= IPF01S + FCU25R                                          $  FCU-25 start and run
FCU25R= (IPF01R + 8 * IPV01T + 2 * IPH01L) * T1 + 2 * IPV05D     $  FCU-25 run (6 MOV's, 2 manualvalves, 3 butterfly valves)
FCU M = IPFF01 * IPFD01                                          $  Maintenance unavailability - FC units
IPFNR1= IPF01R * T1                                              $
T1    = 24.0                                                     $  Mission time
```

TABLE 3.2-8a

HPIS SPLIT FRACTIONS

Split Fraction	Boundary Condition
RW1	RWST, 1 hour mission time
RW2	RWST, 6 hour mission time
RWF	RWST, Guaranteed failure
HP3	HPI, all power available
HP4	HPI, power lost to buses 2A and 3A
HPD	HPI, power lost to one bus (5A or 6A)
HP5	HPI, power lost to 2A, 3A, & either 5A or 6A
HPF	Guaranteed failure of the HPI function
O11	Primary Bleed only (does not include HPI).
O1F	Primary Bleed only - guaranteed failure.
O21	Primary Bleed only (ATWS) - All power available
O2F	Primary Bleed Only (ATWS) - guaranteed failure

TABLE 3.2-8b

HPIS CAUSE TABLE

RW1	Refueling Water Storage Tank, 1 hour mission time.
5.207E-05	Refueling Water Storage Tank, 1 hour mission time.
RW2	Refueling water storage tank, 6 hour mission time.
5.383E-05	Refueling water storage tank, 6 hour mission time.
RWF	Refueling Water Storage Tank, guaranteed failure.
1.000E+00	Refueling Water Storage Tank, guaranteed failure.
HP3	High Pressure Injection - all power available
7.134E-04	HPI, all power available.
1.975E-04	Hardware Contribution
1.075E-04	Pumps
1.455E-15	Injection paths
5.512E-06	Maintenance Contribution
2.740E-06	Maintenance - Pump 21
3.092E-08	Maintenance - Pump 22
2.740E-06	Maintenance - Pump 23
5.104E-04	Common Cause Contribution
HP4	High Pressure Injection - Power lost to Buses 2A and 3A
7.185E-04	HPI, Power Lost to Buses 2A and 3A.
2.094E-04	Hardware Contribution
1.194E-04	Pumps
1.455E-15	Injection paths
5.790E-06	Maintenance total
2.895E-06	Maintenance - Pump 21
2.895E-06	Maintenance - Pump 23
5.032E-04	Common Cause Contribution

TABLE 3.2-8b

HPIS CAUSE TABLE
(continued)

HPD	**High Pressure Injection - Power Lost to Bus 5A or 6A**
1.008E-03	HPI, power lost to one bus (5A or 6A).
2.201E-04	Hardware Contribution
1.300E-04	Pumps
1.455E-15	Injection paths
2.851E-04	Maintenance total
2.821E-04	Maintenance - Pump 21
3.010E-06	Maintenance - Pump 22
5.032E-04	Common Cause Contribution
HP5	**High Pressure Injection - Power Lost to buses 2A, 3A and either 5A or 6A**
1.103E-02	HPI, power lost to buses 2A, 3A, & 5A or 6A
1.075E-02	Hardware Contribution
1.066E-02	Pumps
3.398E-08	Injection paths
2.821E-04	Maintenance total
0.000E+00	Common cause
HPF	**Guaranteed failure of High Pressure Injection**
1.000E+00	Guaranteed failure of the HPI function.
O11	**Primary bleed only (does not include HP).**
1.788E-02	Primary bleed only (does not include HP).
O1F	**Primary bleed only guaranteed failure.**
1.000E+00	Primary bleed only - guaranteed failure.
O21	**Primary bleed for SI boration - ATWS.**
1.108E-01	Primary bleed for SI boration - ATWS.
O2F	**Primary bleed (ATWS) - guaranteed failure.**
1.000E+00	Primary bleed (ATWS) - guaranteed failure.

TABLE 3.2-8(c)
HPIS EQUATION FILE

```
RW1    1 TOP   = IPTNK3 * (T5 + T4) + IPV01T * (T2 + T4)           $ Refueling water storage tank - 1 hour
RW2    1 TOP   = IPTNK3 * (T5 + T1) + IPV01T * (T2 + T1)           $ Refueling water storage tank - 6 hours
RWF    1 TOP   = 1.0                                               $ Guaranteed failure of the RWST
HP3    1 HP3TOP= HP3_H + HP3_M + HP3_C                             $ High Pressure Injection -  all power available
HP3    2 HP3_H = BLOCKA + PMP_3 + INJ_P                            $  Hardware
HP3    3 PMP_3 = PMP_31 + PMP_32 + PMP_33 + PMP_34                 $    Pumps
HP3      PMP_31= PUMP21 * PUMP22 * PUMP23 - P21 * P23 * PUMP22     $    Pumps
HP3      PMP_32= PUMP21 * (PMP_2A + PUMP22) * LOOP2 * LOOP4        $    Pumps and Loops
HP3      PMP_33= PUMP23 * (PMP_2B + PUMP22) * LOOP1 * LOOP3        $    Pumps and Loops
HP3      PMP_34= (P21 + VLV21 * PMP_2B) * (P23 + VLV23 * PMP_2A)   $    Pumps and Valves
HP3    4 INJ_P = LOOP1 * LOOP2 * LOOP3 * LOOP4                     $    Injection paths
HP3    5 HP3_M = PMP21M + PMP22M + PMP23M                          $  Maintenance total
HP3    6 PMP21M= PMP_M * (P23 + VLV23 * PUMP22 + PM21M1 + PM21M2)  $   Maintenance pump 21
HP3      PM21M1= VLV23 * LOOP1 * LOOP3 + VLV23 * PMP_2A            $  Maintenance pump 21
HP3      PM21M2= (PUMP22 + PMP_2A) * LOOP2 * LOOP4                 $   Maintenance
HP3    7 PMP22M= PMP_M * (PUMP21 * PUMP23 + PM22M1)                $    Maintenance pump 22
HP3      PM22M1= PUMP21 * LOOP2 * LOOP4 + PUMP23 * LOOP1 * LOOP3   $    Maintenance
HP3    8 PMP23M= PMP_M * (P21 + VLV21 * PUMP22 + PM23M1 + PM23M2)  $    Maintenance pump 23
HP3      PM23M1= VLV21 * LOOP2 * LOOP4 + VLV21 * PMP_2B            $    Maintenance
HP3      PM23M2= (PUMP22 + PMP_2B) * LOOP1 * LOOP3                 $    Maintenance
HP3    9 HP3_C = BETAS * IPP03S * (GAMMAS + 1/2 * (1-GAMMAS)) + HP3_C1$ Common cause
HP3      HP3_C1= BETAR * IPP03R * (GAMMAR + 1/2*(1-GAMMAR))*T1+HP3_C2 $   Common cause
HP3      HP3_C2= (HP3C21 + HP3C22) * (HP3C23 + HP3C24)             $   Common cause
HP3      HP3C21= 1/2 * BETAS * (1-GAMMAS) * IPP03S                 $   Common cause
HP3      HP3C22= 1/2 * BETAR * (1-GAMMAR) * IPP03R * T1            $   Common cause
HP3      HP3C23= PUMP21 + PUMP23 + 2 * PMP_M                       $   Common cause
HP3      HP3C24= LOOP2 * LOOP4 + LOOP1 * LOOP3                     $   Common cause
HP3      PUMP21= IPP03S*(1-IPB03S) + CV849A + MV850A+MV848A+IPP03R*T1 $  Unavailability - Pump 21
HP3      P21   = IPP03S*(1-IPB03S) + MV848A + IPP03R * T1          $    Common cause
HP3      VLV21 = CV849A + MV850A + VOP21                           $    Common cause
HP3      PUMP22= IPP03S*(1-IPB03S) + CV5220 + MV887A+MV887B+IPP03R*T1 $  Unavailability - Pump 22
HP3      PUMP23= IPP03S*(1-IPB03S) + CV849B + MV850B+MV848B+IPP03R*T1 $  Unavailability - Pump 23
HP3      P23   = IPP03S*(1-IPB03S) + MV848A + IPP03R * T1          $      Common cause
HP3      VLV23 = CV849A + MV850A + VOP23                           $      Common cause
HP4    1 HP4TOP= HP4_H + HP4_M + HP4_C                             $ High Pressure Injection, Power lost to Buses 2A and 3A
HP4    2 HP4_H = BLOCKA + PMP_4 + INJ_P                            $  Hardware
HP4    3 PMP_4 = PUMP21 * PUMP23 + PMP_41                          $   Pumps
HP4      PMP_41= PUMP21 * LOOP2 * LOOP4 + PUMP23 * LOOP1 * LOOP3   $   Hardware
HP4    4 INJ_P = LOOP1 * LOOP2 * LOOP3 * LOOP4                     $   Injection paths
HP4    5 HP4_M = PMP21M + PMP23M                                   $  Maintenance total
HP4    6 PMP21M= PMP_M * (PUMP23 + LOOP2 * LOOP4)                  $   Maintenance pump 21
HP4    7 PMP23M= PMP_M * (PUMP21 + LOOP1 * LOOP3)                  $   Maintenance pump 23
HP4    8 HP4_C = HP4_C1 + HP4_C2                                   $  Common cause
HP4      HP4_C1= BETAS * (1/2 * (1-GAMMAS) + GAMMAS) * IPP03S      $    Common cause
HP4      HP4_C2= BETAR * (1/2 * (1-GAMMAR) + GAMMAR) * IPP03R * T1 $    Common cause
HP4      PUMP21= IPP03S*(1-IPB03S/2)+CV849A+MV850A+MV848A+IPP03R*T1+X $ Unavailability - Pump 21
HP4      X     = VOP21                                             $
HP4      PUMP23= IPP03S*(1-IPB03S/2)+CV849B+MV850B+MV848B+IPP03R*T1+X $ Unavailability - Pump 23
HP4      X     = VOP23                                             $
```

TABLE 3.2-8(c)
HPIS EQUATION FILE

```
HPD   1 HPDTOP= HPD_H + HPD_M + HPD_C                               $ High Pressure Injection - Power Lost to one buses (5A or 6A)
HPD   2 HPD_H = BLOCKA + PMP_D + INJ_P                              $  Hardware
HPD   3 PMP_D = PUMP21 * (PUMP22 + PMP_2B + LOOP2 * LOOP4) + PMP_D1 $ Pumps (NOTE MV851A assumed to close on loss of bus 6A)
HPD     PMP_D1= (PUMP22 + PMP_2B) * LOOP1 * LOOP3                   $
HPD   4 INJ_P = LOOP1 * LOOP2 * LOOP3 * LOOP4                       $   Injection paths
HPD   5 HPD_M = PMP21M + PMP22M                                     $  Maintenance total
HPD   6 PMP21M= PMP_M                                               $   Maintenance pump 21
HPD   7 PMP22M= PMP_M * (PUMP21 + LOOP1 * LOOP3)                    $   Maintenance pump 22
HPD   8 HPD_C = HPD_C1 + HPD_C2                                     $  Common cause
HPD     HPD_C1= BETAS * (1/2 * (1-GAMMAS) + GAMMAS) * IPP03S        $    Common cause failure to start
HPD     HPD_C2= BETAR * (1/2 * (1-GAMMAR) + GAMMAR) * IPP03R * T1   $    Common cause failure to run
HPD     PUMP21= IPP03S + CV849A + MV850A+MV848A +IPP03R * T1 + VOP21 $  Unavailability - Pump 21
HPD     PUMP22= IPP03S + CV5220 + MV887A + MV887B + IPP03R * T1     $  Unavailability - Pump 22
HPD     PUMP23= IPP03S + CV849B + MV850B + MV848B + IPP03R*T1+VOP23 $  Unavailability - Pump 23
HP5   1 HP5TOP= HP5_H + HP5_M + HP5_C                               $ High Pressure Injection, Power Lost to buses 2A, 3A and either 5A or 6A.
HP5   2 HP5_H = BLOCKA + PMP_5 + INJ_P                              $  Hardware
HP5   3 PMP_5 = PUMP21                                              $   Pumps
HP5   4 INJ_P = LOOP1 * LOOP3                                       $   Injection paths
HP5   5 HP5_M = PMP_M                                               $  Maintenance total
HP5   6 HP5_C = 0.00                                                $  Common cause
HP5     PUMP21= IPP03S + CV849A + MV850A + MV848A + IPP03R*T1+VOP21 $  Unavailability - Pump 21
HPF   1 HPF   = 1.00                                                $ Guaranteed failure of the High Pressure Injection function
O11   1 O11   = IPOPFB + 2 * IPV10D + 2 * IPV04D                    $ Primary bleed only (does not include High Pressure Injection)
O1F   1 O1F   = 1.00                                                $ Primary Bleed only - Guarenteed failure
O21   1 O21TOP= IPOPSB + 2 * IPV10D + 2 * IPV04D                    $ Primary bleed only (ATWS) - All power available
O2F   1 O2F   = 1.00                                                $ Primary Bleed only (ATWS) - guaranteed failure
```

TABLE 3.2-8(c)
HPIS EQS FILE

```
BLOCKA= MV1810 + CV847                          $ RWST to HPI pumps
LOOP1 = MV856A + CV857E + CV857J + CV897A       $  Injection path RCS loop 1
LOOP2 = MV856D + CV857H + CV857D                $  Injection path RCS loop 2
LOOP3 = MV856E + CV857L + CV857K + CV897C       $  Injection path RCS loop 3
LOOP4 = MV856C + CV857C + CV857G                $  Injection path RCS loop 4
MV850A= IPV01T * T2                             $  MOV 850A (locked open)
MV850B= IPV01T * T2                             $  MOV 850B (locked open)
MV887A= IPV01T * T2                             $  MOV 887A
MV887B= IPV01T * T2                             $  MOV 887B
MV1810= IPV01T * T2                             $  MOV 1810
MV856A= IPV01T * T2                             $  MOV 856A
MV856C= IPV01T * T2                             $  MOV 856C
MV856D= IPV01T * T2                             $  MOV 856D
MV856E= IPV01T * T2                             $  MOV 856E
PMP_2A= IPV01T * T2 + CV852A + VOP226           $  MOV 851A and CV 852A and variable orifice
PMP_2B= IPV01T * T2 + CV852B + VOP225           $  MOV 851B and CV 852B and variable orifice
MV848A= IPV01T * T2                             $  MV 848A
MV848B= IPV01T * T2                             $  MV 848B
VOP21 = IPV01T * T2                             $  Variable orifice transfers closed
VOP23 = IPV01T * T2                             $  Variable orifice transfers closed
VOP226= IPV01T * T2                             $  Variable orifice transfers closed
VOP225= IPV01T * T2                             $  Variable orifice transfers closed
CV847 = IPV02D                                  $  Check valve 847
CV849A= IPV02D                                  $  Check valve 849A
CV849B= IPV02D                                  $  Check valve 849B
CV852A= IPV02D                                  $  Check valve 852A
CV852B= IPV02D                                  $  Check valve 852B
CV857C= IPV02D                                  $  Check valve 857C
CV857D= IPV02D                                  $  Check valve 857D
CV857E= IPV02D                                  $  Check valve 857E
CV857G= IPV02D                                  $  Check valve 857G
CV857H= IPV02D                                  $  Check valve 857H
CV857J= IPV02D                                  $  Check valve 857J
CV857K= IPV02D                                  $  Check valve 857K
CV857L= IPV02D                                  $  Check valve 857L
CV897A= IPV02D                                  $  Check valve 897A
CV897C= IPV02D                                  $  Check valve 897C
CV5220= IPV02D                                  $  Check valve 5220
BETAS = IPB03S                                  $  Beta factor, motor-driven pumps start
BETAR = IPB03R                                  $  Beta factor, HPI pumps run
GAMMAS= IPG03S                                  $  Gamma factor, motor-driven pumps start
GAMMAR= IPG03R                                  $  Gamma factor, HPI pumps run
PMP_M = IPPF03 * IPPD03                         $  Maintenance unavailability
T1    = 24                                      $  Mission time - 6 hours
T2    = 2190 / 2                                $  One half quarterly test interval
T4    = 1.0                                     $  Mission time - 1 hour
T5    = 8.0 / 2                                 $  Time to detect RWST faults
```

TABLE 3.2-9a

LPIS SPLIT FRACTIONS

Split Fraction	Definition
LP1	Low pressure injection (LPI) power at all buses.
LP2	LPI - Loss of power to bus 5A.
LP3	LPI - Loss of power to bus 3A.
LP4	LPI - Loss of power to bus 6A (or 3A and 5A).
LPF	Guaranteed failure of LPI.
LI1	Low pressure injection (LATE) power at all buses.
LI2	LII - Loss of power to bus 5A.
LI3	LII - Loss of power to bus 3A.
LI4	LII - Loss of power to bus 6A (or 3A and 5A).
LIF	Guaranteed failure of LII.

TABLE 3.2-9b

LPIS CAUSE TABLE

LP1	**Low Pressure Injection - Power available on all buses**
1.176E-03	LPI - Power available on all buses
3.250E-04	Hardware contribution
8.980E-05	Single event Block A
8.980E-05	Single event Block D
1.421E-04	Double event - Pumps
3.255E-06	Double event - Heat Exchangers
7.507E-05	Single injection path
4.778E-05	Maintenance LPI pumps
0.000E+00	Test contribution
8.034E-04	Common Cause
LP2	**Low Pressure Injection - Loss of power to bus 5A**
2.863E-03	LPI - loss of power to bus 5A
2.015E-03	Hardware
1.690E-03	Single heat exchanger train
4.868E-05	Maintenance LPI pumps
7.994E-04	Common Cause
LP3	**Low Pressure Injection - Loss of power to bus 3A**
1.364E-02	LPI - loss of power to bus 3A
1.150E-02	Hardware
1.132E-02	Single pump train
2.126E-03	Maintenance LPI pumps
1.564E-05	Common Cause
LP4	**Low Pressure Injection - Loss of power to bus 6A (or 3A and 5A)**
1.538E-02	LPI - loss of power to bus 6A (or 3A and 5A)
1.326E-02	Hardware
2.120E-03	Maintenance LPI pumps
LPF	**Guaranteed failure of the LPI function**
1.000E+00	Guaranteed failure of the LPI function

TABLE 3.2-9b

LPIS CAUSE TABLE
(continued)

LI1	Late Low Pressure Injection - Power on all buses
1.176E-03	Late LPI - Power available on all buses
3.250E-04	Hardware contribution
8.980E-05	Single event Block A
8.980E-05	Single event Block D
1.421E-04	Double event pumps
3.255E-06	Double event heat exchangers
7.507E-05	Single injection path
4.778E-05	Maintenance LII pumps
0.000E+00	Test contribution
8.034E-04	Common Cause
LI2	Late Low Pressure Injection - Loss of power to bus 5A
2.863E-03	Late LPI - loss of power to bus 5A
2.015E-03	Hardware
1.690E-03	Single heat exchanger train
4.868E-05	Maintenance LPI pumps
7.994E-04	Common Cause
LI3	Late Low Pressure Injection - Loss of power to bus 3A
1.364E-02	Late LPI - loss of power to bus 3A
1.150E-02	Hardware
1.132E-02	Single pump train
2.126E-03	Maintenance LPI pumps
1.564E-05	Common Cause
LI4	Late Low Pressure Injection - Loss of power to bus 6A (or 3A and 5A)
1.538E-02	Late LPI - loss of power to bus 6A (or 3A and 5A)
1.326E-02	Hardware
2.120E-03	Maintenance LPI pumps
LIF	Guaranteed failure of Late Low Pressure Injection
1.000E 00	Guaranteed failure of the Late LPI function

TABLE 3.2-9(c)
LPIS EQUATION FILE

```
LP1    1 LP1TOP= LP1_H + LP1_M + LP1_T + LP1_C + LP1_OP          $ Low Pressure Injection (LPI), power at all buses
LP1    2 LP1_H = BLOCKA + PMP21 * PMP22 + BLOCKD + HX_21*HX_22 +INJ_P $  Hardware Contribution
LP1      INJ_P = 3 * PATHA * PATHA                                $   Injection paths (need 2 loops, 1 disabled by large LOCA)
LP1    3 SING1 = BLOCKA                                           $   Single event Block A
LP1    4 SING2 = BLOCKD                                           $   Single event Block D
LP1    5 PUMPS = PMP21 * PMP22                                    $   Double event pumps
LP1    6 HEATXS= HX_21 * HX_22                                    $   Double event heat exchangers
LP1    7 INJECT= PATHA                                            $    Single injection path
LP1    8 LP1_M = 2 * PMP21 * MN_PMP                               $  Maintenance, LPI pumps and heat  exchangers
LP1    9 LP1_T = 0.00                                             $  Test contribution
LP1   10 LP1_C = IPVB4D*IPV04D + IPB04S * IPP04S + IPB04R * IPP04R*T1 $  Common Cause (MOV's 746 and 747, pumps start and run)
LP1   11 LP1_OP= 0.00                                             $  Operator action
LP2    1 LP2TOP= LP2_H + LP2_M + LP2_C                            $ LPI - loss of power to bus 5A
LP2    2 LP2_H = BLOCKA + PMP21 * PMP22 + BLOCKD + HX_21 + INJ_P  $  Hardware
LP2      INJ_P = 3 * PATHA * PATHA                                $
LP2    3 SHEATX= HX_21                                            $   Single heat exchanger train
LP2    4 LP2_M = 2 * PMP21 * MN_PMP                               $  Maintenance, LPI pumps and heat exchangers
LP2    5 LP2_C = IPB04S * IPP04S + IPB04R * IPP04R * T1           $  Common Cause
LP3    1 LP3TOP= LP3_H + LP3_M + LP3_C                            $ LPI - loss of power to bus 3A
LP3    2 LP3_H = BLOCKA + PMP22 + BLOCKD + HX_21 * HX_22 + INJ_P  $  Hardware
LP3      INJ_P = 3 * PATHA * PATHA                                $
LP3    3 SPUMP = PMP22                                            $   Single pump train
LP3    4 LP3_M = MN_PMP                                           $  Maintenance, LPI pumps and heat exchangers
LP3    5 LP3_C = IPVB4D * IPV04D                                  $  Common Cause
LP4    1 LP4TOP= LP4_H + LP4_M                                    $ LPI - loss of power to bus 6A or (3A and 5A)
LP4    2 LP4_H = BLOCKA + PMP22 + BLOCKD + HX_22 + 3 * PATHA * PATHA $  Hardware
LP4    3 LP4_M = MN_PMP                                           $  Maintenance, LPI pumps and heat exchangers
LPF    1 LPF   = 1.00                                             $ Guaranteed failure of the LPI function
LI1    1 LI1TOP= LI1_H + LI1_M + LI1_T + LI1_C + LI1_OP          $ Low pressure injection (Late) power at all buses
LI1    2 LI1_H = BLOCKA + PMP21 * PMP22 + BLOCKD + HX_21*HX_22 + INJ_P$  Hardware Contribution
LI1      INJ_P = 3 * PATHA * PATHA                                $   Injection paths (need 2 loops, 1 disabled by large LOCA)
LI1    3 SING1 = BLOCKA                                           $   Single event Block A
LI1    4 SING2 = BLOCKD                                           $   Single event Block D
LI1    5 PUMPS = PMP21 * PMP22                                    $   Double event pumps
LI1    6 HEATXS= HX_21 * HX_22                                    $   Double event heat exchangers
LI1    7 INJECT= PATHA                                            $   Single injection path
LI1    8 LI1_M = 2 * PMP21 * MN_PMP                               $  Maintenance, LII pumps and heat exchangers
LI1    9 LI1_T = 0.00                                             $  Test contribution
LI1   10 LI1_C = IPVB4D*IPV04D + IPB04S * IPP04S + IPB04R * IPP04R*T1 $  Common Cause (MOV's 746 and 747, pumps start and run)
LI1   11 LI1_OP= 0.00                                             $  Operator action
LI2    1 LI2TOP= LI2_H + LI2_M + LI2_C                            $ LII - loss of power to bus 5A
LI2    2 LI2_H = BLOCKA + PMP21 * PMP22 + BLOCKD + HX_21 + INJ_P  $  Hardware
LI2      INJ_P = 3 * PATHA * PATHA                                $
LI2    3 SHEATX= HX_21                                            $   Single heat exchanger train
LI2    4 LI2_M = 2 * PMP21 * MN_PMP                               $  Maintenance, LII pumps and heat exchangers
LI2    5 LI2_C = IPB04S * IPP04S + IPB04R * IPP04R * T1           $  Common Cause
LI3    1 LI3TOP= LI3_H + LI3_M + LI3_C                            $ LII - loss of power to bus 3A
LI3    2 LI3_H = BLOCKA + PMP22 + BLOCKD + HX_21 * HX_22 + INJ_P  $  Hardware
LI3      INJ_P = 3 * PATHA * PATHA                                $
LI3    3 SPUMP = PMP22                                            $   Single pump train
LI3    4 LI3_M = MN_PMP                                           $  Maintenance, LII pumps and heat  exchangers
LI3    5 LI3_C = IPVB4D * IPV04D                                  $  Common Cause
```

TABLE 3.2-9(c)
LPIS EQUATION FILE

```
LI4      1 LI4TOP= LI4_H + LI4_M                                      $ LII - loss of power to bus 6A (or 3A and 5A)
LI4      2 LI4_H = BLOCKA + PMP22 + BLOCKD + HX_22 + 3 * PATHA * PATHA $  Hardware
LI4      3 LI4_M = MN_PMP                                             $  Maintenance, LII pumps and heat exchangers
LIF      1 LIF   = 1.00                                               $ Guaranteed failure of the LII function
           BLOCKA= MOV882 + CV881                                     $  RWST suction path
           BLOCKD= MOV744 + CV741A                                    $  Pump discharge path
           PATHA = CV838A + CV897A                                    $  Single low pressure injection path
           HX_21 = MV742 + MOV638 + MOV747 + HX21_F                   $  Heat exchanger 21 contribution
           HX_22 = MV745A + MV745B + MOV640 + MOV746 + HX22_F         $  Heat exchanger 22 contribution
           PMP21 = IPP04S + IPP04R * T1 + MV735A + MV739A + CV738A    $  RHR pump 21
           PMP22 = IPP04S + IPP04R * T1 + MV735B + MV739B + CV738B    $  RHR pump 22
           HX21_F= IPH01L * T1                                        $  RHR heat exchanger failure
           HX22_F= IPH01L * T1                                        $  RHR heat exchanger failure
           MN_PMP= IPPF04 * IPPD04                                    $  RHR pump maintenance unavailability
           CV881 = IPV02D                                             $  Check valve 881
           CV741A= IPV02D                                             $  Check valve 741A
           CV897A= IPV02D                                             $  Check valve 897A
           CV838A= IPV02D                                             $  Check valve 838A
           CV738A= IPV02D                                             $  Check valve 738A
           CV738B= IPV02D                                             $  Check valve 738B
           MOV882= IPV01T * T2                                        $  MOV 882
           MOV744= IPV01T * T2                                        $  MOV 744
           MOV638= IPV01T * T2                                        $  MOV 638
           MOV640= IPV01T * T2                                        $  MOV 640
           MV745A= IPV01T * T2                                        $  MOV 745A
           MV745B= IPV01T * T2                                        $  MOV 745B
           MOV747= IPV04D + IPV01T * T1                               $  MOV 747
           MOV746= IPV04D + IPV01T * T1                               $  MOV 746
           MV735A= IPV01T * T2                                        $  Manual valve 735A
           MV735B= IPV01T * T2                                        $  Manual valve 735B
           MV739A= IPV01T * T2                                        $  Manual valve 739A
           MV739B= IPV01T * T2                                        $  Manual valve 739B
           MV742 = IPV01T * T2                                        $  Manual valve 742
           T1    = 6                                                  $  Mission time
           T2    = 2190 / 2                                           $  Test interval - quarterly
```

TABLE 3.2-10a

MSF SPLIT FRACTIONS

Split Fraction	Boundary Condition
TT1	TTRIP function (ATWS - All DC power available)
TT2	TTRIP initiating event (ATWS)
TT3	TTRIP function - (ATWS-loss of bus D21 or D22)
TTF	Guaranteed failure of the TTRIP function
OS1	Isolation of faulted Steam Generator
OSF	Guaranteed failure of OS.
O31	RCS Depress and Cooldown (no AFS - all power)
O32	RCS Depress and Cooldown (no AFS-no power to 1 PORV)
O3F	Guaranteed failure of O3
O41	RCS Depress and Cooldown - all power available
O42	RCS Depress and Cooldown - no power to 1 PORV
O4F	Guaranteed failure of O4
O5E	RCS Depressurization Cooldown late HP=S,L1=S OS=F
O5A	RCS Depressurization Cooldown late HP=S,L1=S OS=S O4=F
O5B	RCS Depressurization Cooldown late HP=S L1=S OS=S O4=F (5A or 6A=F)
O5G	RCS Depressurization Cooldown late HP=F,L1=S OS=S O4=F
O5H	RCS Depressurization Cooldown late HP=F,L1=S OS=S O4=F (5A or 6A=F)
O52	RCS Depressurization Cooldown late HP=S L1=F O3=S
O53	RCS Depressurization Cooldown late HP=F L1=S OS=S
O5F	RCS Depressurization Cooldown and Makeup,late
SO1	Isolate SG late OS=F O5=S
SO2	Isolate SG late OS=S O4=F
SO3	Isolate SG late OS=F O5=F
SO4	Isolate SG late O3=S
SO5	Isolate SG late, given L1=F & HP=F
Y11	Core Cooling Recovery - All power available
Y1F	Guaranteed failure of Core Cooling Recovery
SG1	Operator S/G level control - loss of all AC/DC power
DP1	Depressurize vessel before failure
DPF	Guaranteed failure of DP
MU1	Failure to Make-Up from the RWST
MUF	Guaranteed failure of MU

TABLE 3.2-10b

MSF CAUSE TABLE

TT1 1 1.000E-02 Turbine trip function	
1.000E-02	AMSAC failure
2.501E-06	Solenoid valve failure
7.034E-08	Steam admission valve failures
1.758E-08	Single admission line (1 of 4)
TT2 0.000E+00 Turbine trip initiating event	
0.000E 00 Turbine trip initiating event	
TT3 Turbine trip x main steam line isolation	
1.157E-02	Turbine trip x main steam line isolation
1.565E-03	Turbine trip
7.034E-08	Main steam line isolation - independent
1.758E-08	Main steam line isolation - common cause
TTF Guaranteed failure of TT	
1.000E 00	Guaranteed failure of TT
OS1 Isolation of faulted SG	
1.987E-02	Isolation of faulted SG
1.749E-04	SRV Failure to open
4.576E-05	MS1 Failure to open
6.828E-04	AFW valves, failure to open
1.632E-03	AFW valves, failure on demand
5.690E-05	SGBD valve failure
OSF Guaranteed Failure of OS	
1.000E 00	Guaranteed Failure of OS

TABLE 3.2-10b

MSF CAUSE TABLE
(continued)

O31	RCS Depress and Cooldown (no AFS - all power)
1.126E-02	RCS Depress and Cooldown (no AFS - all power)
3.144E-04	RCS Depressurization failures
3.419E-05	RCS Depressurization hardware failures
2.802E-04	RCS Depressurization common cause failures
3.719E-03	S/G Hardware failure
3.719E-03	S/G Valve demand failure
7.222E-03	Operator Error
O32	RCS Depress and Cooldown (no AFS-no power to 1 PORV)
1.623E-02	RCS Depress and Cooldown (no AFS-no power to 1 PORV)
5.324E-03	Valve failures
3.744E-03	S/G Hardware Failures
3.744E-03	S/G Valve Demand Failures
7.162E-03	Operator Error
O3F	Guaranteed Failure
1.000E 00	Guaranteed Failure
O41	RCS Depressurization and Cooldown
1.501E-02	RCS Depressurization and Cooldown
3.055E-04	RCS Hardware and Common Cause Failures
3.422E-05	RCS Hardware Failure
2.713E-04	RCS Common Cause Failure
3.540E-03	Operator Error
1.117E-02	S/G Hardware
O42	RCS Depress and Cooldown - no power to 1 PORV
2.001E-02	RCS Depress and Cooldown - no power to 1 PORV
5.306E-03	RCS Depressurization
1.117E-02	S/G Hardware
3.596E-03	Operator Error

TABLE 3.2-10b

MSF CAUSE TABLE
(continued)

O4F	Guaranteed failure of O4
1.000E 00	Guaranteed failure of O4
O5E	RCS Depressurization/Cooldown and make up late
8.505E-03	RCS Depressurization/Cooldown and make up late
7.276E-03	RCS Depressurization
1.509E-07	Valve failures
1.509E-07	S/G Hardware
7.239E-03	Operator error
1.230E-03	Operator error
O5G	RCS DEP,C/D and makeup late given O41
1.147E-02	RCS DEP,C/D and makeup late
1.540E-02	RCS Depress and Cooldown - all power available
7.498E-01	RCS DEP,C/D and makeup late given O41
3.064E-04	RCS Depressurization
3.506E-05	Hardware Error
2.713E-04	Common Cause
1.187E-03	Operator error
3.865E-03	Operator error
O5H	RCS Depressuriz Cooldown late HP=F,L1=S,OS=S,O4=F (5A or 6A=F)
5.635E-01	RCS Depress Cooldown late HP=F,L1=S,OS=S,O4=F (5A or 6A=F)
1.157E-02	RCS Depressurization Cooldown late
1.998E-02	RCS Depressurization
5.268E-03	RCS Hardware Failure
5.268E-03	RCS valve failure
O5A	RCS Depressurization Cooldown Late HP=S,L1=S OS=S O4=F
4.729E-03	RCS Depressurization Cooldown Late HP=S,L1=S OS=S O4=F
7.310E-05	RCS Cooldown and Depressurization Late
1.540E-02	RCS Depressurization Late
3.064E-04	RCS Depressurization
3.506E-05	RCS Hardware Failure
2.713E-04	RCS Common Cause Valve Failure

TABLE 3.2-10b

MSF CAUSE TABLE
(continued)

O5B	Failure of O51 given failure of O42 - Power lost to 1 AC & DC bus.
4.149E-03	Failure of O51 given failure of O42 - Power lost to 1 AC & DC bus.
8.300E-05	RCS Cooldown and Depressurization Late
1.974E-02	RCS Depressurization Late
5.229E-03	RCS Valve failure
O52	RCS Depressurization Cooldown late HP=S L1=F O3=S
1.210E-03	RCS Depressurization Cooldown late HP=S L1=F O3=S
1.210E-03	Operator Error
O53	RCS Cooldown and Make-Up Late
5.774E-02	RCS Cooldown and Make-Up Late
6.756E-02	RCS Depressurization
1.105E-02	RCS Hardware Failure
5.651E-02	Operator Error
1.230E-03	Operator Error
O5F	Guaranteed failure of O5
1.000E 00	Guaranteed failure of O5
SO1	Isolate SG late given OS=F
1.224E-01	Isolate SG late given OS=F
1.013E-03	Isolate SG Late
2.011E-02	OS failure
2.570E-03	OS Hardware Failure
3.583E-03	OS Hardware Failures Late
1.754E-02	Operator Error
1.230E-03	Operator Error

TABLE 3.2-10b

MSF CAUSE TABLE
(continued)

SO2	Isolate SG late given OS=S but O4=F
3.545E-03	Isolate SG late given OS=S but O4=F
3.545E-03	OS Hardware Failures Late
SO3	Isolate SG late OS=F, O5=F
8.772E-03	Isolate SG late OS=F, O5=F
6.461E-07	Isolate SG Late
5.056E-04	Isolate SG Late
1.919E-03	Failure of S/G Isolation O3=S
2.189E-02	Failure of S/G Isolation
1.929E-02	Operator Error
1.715E-04	S/G PORV or Safety Valve Fails Open
4.587E-05	Fail to isolate main steam
5.743E-05	Failure of Blowdown Isolation Valves to Close
8.317E-03	RCS C/D - All power available
7.130E-03	Normal Secondary Side Cooldown
1.562E-07	Hardware S/G PORV'S
3.622E-05	Common Cause Failure
7.094E-03	Operator Error
7.094E-03	Operator Error
SO4	Failure of S/G Isolation late given O3=S
2.171E-03	Failure of S/G Isolation late given O3=S
1.749E-04	S/G PORV or Safety Valve Fails Open
4.576E-05	Fail to isolate main steam
6.828E-04	AFS Top Steam Supply MS-41 OR 42 Fails to Close
5.690E-05	Failure of Blowdown Isolation Valves to Close
1.210E-03	Failure of operator to isolate the failed S/G
SO5	Failure of S/G Isolation late given O3=S
1.053E-03	Failure of S/G Isolation late given O3=S
1.685E-04	S/G PORV or Safety Valve Fails Open
4.509E-05	Fail to isolate main steam
6.502E-04	AFS Top Steam Supply MS-41 OR 42 Fails to Close
5.876E-05	Failure of Blowdown Isolation Vlavles to Close
1.304E-04	Failure of operator to isolate the failed S/G

TABLE 3.2-10b

MSF CAUSE TABLE
(continued)

SOF	Guaranteed Failure of SO
1.000E 00	Guaranteed Failure of SO
Y11	Core Cooling Recovery
6.774E-02	Core Cooling Recovery
1.123E-02	Failure of 3 of 3 PORVs to open
5.651E-02	Operator Error
Y1F	Guaranteed failure
1.000E 00	Guaranteed failure
SG1	Failure to control S/G lvl given loss of all AC & DC Power
1.000E-01	Failure to control S/G lvl given loss of all AC & DC Power
SGF	Guaranteed Failure of SG
1.000E 00	Guaranteed Failure of SG

TABLE 3.2-10b

MSF CAUSE TABLE (continued)

MU1	RWST Make-Up from PWST
1.503E-03	RWST Make-Up from PWST
1.722E-04	Hardware - pumps
1.200E-04	Common Cause
1.210E-03	Operator Error
MUF	Guaranteed Failure of MU
1.000E 00	Guaranteed Failure of MU
DP1	RCS Depressurization before Vessel failure
1.529E-02	RCS Depressurization before Vessel failure
1.123E-02	Total- Core Coolin Recovery - All Power Available
4.055E-03	Operator Error
DPF	Guaranteed Failure of DP
1.000E+00	Guaranteed Failure of DP

TABLE 3.2-10(c)
MSF EQUATION FILE

TT1	1	TT1TOP= TT1_H1 + TT1_H2 + AMSAC	$ Turbine trip function (ATWS - All DC power available)
TT1	2	TT1_H1= IPVASD * IPV06D	$ Solenoid valve failure (20/AST and 20/ASB, auto-stops)
TT1	3	TT1_H2= 4 * LINE1	$ Steam admission valve failures
TT1	4	LINE1 = IPV07D * IPV07D	$ Single admission line (1 of 4) stop and control valves
TT2	1	TT2TOP= 0.0	$ Turbine trip initiating event (ATWS).
TT3	1	TT3TOP= TT3H1 + TT3H2 + AMSAC	$ TurbineTrip (ATWS - loss of DC Bus 21 or 22)
TT3	2	TT3H1 = IPVASD	$ Turbine trip
TT3	3	TT3H2 = 4 * LINE1	$ Main steam line isolation
TT3	4	LINE1 = IPV07D * IPV07D	$ Turbine Stop/Control Valve failure on demand
TTF	1	TTFTOP= 1.0	$ TT after RX trip fails or D21 * D22=F guarenteed failure
OS1	1	OS1TOP= SRV_SO+MS1_FO+AFW_FO+AFW_NI+ SG_BD + OS1_O	$ Isolation of a faulted Steam Generator
OS1	2	SRV_SO= SRV_SO	$ S/G PORV or Safety Valve Fails Open
OS1	3	MS1_FO= MS1_FO	$ Failure to isolate MS-1
OS1	4	AFW_FO= AFW_FO	$ AFS Top Steam Supply MS-41 OR 42 Fails to Close.
OS1	5	AFW_NI= AFW_NI	$ Failure to Isolate AFS Flow
OS1	6	SG_BD = SG_BD	$ Failure of Blowdown Isolation Vavles to Close
OS1	7	OST_O = IPOPIS	$ Failure of operator to isolatethe failed S/G.
OSF	1	OSF = 1.0	$ Guarenteed Failure of OS
O31	1	O31TOP= RCSDEP + SGENCD + O31_O	$ RCS depressurization and Cooldown (no AFS - all power available)
O31	2	RCSDEP= RCS_H + RCS_C	$ RCS Depressurization failures
O31	3	RCS_H = P455C * P456	$ RCS Depressurization hardware failures
O31	4	RCS_C = IPVB4D*IPV04D + IPVB5D*IPV10D	$ RCS Depressurization common cause failures
O31	5	SGENCD= SGEN_H	$ S/G Hardware failure
O31	6	SGEN_H= PV113X	$ S/G Valve demand failure
O31	7	O31_O = IPOPCE	$ Operator Error
O32	1	O32TOP= RCSDEP + SGENCD + O32_O	$ RCS Depressurization and Cooldown (no AFW - no power to 1 PORV)
O32	2	RCSDEP= P455C	$ Valve failures
O32	3	SGENCD= SGEN_H	$ S/G Hardware Failures
O32	4	SGEN_H= PV113X	$ S/G Valve Demand Failures
O32	5	O32_O = IPOPCE	$ Operator Error
O3F	1	O3F = 1.0	$ Guaranteed failure of O3
O41	1	O41TOP= RCSDEP + SG3_H + O41_O	$ RCS Depressurization and Cooldown - all power available
O41	2	RCSDEP= RCS_H + RCS_C	$ RCS Depressurization
O41	3	RCS_H = P455C * P456	$ Hardware Failure of both bleed paths
O41	4	RCS_C = IPVB4D * IPV04D + IPVB5D * IPV10D	$ Common Cause of the PORV's or Block Valves to Open.
O41	5	O41_O = IPOPCD	$ Operator Error
O41	6	SG3_H = SG3_H	$ Hardware
O42	1	O42TOP= RCSDEP + SG3_H + O42_O	$ RCS Depressurization and Cooldown - no power to one PORV
O42	2	RCSDEP= P455C	$ Hardware
O42	3	O42_O = IPOPCD	$ Operator error
O4F	1	O4F = 1.0	$ Gauareneteed failure of O4

TABLE 3.2-10(c)
MSF EQUATION FILE

```
05E    1 05OTOP= SGENCD                                          $ RCS Depressurzation and Cooldown late, HP=S, L1=S and OS=F
05E    2 SGENCD= SG1_H + SGEN_C + SGENOP                         $  Normal Secondary Side Cooldown
05E    3 SGEN_H= PV113X * PV113Y * PV113Z                        $  Hardware S/G PORV'S
05E    4 SG1_H = SG1_H                                           $  Hardware
05E    5 SGENOP= IPOPC1 + IPOPC2                                 $ Failure to initiate normal secondary cooldown (P2 + P3)
05A    1 05ATOP= 051041/041                                      $ RCS Depressurization and Cooldown Late HP=S,L1=S,OS=S,04=F
05A    2 051041= SG1_H+SGEN_C+ (SGENOP)*(041_O+SG3_H+RCSDEP )    $   RCS Cooldown and Depressurization Late
05A    3 041    = RCSDEP + SG3_H + 041_O                         $   RCS Depressurization Late
05A    4 RCSDEP= RCS_H + RCS_C                                   $    RCS Depressurization
05A    5 RCS_H = P455C * P456                                    $     RCS Hardware Failure
05A    6 RCS_C = IPVB4D * IPV04D + IPVB5D * IPV10D               $     RCS Common Cause Valve Failure
05A      SGENOP= IPOPC1                                          $
05B    1 05BTOP= 051042/042                                      $ RCS Depressurizaton Cooldown late, HP=S,L1=S,OS=S,04=F(5A OR 6A =F)
05B    2 051042= SG1_H + SGEN_C+(SGENOP)*(042_O+SG3_H+RCSDEP)    $   RCS Cooldown and Depressurization Late
05B    3 042    = RCSDEP + SG3_H + 042_O                         $   RCS Depressurization Late
05B    4 RCSDEP= P455C                                           $   RCS Valve failure
05B      SGENOP= IPOPC1                                          $
053    1 053TOP= SGENDP                                          $ RCS C/D & M/U Late
053    2 SGENDP= SG3_H + SGENOP                                  $  Failure to initiate rapid S/G Depressurization
053    3 SG3_H = SG3_H                                           $  Failure of 1 of 3 SG PORV's
053    4 SGENOP= IPOPC3                                          $  Failure of operator to initiate CCR
05G    1 05GTOP= 04105G/041                                      $ RCS Depressurization Cooldown late HP=F, L1=S, OS=S, 04=F
05G    2 04105G= SG3_H + (RCSDEP + 041_O) * (05G_OP)             $  Early and Late Cooldwn and Depressurization fail
05G    3 041    = SG3_H + RCSDEP + 041_O                         $  RCS Depress and Cooldown
05G    4 RCSDEP= RCS_H + RCS_C                                   $ RCS Depressurization
05G    5 RCS_H = P455C * P456                                    $  Hardware
05G    6 RCS_C = IPVB4D * IPV04D + IPVB5D * IPV10D               $  Common Cause
05G    8 041_O = IPOPCD                                          $  Operator Error
05G    9 05G_OP= IPOPC3                                          $  Operator Error
05H    1 05HTOP= 04205H/042                                      $ RCS Depressurization Cooldown late HP=F, L1=S, OS=S, 04=F (5A or 6A=F)
05H    2 04205H= SG3_H + (RCSDEP + 042_O) * (05H_OP)             $  Early and Late Cooldwn and Depres fail
05H    3 042    = SG3_H + RCSDEP + 042_O                         $ RCS Depress. & C/D, Power Lost to one AC and DC Bus
05H    4 RCSDEP= RCS_H                                           $  RCS Depressurizaton
05H    5 RCS_H = P455C                                           $  Hardware
05H    8 042_O = IPOPCD                                          $  Operator Error
05H    9 05H_OP= IPOPC3                                          $  Operator Error
053    1 053TOP= SGENDP                                          $ RCS C/D & M/U Late
053    2 SGENDP= SG3_H + SGENOP                                  $  Failure to initiate rapid S/G Depressurization
053    3 SG3_H = SG3_H                                           $  Failure of 1 of 3 SG PORV's
053    4 SGENOP= IPOPC3                                          $  Failure of the operator to initiate CCR
05F    1 05F    = 1.0                                            $ Guarenteed Failure of 05
S01    1 S01TOP= (OS1OSL) / (OS1)                                $ Isolate SG late given OS=F, 05=S
S01    2 OS1OSL= (OS1_H-AFW_NI) + (OS1_O+AFW_NI) * OSL_H+OS1_O * OSL_O$ Failure to isolate SG early and late
S01    3 OS1    = OS1_H + OST_O                                  $
S01    4 OS1_H = SRV_SO + MST_FO + AFW_FO + SG_BD + AFW_NI       $ SG isoltion hardware failure - early
S01    5 OSL_H = (IPVAC1 + IPV10D) * SV2                         $ SG safety valve opens and fails to close  after two phase flow)
S01    6 OS1_O = IPOPIS                                          $
S01    7 OSL_O = IPOPS1                                          $ Operator isolate SG late
S02    1 S02TOP= OSL_H                                           $ Isolated SG late  OS=S and 04=F
S02    2 OSL_H = (IPVAC1 + IPV10D) * SV2                         $ SG saftey valve opens and sticks open
S03    1 S03TOP= OS05OL/(OS1 * 05E)                              $ Isolate SG Late OS=F, 05=F
S03    2 OS05OL= (X1+ X2*OSL_H + X2*OSL_OM)*(X3 + 05E_OM) + Y    $ Isolate SG Late
S03      Y      =  X1*050S_O + X2* 050S_O*OSLC_O                 $ Isolate SG Late
```

TABLE 3.2-10(c)
MSF EQUATION FILE

```
SO3     3 X1     = OS1_H - AFW_NI                                   $ Isolation hardware short and long term
SO3     4 X2     = OS1_O + AFW_NI                                   $
SO3     5 X3     = SG1_H + SGEN_C                                   $
SO3     8 OS1_H = SRV_SO + MS1_FO + SG_BD + AFW_FO + AFW_NI         $ Failure of S/G Isolation - hardware
          OSL_H = (IPVAC1 + IPV10D) * SV2                           $ SG saftey valve opens and sticks open
SO3     9 OS1_  = SRV_SO+MS1_FO+AFW_FO+AFW_NI+ SG_BD + OS1_O        $ Failure of S/G Isolation.
SO3    10 OS1_O = IPOPIS                                            $  Operator error
SO3    11 SRV_SO= SRV_SO                                            $ S/G PORV or Safety Valve Fails Open.
SO3    12 MS1_FO= MS1_FO                                            $ Fail to isolate main steam
SO3    13 SG_BD = SG_BD                                             $ Failure of Blowdown Isolation Valves to Close
SO3    14 O5E    = SGENCD + O5E_O                                   $ RCS C/D  - All power available
SO3    15 SGENCD= SG1_H + SGEN_C                                    $  Normal Secondary Side Cooldown
SO3    16 SG1_H = SG1_H                                             $  Hardware S/G PORV'S
SO3    17 SGEN_C= IPVTOD * IPVB5D * IPVG5D                          $    Common Cause
SO3    18 O5E_O = IPOPC1 + IPOPC2                                   $    Operator fails to cooldown and Depressurize late (Cognative +
                                                                       Manipulative error)
SO3    19 OSLC_O= IPOPC3/IPOPC2                                     $ Conditional operator error to isolate ruptured SG given O5OS_O
SO3    20 O5OS_O= IPOPC2                                            $ Common cognitive error for SO AND O5
SO3    21 O5E_OM= IPOPC1                                            $ Operator fails to cooldown late - Manipulative error
SO3    22 OSL_OM= IPOPS1                                            $ Operator fails to isolate SG Late - Manipulative errors
SO4     1 SO4TOP= SRV_SO + MS1_FO + AFW_FO + SG_BD + SO4_O          $ Isolation SG late O3=S.
SO4     2 SRV_SO= SRV_SO                                            $ S/G PORV or Safety Valve Fails Open.
SO4     3 MS1_FO= MS1_FO                                            $ Fail to isolate main steam
SO4     4 AFW_FO= AFW_FO                                            $ AFS Top Steam Supply MS-41 OR 42 Fails to Close.
SO4     5 SG_BD = SG_BD                                             $ Failure of Blowdown Isolation Vlavles to Close
SO4     6 SO4_O = IPOPS1                                            $ Failure of operator to isolate the failed S/G.
SO5     1 SO5TOP= SRV_SO + MS1_FO + AFW_FO + SG_BD + SO5_O          $ Isolate SG late given L1=F and HP=F.
SO5     2 SRV_SO= SRV_SO                                            $ S/G PORV or Safety Valve Fails Open.
SO5     3 MS1_FO= MS1_FO                                            $ Fail to isolate main steam
SO5     4 AFW_FO= AFW_FO                                            $ AFS Top Steam Supply MS-41 OR 42 Fails to Close.
SO5     5 SG_BD = SG_BD                                             $ Failure of Blowdown Isolation Vlavles to Close
SO5     6 SO5_O = IPOPC4                                            $ Failure of operator to isolate the failed S/G.
SOF     1 SOF_  = 1.0                                               $  Guarenteed failure
DZ1     1 DZ1TOP= SG1_H + SGEN_C + DZ1_OP                           $ Post LOCA Cooldown and depressurization
DZ1     2 DZ1_OP= IPOPD3                                            $  Guarenteed failure
DZ2     1 DZ2TOP= (SG1_H + SGEN_C + DZ2_OP)* (1-NODZML) + NODZML    $ Post LOCA Cooldown following Medium LOCA
DZ2     2 DZ2_OP= IPOPD4                                            $   Operator error
DZF     1 DZFTOP= 1                                                 $ Post LOCA Cooldown Guaranteed Failure
Y11     1 Y11TOP= SG3_H + Y11_OP                                    $ Total- Core Cooling Recovery - All Power Available
Y11     2 SG3_H = SG3_H                                             $  Failure of 3 of 3 PORVs to open
Y11     3 Y11_OP= IPOPD1                                            $  Hardware failure
Y1F     1 Y1F_  = 1.0                                               $ Guarenteed failure of Core Cooling Recovery
SG1     1 SG1TOP= SG1_OP                                            $ Operator SG level control - loss of all AC/DC Power.
SG1     2 SG1_OP= HECSGL                                            $ Failure to control S/G lvl given loss of all AC & DC Power
SGF     1 SGF_  = 1.0                                               $ Guarenteed Failure of SG
DP1     1 DP1TOP= SG3_H + DP1_OP                                    $ Depressurize Vessel before failure
DP1     2 SG3_H = SG3_H                                             $  Total- Core Coolin Recovery - All Power Available
DP1     3 DP1_OP= IPOPD2                                            $   Operator Error
DPF     1 DPF_  = 1.0                                               $ Guaranteed failure of DP
```

TABLE 3.2-10(c)
MSF EQUATION FILE

```
MU1    1 MU1TOP= RWMU_H + RWMU_C + RWMUOP                         $  Failure to Make-Up from RWST
MU1    2 RWMU_H= PWPM1 * PWPM2                                    $ Hardware - pumps
MU1    3 RWMU_C= IPP13S * IPB13S + RWMUC1                         $   Common Cause - Pumps
MU1    4 RWMUOP= IPOPRW                                           $   FAilure of the operator to isolate RWST  make-up.
MUF    1 MUFTOP= 1.0                                              $ Guarenteed failure of MU
           AMSAC = .01                                            $ Failure rate of AMSAC from WCAP
           SRV_SO= PRV_FO + SV_SO                                 $ S/G PORV or Safety Valve Fails Open.
           PRV_FO= IPVAC1 * IPV13D                                $ S/G PORV Fails open and not isolated
           SV_SO = SVDEM * SVFO                                   $ Safety Valve demanded and fails open.
           SVDEM = IPV10D + IPV01T * T2 + IPVAC1                  $ ARV fails to open or sticks open and is therefore isolated
           SVFO  = IPVSV1                                         $ Safety valve opens and fails to close
           MS1_FO= MSIV * SDNR                                    $ Fail to isolate main steam
           SDNR  = SDIS + NRVS                                    $ Steam Dump or MS non return valves
           SDIS  = TSTOP + TBPASS + MSRHV + AEJV + MBFPV + GLSV   $ Failure to isolate main steam dump paths
           TSTOP = TT1_H1 + TT1_H2                                $ Turbine stop and control valves
           TT1_H1= IPVASD * IPV06D                                $ Solenoid valves
           TT1_H2= 4 * LINE1                                      $ Turbine stop and control valve fail to close
           LINE1 = IPV07D * IPV07D                                $ 1 OF 4 steam admission lines
           TBPASS= 12 * IPV07D * IPV13D                           $ Turbine by pass and manual isolation valves fail to close
           MSRHV = 4 * IPV04D                                     $ MOVS MS-6 thru MS-6-3 fail to close (can be operated manually)
           AEJV  = IPV13D                                         $ Air ejector stop valve MS-8 fails to close
           MBFPV = 2 * IPV13D                                     $ Main feedwater pump stop MS-7 AND MS-7-1
           GLSV  = IPV13D                                         $ Gland Seal Steam Valve MS-66
           MSIV  = (MSIV_F +  MSB)                                $ MSIV on Rupture SG fails to close
           MSIV_F= IPV08D + 2 * IPV06D * IPV06D                   $    Single MSIV (MSIV + 2 Supply AOV's)
           MSB   = 2 * IPV06D * IPV06D                            $     MSIV AOV'S - Common Cause
           NRVS  = 3 * IPV02D                                     $ MS non return valve on intact SGs fail to close on demand
           AFW_FO= IPV13D                                         $ AFS Top Steam Supply MS-41 OR 42 Fails to Close.
           AFW_NI= FV405X + FV405Y                                $ Failure to Isolate AFS Flow
           FV405X= IPV05D                                         $
           FV405Y= IPV05D                                         $
           SG_BD = IPV05D*IPV05D + IPV05D*IPVB5D                  $ Failure of blowdown isolation valves
           SGT_H = PV113X * PV113Y * PV113Z                       $
           SGEN_C= IPV10D * IPVB5D * IPVG5D                       $    Common Cause
           RWMU_H= PWPM1 * PWPM2                                  $
           SG3_H = PV113X + PV113Y + PV113Z                       $ Failure of 3 out of 3 sg PORV's
           RWMU_C= IPP13S * IPB13S + IPP13R * IPB13R * T1         $
           P455C = IPV10D + IPV04D                                $
           P456  = IPV10D + IPV04D                                $
           PV113X= IPV10D                                         $
           PV113Y= IPV10D                                         $
           PV113Z= IPV10D                                         $
           PWPM1 = IPP13S + IPPD13 * IPPF13 + IPP13R * T1         $ Pump1, Start, Run and Maintenance
           PWPM2 = IPP13S + IPPD13 * IPPF13 + IPP13R * T1         $ Pump1, Start, Run and Maintenance
           O41_O = IPOPCD                                         $
           O42_O = IPOPCD                                         $ Failure of AMSAC to initiate TT when given RT
           SV2   = 2E-1                                           $ SG Safety Valve fails to rese after passing two phase flow
           NODZML= 0.3                                            $ Fraction of MLOCA events which coolldown can't be successful
           HECSGL= 1E-1                                           $ Operator fails to use pnuematic level controllers correctly given SGTR
           T1    = 6.0                                            $
           T2    = 13140/2                                        $
```

TABLE 3.2-11a

RCS CAUSE TABLE

SPLIT FRACTION	DEFINITION
LS1	RCP Seal LOCA - no Seal LOCA, CCW successful
LS2	RCP Seal LOCA - Loss of bus 3A, 5A or 6A
LS3	RCP Seal LOCA - Loss of busses 5A, 3A, or 6A
LSF	RCP Seal LOCA - Guaranteed LOCA loss of 5A, 3A and 6A
PV1	PORV Sticks Open, isol. all pwr avail - loss of MFW I.E.
PV2	PORV Sticks Open, isol. 5A or 6A - loss of MFW I.E.
PV3	PORV Sticks Open, isol. 5A and 6A - loss of MFW I.E.
PV4	PORV Sticks Open, isol. all pwr avail - loss of Primary Flow I.E.
PV5	PORV Sticks Open, isol. 5A or 6A - loss of Primary Flow I.E.
PV6	PORV Sticks Open, isol. 5A and 6A - RCS lost Primary Flow I.E.
PV7	PORV Sticks Open, LOSP I.E.
BV1	Block valves closed - All power available
BV2	Block valves closed - lost 5A or 6A
BVF	Guaranteed failure of BV
PR2	ATWS pressure relief, All power available
PR3	ATWS pressure relief, loss of 5A, 6A, D21 or D22
PR4	ATWS pressure relief, (5A + D21) * (6A + D22)
PRF	Guaranteed failure of ATWS pressure relief
SR1	Secure ATWS pressure relief, all pwr available
SR2	Secure ATWS pressure relief, (5A or 6A lost)
SR3	Secure ATWS pressure relief, (5A and 6A lost)
PL1	Reactor Power >40% (ATWS)
TR1	Consequential SGTR given SLBIC Initiating Event
TR2	Consequential SGTR given Initiating Event is not SLBIC

TABLE 3.2-11b

RCS CAUSE TABLE

SPLIT FRACTION	DEFINITION
LS1	RCP Seal LOCA - No RCP seal LOCA, CCW Successful
0.000E+00	No RCP Seal LOCA - CCW Successful
LS2	RCP Seal LOCA, los of Bus 5A, 3A or 6A
5.527E-03	RCP Seal LOCA - loss of Bus 5A, 3A or 6A
1.627E-03	Hardware
3.900E-03	Operator Action
LS3	RCP Seal LOCA - Loss of buses 5A, 3A, or 6A, 5A or 3A, 6A
6.037E-02	RCP Seal LOCA - Loss of buses 3A, 5A, or 6A, 5A or 3A, 6A
1.242E-02	Hardware
4.405E-02	Maintenance
3.900E-03	Operator Error
LSF	Guaranteed Seal LOCA
1.000E 00	Guaranteed Seal LOCA
PV1	PORV sticks open - all power available - MFW lost
3.315E-06	PORV sticks open - all power available - MFW lost
PV2	PORV sticks open - 5A or 6A unavailable - MFW lost
3.041E-04	PORV sticks open - 5A or 6A unavailable - MFW lost

TABLE 3.2-11b

RCS CAUSE TABLE
(continued)

PV3	PORV Sticks open - 5A and 6A unavailable- MFW lost
6.048E-04	PORV Sticks open - 5A and 6A unavailable- MFW lost
PV4	PORV Sticks Open, all power available - RCS lost
8.288E-06	PORV Sticks Open, all power available - RCS lost
PV5	PORV Sticks Open, 5A or 6A unavailable - RCS lost
7.602E-04	PORV Sticks Open, 5A or 6A unavailable - RCS lost
PV6	PORV Sticks Open, isol. 5A and 6A unavailable - RCS lost
7.602E-04	PORV Sticks Open, isol. 5A and 6A unavailable - RCS lost
PV7	PORV Sticks Open, LOSP - RCS lost
6.048E-03	PORV Sticks Open, LOSP - RCS lost
BV1	Block valves closed - All power available
5.484E-03	Block valves closed - All power available
BV2	Block valves closed - lost 5A or 6A
5.027E-01	Block valves closed - lost 5A or 6A
BVF	Guaranteed Failure of BV
1.000E 00	Guaranteed Failure of BV

TABLE 3.2-11b

RCS CAUSE TABLE
(continued)

PR2 2.728E-02 ATWS pressure relief, All power available	
2.728E-02	ATWS pressure relief, All power available
1.274E-04	Hardware, no PORVs required
9.042E-04	Hardware, Safety valves
6.531E-02	Hardware and common cause, one PORV required
2.588E-04	Common Cause
1.791E-02	Hardware, both PORVS required
5.084E-01	Hardware
PR3 ATWS pressure relief,loss of 5A, 6A, D21 or D22	
7.184E-02	ATWS pressure relief,loss of 5A, 6A, D21 or D22
7.370E-04	Hardware, no PORVS required
8.946E-04	Hardware, Safety valves
3.588E-02	Hardware, one PORV required
2.546E-01	Hardware
3.522E-02	Hardware, both PORVS required
PR3 Hardware, guaranteed failure	
1.000E+00	Hardware, guaranteed failure
PR4 ATWS pressure relief, (5A + D21) * (6A + D22)	
1.769E-01	ATWS pressure relief, (5A + D21) * (6A + D22)
7.541E-04	Hardware, no PORVs required
9.153E-04	Hardware, Safety valves
1.409E-01	Hardware, one PORV required
1.000E+00	Hardware, guaranteed failure
3.522E-02	Hardware, both PORVS required
1.000E+00	Hardware, guaranteed failure
SR1 Secure presure relief ATWS, all pwr available	
1.305E-01	Secure presure relief ATWS, all pwr available
1.275E-01	Hardware
3.002E-03	Operator Error

TABLE 3.2-11b RCS CAUSE TABLE (continued)
SR2 Secure ATWS pressure relief (5A or 6A lost)
1.440E-01 Secure ATWS pressure relief (5A or 6A lost) 1.425E-01 Hardware 1.501E-03 Operator Error
SR3 Secure ATWS pressure relief (5A and 6A lost)
1.576E-01 Secure ATWS pressure relief (5A and 6A lost) 1.576E-01 Hardware
PL1 Reactor Power > 40% (ATWS)
6.620E-01 Reactor Power > 40% (ATWS)
TR1 Consequential SGTR given SLBIC Initiating Event
2.760E-02 Consequential SGTR given SLBIC Initiating Event
TR2 Consequential SGTR given Initiating Event is not SLBIC
0.000E 00 Consequential SGTR given Initiating Event is not SLBIC

TABLE 3.2-11(c)
RCS EQUATION FILE

```
LS1   1 LS1TOP= 0.00                                          $ RCP Seal LOCA, No RCP Seal LOCA, CCW successful
LS2   1 LS2TOP= LS2_H + LS2_O                                 $ RCP Seal LOCA - Loss of Bus 5A,3A or 6A
LS2   2 LS2_H = CWSPLY + CWMV                                 $  Citywater supply or Xties valves
LS2   3 LS2_O = IPOPLS                                        $  NPO aligns City Water to Charging Pumps
LS3   1 LS3TOP= LS3_H + LS3_O + LS3_M                         $ RCP Seal LOCA - Loss of buses 5A,3A or 5A,6A or 6A,3A
LS3   2 LS3_H = CPMP23 + L1T2C + CWMV                         $  Hardware
LS3   3 LS3_M = IPPD12 * IPPF12                               $  Maintenance
LS3   4 LS3_O = IPOPLS                                        $  Operator error
LSF   1 LSFTOP= 1.0                                           $ RCP Seal LOCA - Guarenteed LOCA - Loss of 3A, 5A and 6A
PV1   1 PV1TOP= PV455C * IPPRV1 + PV456 * IPPRV1              $ PORV sticks open - all power available - Loss of Main Feedwater (LOMFW) I.E.
PV2   1 PV2TOP= PO455C * IPPRV1 + PV456 * IPPRV1              $ PORV sticks open - 5A or 6A unavailable - LOMFW I.E
PV3   1 PV3TOP= PO455C * IPPRV1 + PO456 * IPPRV1              $ PORV Sticks open - 5A and 6A unavailable- LOMFW I.E.
PV4   1 PV4TOP= PV455C * IPPRV2 + PV456 * IPPRV2              $ PORV Sticks Open, all power available  - Loss of Primary Flow (LOPF) I.E.
PV5   1 PV5TOP= PO455C * IPPRV2 + PV456 * IPPRV2              $ PORV Sticks Open, 5A or 6A unavailable -- LOPF I.E.
PV6   1 PV6TOP= PO455C * IPPRV2 + PV456 * IPPRV2              $ PORV Sticks Open, isol. 5A and 6A unavailable -LOPF I.E.
PV7   1 PV7TOP= PO455C * IPPRV3 + PO456 * IPPRV3              $ PORV Sticks Open, LOSP I.E.
BV1   1 BV1TOP= .5 * MOV535 + .5 * MOV536                     $  Block valves closed - All power available
BV2   1 BV2TOP= .5 + .5 * MOV536                              $  Block valves closed - lost 5A or 6A
BVF   1 BVFTOP= 1.0                                           $ Guarenteed Failure of BV
PR2   1 PR2TOP= PR2A + PR2B + PR2C                            $  ATWS pressure relief, All power available
PR2   2 PR2A  = PR2A_H * UETPVO                               $   Hardware, 0 PORVS Required
PR2   3 PR2A_H= 3 * TPV03D                                    $   Hardware, Safety Valves
PR2   4 PR2B  = (PR2B_H + PR2B_C) * UETPV1                    $   Common Cause, 1 PORV Required
PR2   5 PR2B_H= 3 * IPV03D + (TPV10D + BVFC) * (IPV10D + BVFC) $  Hardware
PR2   6 PR2B_C= IPV10D * IPVBOD                               $   Common Cause
PR2   7 PR2C  = PR2C_H * UETPV2                               $ Hardware and both PORVs required
PR2   8 PR2C_H= 3 * TPV03D + 2 * (IPV10D + BVFC)              $  Hardware
PR3   1 PR3TOP= PR3A + PR3B + PR3C                            $ ATWS Pressure Relief, loss of 5A, 6A D21 or D22
PR3   2 PR3A  = PR3A_H * UETPVO                               $  Hardware, 0 PORVs Required
PR3   3 PR3A_H= 3 * TPV03D                                    $    Hardware
PR3   4 PR3B  = PR3B_H * UETPV1                               $  Hardware and 1 PORVs required
PR3   5 PR3B_H= 3 * TPV03D + IPV10D + BVFC                    $    Hardware
PR3   6 PR3C  = UETPV2 * PR3C_H                               $  Hardware and both PORV's Required
PR3   7 PR3C_H= 1.0                                           $    Hardware
PR4   1 PR4TOP= PR4A + PR4B + PR4C                            $ ATWS pressure relief(5A + D21) * (6A + D22)
PR4   2 PR4A  = PR4_H * UETPVO                                $  Hardware and 0 PORVs Required
PR4   3 PR4_H = 3 * IPV03D                                    $     Hardware, safety valves
PR4   4 PR4B  = PR4B_H * UETPV1                               $  Hardware and 1 PORV required
PR4   5 PR4B_H= 1.0                                           $     Hardware, guarenteed failure
PR4   6 PR4C  = PR4C_H * UETPV2                               $  Hardware and both PORVs required
PR4   7 PR4C_H= 1.0                                           $     Hardware, guarenteed failure
PRF   1 PRFTOP= 1.0                                           $ Guarenteed failure of PR
```

TABLE 3.2-11(c)
RCS EQUATION FILE

```
SR1    1 SR1TOP= SR1_H + SR1_OP                              $  Secure presure relief ATWS, all pwr available
SR1    2 SR1_H = 3 * IPV03C + 2 * IPV10C * IPV04D            $    Hardware
SR1    3 SR1_OP= 2 * IPV10C * IPOPB4                         $    Operator Error
SR2    1 SR2TOP= SR2_H + SR2_OP                              $ Secure ATWS pressure relief (5A or 6A lost)
SR2    2 SR2_H = 3 * IPV03C + IPV10C + IPV10C * IPV04D       $   Hardware
SR2    3 SR2_OP= IPV10C * IPOPB4                             $   Operator error
SR3    1 SR3TOP= SR3_H                                       $ Secure ATWS pressure relief (5A and 6A lost)
SR3    2 SR3_H = 3 * IPV03C + 2 * IPV10C                     $   Hardware
PL1    1 PL1TOP= 0.662                                       $  Plant Power > 40% (ATWS)
TR1    1 TR1TOP= 2.76E-2                                     $ Consequential SGTR given INIT =  SLBIC
TR2    1 TR2TOP= 0.0                                         $ Consequential SGTR given INIT = -SLBIC
         PV455C= IPV10C * (IPV04D + IPOPB1)                  $
         PV456 = IPV10C * (IPV04D + IPOPB1)                  $
         PO455C= IPV10C                                      $
         PO456 = IPV10C                                      $
         MOV535= IPV04D + IPOPB3                             $
         MOV536= IPV04D + IPOPB3                             $
         IPPRV1= .02                                         $
         IPPRV2= .05                                         $
         IPPRV3= .2                                          $
         CWSPLY= 0.0                                         $
         CPMP23= IPP12R * T1 + IPP12S                        $
         CWMV  = 2 * IPV05D                                  $
         L112C = IPV05D                                      $
         BVFC  = .25                                         $
         UETPV0= 1 - (UETPV1 + UETPV2)                       $
         UETPV1= 72/365 * .5/C                               $
         UETPV2= 18/365  * .5/C                              $
         C     = .7                                          $
         T1    = 6                                           $
```

TABLE 3.2-12a

RPS SPLIT FRACTIONS

Split Fraction	Definition
RT1	Reactor trip function within 1 min - LOCA or transients.
RT2	Reactor trip function within 1 min - rods only (LOSP).
RT3	Reactor trip function - Reactor Trip Initiating Event
RTF	Guaranteed failure of reactor protection.
BR1	Emergency Boration within 10 min given RT, All power Available
BR2	Emergency Boration within 10 min given RT, loss of power to one bus
BRF	Emergency Boration within 10 min - guaranteed failure
MD1	Rx trip by operator within 10 mins given RT=F,
MD2	Rx trip by operator within 10 mins given RT&EB=F, All power available
MD3	Rx trip by operator within 10 mins given RT&EB=F, Loss of power to 1 bus

TABLE 3.2-12b RPS CAUSE TABLE
RT1 3.664E-06 RT1 - Total - including operator action.
3.664E-06 RT1 - Total - including operator action. 8.189E-05 Auto initiation of reactor trip 1.911E-04 Both RT breakers fail to close - random plus CCF 1.103E-07 RCCA - Failure of 2 or more rod assy's to insert 1.559E-03 Train A fails(including RT bkr) xTrain B fails (excluding RT bkr) 2.932E-06 RTA - Reactor trip breaker A fail on demand 2.722E-03 Logic trip relay or matrix failures 3.900E-03 Operator failure to initiate RT in 1 min
RT2 RT function - rods only (LOSP)
2.382E-06 RT function - rods only (LOSP)
RT3 RT function - reactor trip initiating events
0.000E 00 RT function - reactor trip initiating events
RTF Guaranteed failure of the RT function
1.000E 00 Guaranteed failure of the RT function
BR1 Emergency Boration fail, given all power available
7.594E-02 Emergency Boration fail, given all power available
BR2 Emergency Boration fail, given loss of bus 3A
6.815E-02 Emergency Boration fail, given loss of bus 3A
BRF Emergency Boration- Guaranteed Failure
1.000E 00 Emergency Boration- Guaranteed Failure
MD1 Reactor trip by operator within 10 minute given RT=F
1.104E-01 Reactor trip by operator within 10 minute given RT=F
MD2 Reactor trip by operator within 10 min given RT & EB=F, all power available
5.455E-01 Reactor trip by operator within 10 min given RT & EB=F, all power avail
MD3 Reactor trip by operator within 10 min given RT & EB=F, loss of bus 3A
6.159E-01 Reactor trip by operator within 10 min given RT & EB=F, loss of bus 3A

TABLE 3.2-12(c)
RPS EQUATION FILE

```
RT1     1 RT1TOP= RCCA+OPA1*(RPS1+RPS2)+RPS2*MG1             $ Reactor Trip Function within 1 min - LOCA or transeients.
RT1     2 RPS1   = TEST + DOUBL + MISCAL                     $ Auto initiation of trip breakers
RT1     3 RPS2   = BTB + CC                                  $ Rx trip bkr -random plus CCF
RT1     3 RCCA   = (52 * 51/2) * IPROD1 * IPROD1             $ RCCA >2 rod assy's Fail to insert
RT1     9 RTB    = IPRPBD                                    $     RTA - Rx Trip breaker A
RT1    10 BTB    = IPRPBD * IPRPBD                           $ Both RT breakers
RT1    12 WIR    = WP + WG                                   $    Wiring failures - Total
RT1    13 OPA1   = IPOPA1                                    $    Operator error
RT2     1 RT2TOP= (52 * 51 / 2) * IPROD1 * IPROD1            $ Reactor Trip (RT) function within 1 min - rods only (LOSP)
RT3     1 RT3TOP= 0.00                                       $ Reactor Trip function - Reactor Trip Initiating Event
RTF     1 RTFTOP= 1.00                                       $ Guarenteed failure of Reactor protection
BR1     1 EB1TOP= RT1EB1/RT1                                 $  Emergency Boration within 10 min given RT, all power available
BR2     1 EB2TOP= RT1EB2/RT1                                 $  Emergency Boration within 10 min given RT, loss of power to one bus
BRF     1 EBFTOP= 1.0                                        $  Emergency Boration within 10 min - guarenteed failure.
MD1     1 MD1    = RT1MD1/RT1                                $ RT by operator within 10 mins given RT=F.
MD1     2 RT1MD1= RCCA+(RPS2+RPS1)*OPA10+RT1MDA              $
MD1       RT1MDA= OPA10L * RPS2 * MG1                        $
MD1     3 OPA10 = IPOPA2                                     $   Operator error
MD1     4 OPA10L= IPOPA3                                     $   Operator error
MD2     1 MD2TOP= RTEBM1/RT1EB1                              $ RT by operator within 10 mins given RT&EB=F, all power available
MD3     1 MD3TOP= RTEBM2/RT1EB2                              $ RT by operator within 10 mins given RT&EB=F, Loss of power to 1 bus
          RT2    = (52*51/2)*IPROD1*IPROD1                   $ RTrip Prot Func rods only (LOSP).
          RTEBM1= (RCCA+RPS2*MG1)*Z2 +RTEBMA                 $
          Z2     = (OPA10+OPA10L*EBH1)                       $
          RTEBM2= (RCCA+RPS2*MG1)*Z3+RTEBMA                  $
          Z3     = (OPA10+OPA10L*EBH2)                       $
          RTEBMA= OPA10L*(RPS2+RPS1)*EBH2+RTEBMC             $
          RTEBMC= OPA10 * (RPS1 + RPS2)                      $
          RT1EB1= (RCCA+RPS2*MG1)*Z4+RT1EBA                  $
          Z4     = (OPA10+EBH1)+RT1EBA                       $ RT1 & Emer Boro Fail
          RT1EBA= OPA1*(RPS2+RPS1)*EBH1+Z5                   $
          Z5     = OPA10*(RPS1+RPS2)                         $
          EBH1   = CP1+BAT1                                  $ C/P & BATP = F
          CP1    = CP_H1+CP_M1+CP_C1+CP_T1+CP_O1             $ LOSP All Bus Avail
          CP_H1  = CPR*CPS*CPS+FLTR+Z6                       $
          Z6     = RCPR+SUPLY1+CTYWTR                        $   Hardware Contibution
          CP_M1  = 2 * ((5 * MNTUNS + MNTUNL)/6)             $   Maintenance Contribution
          CP_C1  = CPFTSB + CPFTRG                           $   Common Cause Contribution
          CP_T1  = 0.0                                       $   Operator Action Contribution
          CP_O1  = 0.0                                       $   Testing Contribution
          BAT1   = BA_H1 + BA_M1 + BA_C1                     $
          BA_H1  = BATPS * BATPS + MOV333                    $
          BA_M1  = BATPM * (BATPS + BATPM)*2                 $
          BA_C1  = BAP_CS + BAP_CR                           $
          BAP_CS= IPPT4S * IPBT4S                            $
          BAP_CR= IPP14R * IPB14R*MT                         $
          RT1EB2= (RCCA+RPS2*MG1)*Z7+RT1EBB                  $
          Z7     = (OPA10+EBH2)+RT1EBB                       $
          RT1EBB= OPA1*(RPS2+RPS1)*EBH2+Z8                   $
          Z8     = OPA10*(RPS1+RPS2)                         $
```

TABLE 3.2-12(c)
RPS EQUATION FILE

```
  EBH2  = CP2 + BAT2                                  $
  BAT2  = BA_H2 + BA_M2                               $
  BA_H2 = BATPS                                       $
  BA_M2 = BATPM                                       $
  BATPM = IPPD14*IPPF14                               $
  BATPS = IPP14S                                      $
CP2    = CP_H2+CP_M2+CP_C2+CP_CT+CP_CO                $ LOSP/No SI, loss of bus 5A
CP_H2 = CPR*CPS+FLTR+RCPR+SUPLY2+CTYWTR               $
CP_M2 = MNTUNS                                        $     One Standby Pump  Maintenance
CP_C2 = IPB12R * IPP12R                               $
CP_CT = 0.0                                           $
CP_CO = 0.0                                           $
RTT    = RCCA+OPA1*(RPS1+RPS2)+RPS2*MG1               $ RT1 - Total - inc Operator Action s
RPS1   = TEST +  MISCAL  + DOUBL                      $ AUTO initiation of trip breakers
RPS2   = RTB + CC                                     $ Rx Trip Bkr -random plus common cause
DOUBL = RPA + RPB                                     $   2 Trn Fail  exclud fail of RT bkr
MISCAL= IPRPIC*IPRPIC                                 $   Miscalibration error
CC     = IPBRPD * IPRPBD                              $   Common cause failures
RCCA   = (52*51/2)*IPROD1*IPROD1                      $    RCCA - Fail >2 rod assy's to insert
TEST   = (IPMDRT/TI)*WG*2                             $   Test failures
RTA    = IPRPBD                                       $      RTA - Rx Trip bkr A fail on demand
RTB    = IPRPBD*IPRPBD                                $ Both RT breakers fail to open
WIR    = WP+WG                                        $    Wiring failures - Total
WP     = IPCCLL*360                                   $     Wiring shorts to power failures
WG     = IPCCL2*9                                     $     Wiring shorts to ground failures
OPA1   = IPHERA                                       $  Operator Action trip RPS/de-energize MG in     1 min
CPR    = (2*IPV01T+IPP12R)*MT                         $    Restarted C/P component failure
CPS    = 2 * IPV01T*MT+IPV02D+IPP01S                  $    Started C/P
FLTR   = IPFLTS * MT                                  $
RCPR   = 3 * IPV01T * MT + 2 * IPV02D                 $    RCP Hardware failure (just charging)
RCPR3 = IPV01T * MT + 2 * IPV02D                      $          SI MOV's have lost power
SUPLY1= IPV05D + 3 * IPV01T * MT + IPV02D             $    Normal and Emergency Supply Sources
SUPLY2= IPV05D + 2 * IPV02D                           $
CPFTR = IPP12R * MT                                   $      C/P Fails to run for the MT
MNTUNS= FREQS * DURS                                  $    Short Duration Maintenance Unavailability
MNTUNL= FREQL * DURL                                  $    Long Duration Maintenance Unavailability
FREQL = IPPF12                                        $
DURL  = IPPD12                                        $
FREQS = ILPF12                                        $
DURS  = ILPD12                                        $
CPFTRG= .5 * BETAR * (1-GAMMAR) * IPP12R +Z1          $
Z1     = BETAR*GAMMAR*IPP12R                          $   CCF of all C/PS to run
CPFTSB= BETAS * IPP01S                                $   CCF of two S/B C/P to start
BETAS = IPB12S                                        $
BETAR = IPB12R                                        $
GAMMAR= IPG12R                                        $
CTYWTR= CW_H + CW_O                                   $  City Water Supply to the C/P
CW_H  = CTYSUP + VALVES                               $  City Water unavailability + Valve unavailability
```

TABLE 3.2-12(c)
RPS EQUATION FILE

```
CTYSUP= 0.0                                   $  City Water Supply unavailability
VALVES= 5 * IPV13D + 5 * IPV01T * MT          $
RPB   = RPA                                   $
RPA   = (RTB+LOGIC+WP+WG)*(LOGIC+WP+WG)       $    RTA train A failure
WP    = IPCCLL * 360                          $     Wiring shorts to power failures
WG    = IPCCL2 * 9                            $     Wiring shorts to ground failures
LOGIC = (IPTR1D * IPTR1D) * 2                 $     Logic trip relay or matrix failures
RTB   = IPRPBD                                $     RTA - Reactor trip breaker A fail on demand
CW_O  = HEC1                                  $
MT    = 2.4E1                                 $  Mission Time
OPA1  = IPOPA1                                $ Operator fails to initiate RT within 1 min
OPA10L= IPOPA3                                $ Operator fails to deenergize MG sets locally within 10 mins
OPA10 = IPOPA2                                $
MOV333= IPV04D                                $
MG1   = 2 * IPBKRO                            $
TI    = 2160                                  $  Logic channel test interval
```

TABLE 3.2-13a

RSS SPLIT FRACTIONS

Split Fraction	Boundary Condition
HR1	High head recirculation (HHR), Medium LOCA - all power available
HR2	HHR, MLOCA - loss of power to bus 5A
HR3	HHR, MLOCA - loss of power to bus 6A
HR4	HHR, MLOCA - loss of power to bus 3A
HR6	HHR, MLOCA - loss of CCW system (SI pumps work)
HR7	HHR, MLOCA - loss of power to buses 5A and 3A
HR8	HHR, MLOCA - loss of power to buses 6A and 3A
HRA	High head recirculation (HHR), Small LOCA - all power available
HRB	HHR, SLOCA - loss of power to bus 5A
HRC	HHR, SLOCA - loss of power to bus 6A
HRD	HHR, SLOCA - loss of power to bus 3A
HRG	HHR, SLOCA - loss of CCW system (SI pumps work)
HRH	HHR, SLOCA - loss of power to buses 5A and 3A
HRI	HHR, SLOCA - loss of power to Buses 6A and 3A
HRF	Guaranteed failure of HHR
LR1	Low head recirculation (LHR) - all power available
LR2	LHR - bus 5A or 6A lost
LR3	LHR - bus 3A lost
LRA	LHR - CCW lost; all power available
LRB	LHR - CCW and BUS 3A lost
LRF	Guaranteed failure of LHR
LR4	RHR Shutdown Cooling Mode, All power available
LR5	RHR Shutdown Cooling Mode, Loss of bus 3A
RH1	Recirculation Heat Removal, All power avaiable
RH2	Recirculation Heat Removal, Loss of bus 5A or 6A
RHF	Guaranteed Failure of RH
RC1	Hot leg recirculation (HLR) - all power available
RC2	HLR - bus 5A or 6A lost
RC3	HLR - bus 3A lost
RCF	Guaranteed failure of HLR

TABLE 3.2-13b

RSS CAUSE TABLE

HR1	High Head Recirculation, MLOCA - All power available
7.416E-03	HHR, Medium LOCA - All power available
4.171E-05	Hardware failure
2.814E-06	SI pump section
3.876E-05	LP pump section
2.193E-07	Maintenance
7.806E-08	RHR Pump Maintenance
1.412E-07	Auxiliary CCW Pump Maintenance
0.000E 00	Heat exchanger Maintenance
0.000E 00	Recirculation Pump Maintenance
7.323E-03	Operator Error
5.216E-05	Common cause failure
1.146E-06	RHR pump common cause
1.839E-05	Recirculation pump common cause
1.726E-05	Auxiliary CCW pump common cause
2.157E-02	Total RHR (includes operator action)
6.668E-03	RHR pump section
1.532E-03	Recirculation pump section
1.071E-07	Heat exchangers
HR2	High Head Recirculation, MLOCA - Loss of power to bus 5A
3.340E-02	HHR, Medium LOCA - Loss of power to bus 5A
2.596E-02	Hardware failure
1.580E-03	LP to SI pump crosstie
2.438E-02	Recirculation pump section
3.092E-04	Maintenance
3.092E-04	Auxiliary CCW pump maintenance
7.323E-03	Operator Error
0.000E 00	SI pump common cause

TABLE 3.2-13b

RSS CAUSE TABLE

HR3	**High Head Recirculation, MLOCA - Loss of power to bus 6A**
3.340E-02	HHR - loss of power to bus 6A
2.596E-02	Hardware failure
1.580E-03	LP To SI pump crosstie
2.438E-02	LP pump section
3.092E-04	Maintenance
3.092E-04	Auxiliary CCW pump maintenance
7.323E-03	Operator Error
HR4	**High Head Recirculation - MLOCA, Loss of power to bus 3A**
7.446E-03	HHR - loss of power at bus 3A
5.238E-05	Hardware failure
2.773E-06	LP to SI pump crosstie
4.945E-05	LP pump section
3.188E-06	Maintenance
2.972E-06	RHR pump maintenance
2.168E-07	Auxiliary CCW pump maintenance
7.323E-03	Operator Error
6.824E-05	Common cause failure
2.728E-05	Recirc. pump common cause
2.549E-05	Auxiliary CCW pump common cause
3.176E-02	Total RHR (includes operator action)
1.702E-02	RHR pump section
1.561E-03	Recirculation pump section
1.160E-07	Heat exchangers
HR6	**High Head Recirculation - MLOCA, Loss of CCW**
2.907E-02	HHR - loss of the CCW system
2.105E-02	Hardware failure
2.800E-06	LP to SI pump crosstie
2.105E-02	LP pump section
4.554E-05	Maintenance
4.554E-05	RHR pump maintenance
7.323E-03	Operator Error
8.114E-04	Common cause failure
7.961E-04	RHR pump common cause

TABLE 3.2-13b

RSS CAUSE TABLE

HR7 High Head Recirculation - MLOCA, Loss of power to buses 5A and 3A	
2.685E-02	HHR - MLOCA, Loss of power to buses 5A and 3A
2.609E-02	Hardware failure
1.587E-03	LP to SI pump crosstie
2.451E-02	Recirculation pump section
3.734E-04	Maintenance
3.734E-04	Auxiliary CCW pump maintenance
3.916E-04	Operator Error
0.000E 00	Common cause failure
HR8 High Head Recirculation - MLOCA, Loss of power to buses 6A and 3A	
3.340E-02	HHR - MLOCA -loss of power to buses 6A and 3A
2.596E-02	Hardware failure
1.580E-03	LP to SI crosstie
2.438E-02	LP pump section
3.092E-04	Maintenance
3.092E-04	Auxiliary CCW pump maintenance
7.323E-03	Operator Error
0.000E 00	Common cause failure

TABLE 3.2-13b

RSS CAUSE TABLE

HRA	High Head Recirculation, SLOCA - All power available
7.334E-04	High Head Recirculation, SLOCA - all power available
3.850E-05	Hardware failure
2.805E-06	SI pump section
3.557E-05	LP pump section
2.168E-07	Maintenance
7.519E-08	RHR pump maintenance
1.416E-07	Auxiliary CCW pump maintenance
0.000E 00	Heat exchanger maintenance
0.000E 00	Recirc. pump maintenance
6.430E-04	Operator Error
5.177E-05	Common cause failure
1.380E-06	RHR pump common cause
1.802E-05	Recirc. pump common cause
1.689E-05	Auxiliary CCW pump common cause
2.136E-02	Total RHR (includes operator action)
6.457E-03	RHR pump section
1.650E-03	Recirculation pump section
1.125E-07	Heat exchangers
HRB	High Head Recirculation - SLOCA, Loss of power to bus 5A
2.696E-02	HHR, Small LOCA - Loss of power to bus 5A
2.603E-02	Hardware failure
1.582E-03	LP to SI pum crosstie
2.445E-02	Recirculation pump section
3.053E-04	Maintenance
3.053E-04	Auxiliary CCW pump maintenance
6.430E-04	Operator Error
0.000E 00	SI pump common cause
HRC	High Head Recirculation - SLOCA, Loss of power to bus 6A
2.696E-02	HHR, SLOCA - loss of power to bus 6A
2.603E-02	Hardware failure
1.582E-03	LP To SI pump crosstie
2.445E-02	LP pump section
3.053E-04	Maintenance
3.053E-04	Auxiliary CCW pump maintenance
6.430E-04	Operator Error

TABLE 3.2-13b

RSS CAUSE TABLE

HRD	High Head Recirculation - SLOCA, Loss of power to bus 3A
7.681E-04	HHR, SLOCA - loss of power at bus 3A
5.294E-05	Hardware failure
2.827E-06	LP to SI pump crosstie
4.997E-05	LP pump section
3.691E-06	Maintenance
3.474E-06	RHR pump maintenance
2.172E-07	Auxiliary CCW pump maintenance
6.430E-04	Operator Error
6.851E-05	Common cause failure
2.761E-05	Recirc. pump common cause
2.554E-05	Auxiliary CCW pump common cause
3.196E-02	Total RHR (includes operator action)
1.721E-02	RHR pump section
1.567E-03	Recirculation pump section
1.149E-07	Heat exchangers
HRG	High Head Recirculation, SLOCA - Loss of CCW
2.308E-02	HHR - loss of the CCW system (assumed city water)
2.126E-02	Hardware failure
2.770E-06	LP to SI pump crosstie
2.126E-02	LP pump section
4.567E-05	Maintenance
4.567E-05	RHR pump maintenance
6.430E-04	Operator Error
8.031E-04	Common cause failure
7.879E-04	RHR pump common cause
HRH	High Head Recirculation, SLOCA - Loss of power to buses 5A and 3A
2.685E-02	HHR, SLOCA - Loss of power to bus 5A and 3A
2.603E-02	Hardware failure
1.582E-03	LP to SI pump crosstie
2.445E-02	Recirculation pump section
3.053E-04	Maintenance
3.053E-04	Auxiliary CCW pump maintenance
6.430E-04	Operator Error
0.000E 00	Common cause failure

TABLE 3.2-13b

RSS CAUSE TABLE

HRH	High Head Recirculation, SLOCA - Loss of power to buses 6A and 3A
2.676E-02	HHR, SLOCA -loss of power to bus 6A and 3A
2.583E-02	Hardware failure
1.604E-03	LP to SI crosstie
2.422E-02	LP pump section
3.080E-04	Maintenance
3.080E-04	Auxiliary CCW pump maintenance
6.430E-04	Operator Error
HRF	High Head Recirculation - Guaranteed Failure
1.000E 00	HHR - Guaranteed failure
LR1	Low Head Recirculation - All power available
9.343E-03	LHR- All power available
4.103E-04	Hardware
1.779E-06	Maintenance
5.838E-08	Single RHR pump maintenance
1.721E-06	Auxiliary CCW pump maintenance
8.500E-03	Operator error
4.378E-04	Common cause contribution
8.621E-07	RHR pump common cause
2.259E-04	Recirc. pump common cause
2.111E-04	Auxiliary CCW pump common cause
2.408E-05	Heat exchanger valve common cause
2.649E-01	Operator error - shift to RHR pumps
6.668E-03	RHR pump path
1.532E-03	Internal recirculation pump flow path
8.208E-08	Heat exchanger paths
2.249E-08	Injection paths

TABLE 3.2-13b RSS CAUSE TABLE	
LR2	Low Head Recirculation - loss of power to bus 5A or 6A
3.298E-02	LHR - loss of power to bus 5A or 6A
2.438E-02	Hardware
3.092E-04	Auxiliary CCW pump maintenance
8.500E-03	Operator error
0.000E+00	Common cause
2.424E-02	Internal recirculation pump flow path
3.722E-05	Heat exchanger path
2.314E-08	Injection paths
LR3	Low Head Recirculation - loss of power to bus 3A
4.319E-02	LHR - loss of power to bus 3A
4.343E-04	Hardware
1.582E-03	Maintenance
1.580E-03	RHR pump maintenance
1.361E-06	Auxiliary CCW pump maintenance
4.054E-02	Operator error
7.503E-04	Common cause contribution
3.666E-04	Recirc. pump common cause
3.599E-04	Auxiliary CCW pump common cause
2.380E-05	Heat exchanger valve common cause
2.783E-01	Operator error - shift to RHR pumps
2.311E-02	RHR pump path
1.606E-03	Internal recirculation pump flow path
1.141E-05	Heat exchanger paths
5.837E-07	Injection paths
LRA	Low Head Recirculation - Loss of CCW, all power available
2.759E-01	LHR - loss of CCW, all power available
LRB	Low Head Recirculation - Loss of CCW, loss of power to Bus 3A
2.767E-01	LHR - Loss of CCW, loss of power to bus 3A

TABLE 3.2-13b

RSS CAUSE TABLE

LRF	Low Head Recirculation - Guaranteed Failure
1.000E 00	LPR - Guaranteed failure
LR4	RHR Shutdown Cooling - All Power Available
5.842E-03	RHR Shutdown Cooling - All power available
4.981E-03	Hardware total
4.975E-03	Hardware, pumps/suction path/HX discharge
3.202E-03	Hot leg suction
3.340E-03	HX 21 Path
1.636E-03	HX 22 Path
2.250E-08	Injection Path
4.644E-05	RHR Maintenance
8.148E-04	Common Cause
7.994E-04	Common Cause - Pumps
1.541E-05	Common Cause - Valves
LR5	RHR Shutdown Cooling - loss of power to one bus
1.785E-02	RHR Cooling - loss of power to one bus
RH1	Recirculation Cooling Capability - All power available.
3.346E-05	Recirculation cooling - All power available.
1.818E-05	Hardware total
9.089E-06	Hardware, valves
1.528E-05	Common Cause
RH2	Recirculation Cooling Capability - Loss of power to one Bus
3.779E-03	Recirculation Cooling - Loss of power to one bus
3.779E-03	Hardware
RHF	Guaranteed Failure of Recirculation Cooling
1.000E 00	Guaranteed Failure of Recirculation Cooling

TABLE 3.2-13b

RSS CAUSE TABLE
(continued)

RC1	**Hot Leg Recirculation - All Power Available**
6.804E-04	Hot leg recirculation - all power available
1.314E-04	Hardware failures
6.005E-06	Maintenance
2.980E-06	SIS Pump-21 maintenance
4.550E-08	SIS Pump-22 maintenance
2.980E-06	SIS Pump-23 maintenance
5.430E-04	Common cause failures
RC2	**Hot Leg Recirculation - Power lost to bus 5A or 6A**
1.414E-02	HLR - bus 5A (or 6A) lost
1.385E-02	Hardware failures
2.879E-04	Maintenance
0.000E+00	Common cause failure
RC3	**Hot Leg Recirculation - Power lost to bus 3A**
7.079E-04	HLR - bus 3A lost
1.671E-04	Hardware failures
6.921E-06	Maintenance
3.460E-06	SIP-21 maintenance
3.460E-06	SIP-23 maintenance
5.339E-04	Common cause failures
RCF	**Hot Leg Recirculation - Guaranteed failure**
1.000E 00	HLR - Guaranteed failure

TABLE 3.2.-13(c)
RSS EQUATION FILE

```
HR1    1 HR1    = HR1_O + (1 - HR1_O) * (HR1_H + HR1_M + HR1_C)            $ High head recirculation (HHR) - MLOCA - All power available
HR1    2 HR1_H = SISECT + LPSECT + PIPE_F                                   $  Hardware failure
HR1    3 SISECT= MV888A *  MV888B                                           $ LP to SI crosstie
HR1    4 LPSECT= LP1H1 * (LP1H2 + LP1H3) + LP1H2 * LP1H4 + LP1H5            $   LP pump section
HR1    5 HR1_M = RHRPM + ABPM + HXM + RCPM                                  $  Maintenance
HR1   10 RHRPM = 2 * MN_RHR * (1-IPOPR1) * RHR22F * (LP1H2 + LP1H3+AB)      $   RHR pump maintenance
HR1      AB    = 2 * MN_ABP * ABP21                                         $   Aux CC unavailable due to maint.
HR1   11 ABPM  = 2 * MN_ABP * ABP21 * (LP1H1 + LP1H4)                       $   Auxiliary CCW pump maintenance
HR1   12 HXM   = 0.0                                                        $   No HX maintenance during operation
HR1   13 RCPM  = 0.0                                                        $   No RCP maintenance during operation
HR1   14 HR1_O = IPOPR2 + (1 - IPOPR2) * IPOPR3                             $  Operator Error
HR1   15 HR1_C = HR1_CS + HR1_CR + HR1_CC + HR1_CA                          $  Common cause failure
HR1   16 HR1_CS= IPVB4D * IPV04D                                            $ MOV's 888A and 888B to the SI pumps
HR1   17 HR1_CR= (IPB04S * IPP04S + IPB04R * IPP04R * T1) * HR1CR1          $    RHR pump common cause
HR1      HR1CR1= (LP1H2 + LP1H3) * (1 - IPOPR1) + 2 * MN_ABP * ABP21        $
HR1   18 HR1_CC= HR1CC1 * HR1CC2                                            $    Recirc. pump common cause
HR1      HR1CC1= IPB08S*IPP08S + IPB08R*IPP08R * T1 + IPVB4D * IPV04D       $ Including MOV's1802 A/B from the recirc pumps
HR1      HR1CC2= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LP1H1 + LP1H4         $
HR1   19 HR1_CA= (IPB06S * IPP06S + IPB06R * IPP06R * T1) * HR1CA1          $    Auxiliary CCW pump common cause
HR1      HR1CA1= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LP1H1 + LP1H4         $
HR1   20 LP1H1 = IPOPR1 + (1 - IPOPR1) * LP1H1A                             $   Total RHR (includes operator action)
HR1   21 LP1H1A= RHR21F * RHR22F + CONTSM + RHRVLS + MV885A + MV885B        $    RHR pump section
HR1   22 LP1H2 = RCP21F * RCP22F + RECISM + RCPCCW + M1802A * M1802B        $    Recirculation pump section
HR1      LP1H3 = MV745A * (HX_22F + MV747D + MV746D)                        $
HR1      LP1H4 = MV745A * HX_21F                                            $
HR1   23 LP1H5 = HX_21F * (HX_22F + MV747D + MV746D)                        $    Heat exchangers
HR2    1 HR2    = HR2_O + (1 - HR2_O) * (HR2_H + HR2_M + HR2_C)             $ HHR - MLOCA - Loss of power to bus 5A
HR2    2 HR2_H = SISECT + LPSECT + PIPE_F                                   $  Hardware failure
HR2    3 SISECT= MV888B                                                     $ LP to SI crosstie
HR2    4 LPSECT= RCP22F + RECISM + RCPCC2 + M1802B + HX_21F + MV745A        $    Recirculation pump section
HR2      RCPCC2= 4 * IPV01T * T3 + ABP22                                    $ (adjust RCP CCW for ABP22 unavail. due to bus failure)
HR2    5 HR2_M = ABPM                                                       $  Maintenance
HR2    9 ABPM  = MN_ABP                                                     $   Auxiliary CCW pump maintenance
HR2   10 HR2_O = IPOPR2 + (1 - IPOPR2) * IPOPR3                             $  Operator Error
HR2   11 HR2_C = 0                                                          $  Common cause failure
HR3    1 HR3    = HR3_O + (1 - HR3_O) * (HR3_H + HR3_M + HR3_C)             $ HHR - MLOCA - loss of power to bus 6A
HR3    2 HR3_H = SISECT + LPSECT + PIPE_F                                   $  Hardware failure
HR3    3 SISECT= MV888A                                                     $ LP to  SI pump crosstie
HR3    4 LPSECT= RCP21F + RECISM + RCPCC3 + M1802A + HX_21F + MV745A        $   LP pump section
HR3      RCPCC3= 4 * IPV01T * T3 + ABP21                                    $
HR3    5 HR3_M = ABPM                                                       $  Maintenance
HR3    9 ABPM  = MN_ABP                                                     $   Auxiliary CCW pump maintenance
HR3   10 HR3_O = IPOPR2 + (1 - IPOPR2) * IPOPR3                             $  Operator Error
HR3   11 HR3_C = 0                                                          $  Common cause failure
```

TABLE 3.2.-13(c)
RSS EQUATION FILE

```
HR4    1 HR4    = HR4_O + (1 - HR4_O) * (HR4_H + HR4_M + HR4_C)             $ HHR, MLOCA - loss of power at bus 3A
HR4    2 HR4_H  = SISECT + LPSECT + PIPE_F                                  $  Hardware failure
HR4    3 SISECT= MV888A * MV888B                                            $ LP to  SI pump crosstie
HR4    4 LPSECT= LP4H1 * (LP4H2 + LP4H3) + LP4H2 * LP4H4 + LP4H5            $   LP pump section
HR4    5 HR4_M = RHRPM + ABPM                                               $  Maintenance
HR4    9 RHRPM = MN_RHR * (1- IPOPR1)* (LP4H2 + LP4H3 + AB)                 $   RHR pump maintenance
HR4      AB    = 2 * MN_ABP * ABP21                                         $   Aux CC unavailable due to maintenance
HR4   10 ABPM  = 2 * MN_ABP * ABP21 * (LP4H1 + LP4H4)                       $   Auxiliary CCW pump maintenance
HR4   11 HR4_O = IPOPR2 + (1 - IPOPR2) * IPOPR3                             $  Operator Error
HR4   12 HR4_C = HR4_CS + HR4_CC + HR4_CA                                   $  Common cause failure
HR4      HR4_CS= IPVB4D * IPV04D                                            $      MOV's 888A and 888B to the SI pumps
HR4   14 HR4_CC= HR4CC1 * HR4CC2                                            $    Recirc. pump common cause
HR4      HR4CC1= IPB08S*IPP08S + IPB08R*IPP08R * T1 + IPVB4D * IPV04D       $      includes MOV's 1802A and 1802B from the recirculation pumps
HR4      HR4CC2= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LP4H1 + LP4H4         $
HR4   15 HR4_CA= (IPB06S * IPP06S + IPB06R * IPP06R * T1) * HR4CA1          $    Auxiliary CCW pump common cause
HR4      HR4CA1= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LP4H1 + LP4H4         $
HR4   16 LP4H1 = IPOPR1 + (1 - IPOPR1) * LP4H1A                             $   Total RHR (includes operator action)
HR4   17 LP4H1A= RHR22F + CONTSM + RHRVLS + MV885A + MV885B                 $    RHR pump section
HR4   18 LP4H2 = RCP21F * RCP22F + RECISM + RCPCCW + M1802A * M1802B        $    Recirculation pump section
HR4      LP4H3 = MV745A * (HX_22F + MV747D + MV746D)                        $
HR4      LP4H4 = MV745A * HX_21F                                            $
HR4   19 LP4H5 = HX_21F * (HX_22F + MV747D + MV746D)                        $    Heat exchangers
HR6    1 HR6    = HR6_O + (1 - HR6_O) * (HR6_H + HR6_M + HR6_C)             $ HHR - loss of the CCW system (SI pumps work)
HR6    2 HR6_H  = SISECT + LPSECT + PIPE_F                                  $  Hardware failure
HR6    3 SISECT= MV888A * MV888B                                            $ LP to  SI pump crosstie
HR6    4 LPSECT= LP6H1 + LP6H2                                              $   LP pump section
HR6      LP6H1 = IPOPR1 + (1 - IPOPR1) * LP6H1A                             $   Total RHR (includes operator action)
HR6      LP6H1A= RHR21F * RHR22F + CONTSM + RHRVLS + MV885A + MV885B        $    RHR pump section
HR6      LP6H2 = HX_21F * (HX_22F + MV747D + MV746D + MV745A)               $    Heat exchangers
HR6    5 HR6_M = RHRPM                                                      $  Maintenance
HR6   10 RHRPM = 2 * MN_RHR * (1 - IPOPR1) * RHR22F                         $   RHR pump maintenance
HR6   11 HR6_O = IPOPR2 + (1 - IPOPR2) * IPOPR3                             $  Operator Error
HR6   12 HR6_C = HR6_CS + HR6_CR                                            $  Common cause failure
HR6      HR6_CS= IPVB4D * IPV04D                                            $      MOV's 888A and 888B to the SI pumps
HR6   14 HR6_CR= IPB04S * IPP04S + IPB04R * IPP04R * T1                     $    RHR pump common cause
HR7    1 HR7    = HR7_O + (1 - HR7_O) * (HR7_H + HR7_M + HR7_C)             $ HHR, MLOCA - Loss of power to bus 5A and 3A
HR7    2 HR7_H  = SISECT + LPSECT + PIPE_F                                  $  Hardware failure
HR7    3 SISECT= MV888B                                                     $   LP to SI pump crosstie
HR7    4 LPSECT= RCP22F + RECISM + RCPCC7 + M1802B + HX_21F + MV745A        $   Recirculation pump section
HR7      RCPCC7= 4 * IPV01T * T3 + ABP22                                    $
HR7    5 HR7_M = ABPM                                                       $   maintenance
HR7    7 ABPM  = MN_ABP                                                     $   Auxiliary CCW pump maintenance
HR7    8 HR7_O = IPOPR2 + (1 - IPOPR2) * IPOPR3                             $  Operator Error
HR7    9 HR7_C = 0.00                                                       $  Common cause failure
```

TABLE 3.2-13(C)
RSS EQUATION FILE

```
HR8    1 HR8    = HR8_O + (1 - HR8_O) * (HR8_H + HR8_M + HR8_C)        $ HHR, MLOCA - LOSS of power to bus 6A and 3A
HR8    2 HR8_H = SISECT + LPSECT + PIPE_F                             $  Hardware failure
HR8    3 SISECT= MV888A                                               $   SI pump section
HR8    4 LPSECT= RCP21F + RECISM + RCPCC8 + M1802A + HX_21F + MV745A  $   LP pump section
HR8      RCPCC8= RCPCCW + ABP21 * (1 - ABP22)                         $
HR8    5 HR8_M = ABPM                                                 $  maintenance
HR8    7 ABPM  = MN_ABP                                               $   Auxiliary CCW pump maintenance
HR8    8 HR8_O = IPOPR2 + (1 - IPOPR2) * IPOPR3                       $  Operator Error
HR8    9 HR8_C = 0.00                                                 $  Common cause failure
HRA    1 HRA   = HRA_O + (1 - HRA_O) * (HRA_H + HRA_M + HRA_C)        $ High head recirculation (HHR) - SLOCA - All power available
HRA    2 HRA_H = SISECT + LPSECT + PIPE_F                             $  Hardware failure
HRA    3 SISECT= MV888A *  MV888B                                     $ LP to SI crosstie
HRA    4 LPSECT= LP1H1 * (LP1H2 + LP1H3) + LP1H2 * LP1H4 + LP1H5      $   LP pump section
HRA    5 HRA_M = RHRPM + ABPM + HXM + RCPM                            $  Maintenance
HRA   10 RHRPM = 2 * MN_RHR * (1-IPOPR1) * RHR22F * (LP1H2 + LP1H3+AB) $   RHR pump maintenance
HRA      AB    = 2 * MN_ABP * ABP21                                   $   Aux CC unavailable due to maint.
HRA   11 ABPM  = 2 * MN_ABP * ABP21 * (LP1H1 + LP1H4)                 $   Auxiliary CCW pump maintenance
HRA   12 HXM   = 0.0                                                  $   No HX maintenance during operation
HRA   13 RCPM  = 0.0                                                  $   No RCP maintenance during operation
HRA   14 HRA_O = IPOPRA + (1 - IPOPRA) * IPOPR3                       $  Operator Error
HRA   15 HRA_C = HRA_CS + HRA_CR + HRA_CC + HRA_CA                    $  Common cause failure
HRA   16 HRA_CS= IPVB4D * IPV04D                                      $      MOV's 888A and 888B to the SI pumps
HRA   17 HRA_CR= (IPB04S * IPP04S + IPB04R * IPP04R * T1) * HRACR1    $    RHR pump common cause
HRA      HRACR1= (LP1H2 + LP1H3) * (1 - IPOPR1) + 2 * MN_ABP * ABP21  $
HRA   18 HRA_CC= HRACC1 * HRACC2                                      $    Recirc. pump common cause
HRA      HRACC1= IPB08S*IPP08S + IPB08R*IPP08R * T1 + IPVB4D * IPV04D $      includes MOV's 1802A and 1802B from the recirc. pumps
HRA      HRACC2= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LP1H1 + LP1H4   $
HRA   19 HRA_CA= (IPB06S * IPP06S + IPB06R * IPP06R * T1) * HRACA1    $    Auxiliary CCW pump common cause
HRA      HRACA1= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LP1H1 + LP1H4   $
HRA   20 LP1H1 = IPOPR1 + (1 - IPOPR1) * LP1H1A                       $  Total RHR (includes operator action)
HRA   21 LP1H1A= RHR21F * RHR22F + CONTSM + RHRVLS + MV885A + MV885B  $    RHR pump section
HRA   22 LP1H2 = RCP21F * RCP22F + RECISM + RCPCCW + M1802A * M1802B  $    Recirculation pump section
HRA      LP1H3 = MV745A * (HX_22F + MV747D + MV746D)                  $
HRA      LP1H4 = MV745A * HX_21F                                      $
HRA   23 LP1H5 = HX_21F * (HX_22F + MV747D + MV746D)                  $    Heat exchangers
HRB    1 HRB   = HRB_O + (1 - HRB_O) * (HRB_H + HRB_M + HRB_C)        $ HHR, SLOCA - Loss of power to bus 5A
HRB    2 HRB_H = SISECT + LPSECT + PIPE_F                             $  Hardware failure
HRB    3 SISECT= MV888B                                               $ LP to SI crosstie
HRB    4 LPSECT= RCP22F + RECISM + RCPCC2 + M1802B + HX_21F + MV745A  $    Recirculation pump section
HRB      RCPCC2= 4 * IPV01T * T3 + ABP22                              $    (adjust RCPCCW for ABP22 unavail. due to bus failure)
HRB    5 HRB_M = ABPM                                                 $  Maintenance
HRB    9 ABPM  = MN_ABP                                               $   Auxiliary CCW pump maintenance
HRB   10 HRB_O = IPOPRA + (1 - IPOPRA) * IPOPR3                       $  Operator Error
HRB   11 HRB_C = 0                                                    $  Common cause failure
HRC    1 HRC   = HRC_O + (1 - HRC_O) * (HRC_H + HRC_M + HRC_C)        $ HHR, SLOCA - loss of power to bus 6A
HRC    2 HRC_H = SISECT + LPSECT + PIPE_F                             $  Hardware failure
HRC    3 SISECT= MV888A                                               $ LP to  SI pump crosstie
HRC    4 LPSECT= RCP21F + RECISM + RCPCC3 + M1802A + HX_21F + MV745A  $   LP pump section
HRC      RCPCC3= 4 * IPV01T * T3 + ABP21                              $
HRC    5 HRC_M = ABPM                                                 $  Maintenance
HRC    9 ABPM  = MN_ABP                                               $   Auxiliary CCW pump maintenance
HRC   10 HRC_O = IPOPRA + (1 - IPOPRA) * IPOPR3                       $  Operator Error
HRC      HRC_C = 0.00                                                 $  Common cause failure
```

TABLE 3.2-13(c)
RSS EQUATION FILE

```
HRD     1 HRD    = HRD_O + (1 - HRD_O) * (HRD_H + HRD_M + HRD_C)            $ HHR, SLOCA - loss of power at bus 3A
HRD     2 HRD_H  = SISECT + LPSECT + PIPE_F                                 $  Hardware failure
HRD     3 SISECT= MV888A * MV888B                                           $ LP to  SI pump crosstie
HRD     4 LPSECT= LP4H1 * (LP4H2 + LP4H3) + LP4H2 * LP4H4 + LP4H5           $   LP pump section
HRD     5 HRD_M = RHRPM + ABPM                                              $  Maintenance
HRD     9 RHRPM = MN_RHR * (1- IPOPR1)* (LP4H2 + LP4H3 + AB)                $   RHR pump maintenance
HRD       AB    = 2 * MN_ABP * ABP21                                        $   Aux CC unavailable due to maintenance
HRD    10 ABPM  = 2 * MN_ABP * ABP21 * (LP4H1 + LP4H4)                      $   Auxiliary CCW pump maintenance
HRD    11 HRD_O = IPOPRA + (1 - IPOPRA) * IPOPR3                            $  Operator Error
HRD    12 HRD_C = HRD_CS + HRD_CC + HRD_CA                                  $  Common cause failure
HRD       HRD_CS= IPVB4D * IPV04D                                           $      MOV's 888A and 888B to the SI pumps
HRD    14 HRD_CC= HRDCC1 * HRDCC2                                           $    Recirc. pump common cause
HRD       HRDCC1= IPB08S*IPP08S + IPB08R*IPP08R * T1 + IPVB4D * IPV04D      $      includes MOV's 1802A and 1802B from the recirc. pumps
HRD       HRDCC2= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LP4H1 + LP4H4        $
HRD    15 HRD_CA= (IPB06S * IPP06S + IPB06R * IPP06R * T1) * HRDCA1         $    Auxiliary CCW pump common cause
HRD       HRDCA1= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LP4H1 + LP4H4        $
HRD    16 LP4H1 = IPOPR1 + (1 - IPOPR1) * LP4H1A                            $   Total RHR (includes operator action)
HRD    17 LP4H1A= RHR22F + CONTSM + RHRVLS + MV885A + MV885B                $    RHR pump section
HRD    18 LP4H2 = RCP21F * RCP22F + RECISM + RCPCCW + M1802A * M1802B       $    Recirculation pump section
HRD       LP4H3 = MV745A * (HX_22F + MV747D + MV746D)                       $
HRD       LP4H4 = MV745A * HX_21F                                           $
HRD    19 LP4H5 = HX_21F * (HX_22F + MV747D + MV746D)                       $    Heat exchangers
HRG     1 HRGTOP=
HRG     2 HRG_H = SISECT + LPSECT + PIPE_F                                  $  Hardware failure
HRG     3 SISECT= MV888A * MV888B                                           $ LP to  SI pump crosstie
HRG     4 LPSECT= LP6H1 + LP6H2                                             $   LP pump section
HRG       LP6H1 = IPOPR1 + (1 - IPOPR1) * LP6H1A                            $   Total RHR (includes operator action)
HRG       LP6H1A= RHR21F * RHR22F + CONTSM + RHRVLS + MV885A + MV885B       $    RHR pump section
HRG       LP6H2 = HX_21F * (HX_22F + MV747D + MV746D + MV745A)              $    Heat exchangers
HRG     5 HRG_M = RHRPM                                                     $  Maintenance
HRG    10 RHRPM = 2 * MN_RHR * (1 - IPOPR1) * RHR22F                        $   RHR pump maintenance
HRG    11 HRG_O = IPOPRA + (1 - IPOPRA) * IPOPR3                            $  Operator Error
HRG    12 HRG_C = HRG_CS + HRG_CR                                           $  Common cause failure
HRG       HRG_CS= IPVB4D * IPV04D                                           $      MOV's 888A and 888B to the SI pumps
HRG    14 HRG_CR= IPB04S * IPP04S + IPB04R * IPP04R * T1                    $    RHR pump common cause
HRH     1 HRH    = HRH_O + (1 - HRH_O) * (HRH_H + HRH_M + HRH_C)            $ HHR,SLOCA - Loss of power to bus 5A and 3A
HRH     2 HRH_H = SISECT + LPSECT + PIPE_F                                  $  Hardware failure
HRH     3 SISECT= MV888B                                                    $   LP to SI pump crosstie
HRH     4 LPSECT= RCP22F + RECISM + RCPCC7 + M1802B + HX_21F + MV745A       $   Recirculation pump section
HRH       RCPCC7= 4 * IPV01T * T3 + ABP22                                   $
HRH     5 HRH_M = ABPM                                                      $   maintenance
HRH     7 ABPM  = MN_ABP                                                    $   Auxiliary CCW pump maintenance
HRH     8 HRH_O = IPOPRA + (1 - IPOPRA) * IPOPR3                            $  Operator Error
HRH     9 HRH_C = 0.00                                                      $  Common cause failure
HRI     1 HRI    = HRI_O + (1 - HRI_O) * (HRI_H + HRI_M + HRI_C)            $ HHR,SLOCA - loss of power to bus 6A and 3A
HRI     2 HRI_H = SISECT + LPSECT + PIPE_F                                  $  Hardware failure
HRI     3 SISECT= MV888A                                                    $   SI pump section
HRI     4 LPSECT= RCP21F + RECISM + RCPCC8 + M1802A + HX_21F + MV745A       $   LP pump section
HRI       RCPCC8= RCPCCW + ABP21 * (1 - ABP22)                              $
HRI     5 HRI_M = ABPM                                                      $  maintenance
HRI     7 ABPM  = MN_ABP                                                    $   Auxiliary CCW pump maintenance
HRI     8 HRI_O = IPOPRA + (1 - IPOPRA) * IPOPR3                            $  Operator Error
HRI     9 HRI_C = 0.0                                                       $  Common Cause
HRF     1 HRF    = 1.0                                                      $ HHR - Guaranteed failure High Head Recirculation
```

TABLE 3.2-13(c)
RSS EQUATION FILE

```
LR1     1 LR1    = LR1_O + (1 - LR1_O) * (LR1_H + LR1_M + LR1_C)            $ Low Head Recirculation (LHR) - All power available
LR1     2 LR1_H = LR1H1*(LR1H2 + LR1H3) + LR1H2 * LR1H4 + LR1H5 + LR1H6     $  Hardware
LR1     3 LR1_M = RHRPM + ABPM                                               $  Maintenance
LR1     4 RHRPM  = 2 * MN_RHR * (1-IPOPR5) * RHR22F * (LR1H2 + LR1H3)        $   Single RHR pump maintenance
LR1     5 ABPM   = 2 * MN_ABP * ABP21 * (LR1H1 + LR1H4)                      $   Auxiliary CCW pump maintenance
LR1     6 LR1_O = IPOPR6                                                     $  Operator error
LR1     7 LR1_C = LR1_CR + LR1_CC + LR1_CA                                   $  Common cause failure
LR1     8 LR1_CR= (IPB04S * IPP04S + IPB04R * IPP04R * T1) * LR1CR1          $    RHR pump common cause
LR1       LR1CR1= (LR1H2 + LR1H3) * (1 - IPOPR5) + 2 * MN_ABP * ABP21        $
LR1     9 LR1_CC= LR1CC1 * LR1CC2                                            $    Recirc. pump common cause
LR1       LR1CC1= IPB08S*IPP08S + IPB08R*IPP08R * T1 + IPVB4D * IPV04D       $ Include MOV's 1802A/B from  recirc. pumps
LR1       LR1CC2= 2 * MN_RHR * (1 - IPOPR5) * RHR22F + LR1H1 + LR1H4         $
LR1    10 LR1_CA= (IPB06S * IPP06S + IPB06R * IPP06R * T1) * LR1CA1          $    Auxiliary CCW pump common cause
LR1       LR1CA1= 2 * MN_RHR * (1 - IPOPR5) * RHR22F + LR1H1 + LR1H4         $
LR1    12 LR1H1 = IPOPR5 + (1 - IPOPR5) * LR1H1A                             $   Operator error - shift to RHR pumps
LR1    13 LR1H1A= RHR21F * RHR22F + CONTSM + MV885A + MV885B + RHRVLS        $   RHR pump path
LR1    14 LR1H2 = RCP21F * RCP22F + RECISM + M1802A * M1802B + RCPCCW        $   Internal recirculation pump flow path
LR1       LR1H3 = MV745A * (HX_22F + MV746F)                                 $
LR1       LR1H4 = MV745A * (HX_21F + MV747F)                                 $
LR1    15 LR1H5 = (HX_22F + MV746F + MV822A)*(HX_21F + MV747F)               $   Heat exchanger paths
LR1    16 LR1H6 = CV897B * (CV897C + CV897D) + CV897C * CV897D               $ Injection paths (need 2 loops, 1 disabled by LOCA)
LR2     1 LR2    = LR2_O + (1 - LR2_O) * (LR2_H + LR2_M + LR2_C)            $ LHR  - loss of power to bus 5A or 6A
LR2     2 LR2_H = LR2H1 + LR2H2 + LR2H3 + LR2H4                              $  Hardware
LR2     3 LR2_M = MN_ABP                                                     $  Auxiliary CCW pump maintenance
LR2     4 LR2_O = IPOPR6                                                     $  Operator error
LR2     5 LR2_C = 0.00                                                       $  Other causes
LR2     6 LR2H1 = RCP22F + RECISM + M1802B + RCPCC2                          $   Internal recirculation pump flow path
LR2       RCPCC2= RCPCCW + ABP22 * (1 - ABP21)                               $
LR2       LR2H2 = MV745A                                                     $
LR2     7 LR2H3 = HX_21F + MV747F                                            $   Heat exchanger paths
LR2     8 LR2H4 = CV897B * (CV897C + CV897D) + CV897C * CV897D               $   Injection paths
LR3     1 LR3    = LR3_O + (1 - LR3_O) * (LR3_H + LR3_M + LR3_C)            $ LHR - loss of power to bus 3A
LR3     2 LR3_H = LR3H1*(LR3H2 + LR3H3) + LR3H2 * LR3H4 + LR3H5 + LR3H6     $  Hardware
LR3     3 LR3_M = RHRPM + ABPM                                               $  Maintenance
LR3     4 RHRPM = MN_RHR                                                     $   RHR pump maintenance
LR3     5 ABPM   = 2 * MN_ABP * ABP21 * (LR3H1 + LR3H4)                      $   Auxiliary CCW pump maintenance
LR3     6 LR3_O = IPOPR6                                                     $  Operator error
LR3     7 LR3_C = LR3_CC + LR3_CA + LR3_CH                                   $  Common cause contribution
LR3     8 LR3_CC= LR3CC1 * LR3CC2                                            $    Recirc. pump common cause
LR3       LR3CC1= IPB08S*IPP08S + IPB08R*IPP08R * T1 + IPVB4D * IPV04D       $ Including MOV's 1802/B from recirc. pumps
LR3       LR3CC2= MN_RHR * (1 - IPOPR5) * RHR22F + LR3H1 + LR3H4             $
LR3     9 LR3_CA= (IPB06S * IPP06S + IPB06R * IPP06R * T1) * LR3CA1          $    Auxiliary CCW pump common cause
LR3    10 LR3_CH= IPVB4D * IPV04D                                            $    Common cause valve failure
LR3       LR3CA1= MN_RHR * (1 - IPOPR5) * RHR22F + LR3H1 + LR3H4             $
LR3    11 LR3H1 = IPOPR5 + (1 - IPOPR5) * LR3H1A                             $   Operator error - shift to RHR pumps
LR3    12 LR3H1A= RHR22F + CONTSM + MV885A + MV885B + RHRVLS                 $    RHR pump path
LR3    13 LR3H2 = RCP21F * RCP22F + RECISM + M1802A * M1802B + RCPCCW        $   Internal recirculation pump flow path
LR3       LR3H3 = MV745A * (HX_22F + MV746F)                                 $
LR3       LR3H4 = MV745A * (HX_21F + MV747F)                                 $
LR3    14 LR3H5 = (HX_22F + MV746F + MV822A)*(HX_21F + MV747F)               $   Heat exchanger paths
LR3    15 LR3H6 = CV897B * (CV897C + CV897D) + CV897C * CV897D               $   Injection paths
```

TABLE 3.2-13(c)
RSS EQUATION FILE

```
LRA     1 LRA    = LRAH1 + LRAH2 + LRA_M + LRA_C                         $   LHR - CCW lost - all power availble
LRA     2 LRAH1 = IPOPR6 + IPOPR5 + (T - IPOPR6) * LRAH1A                $   Opeartor and Hardware Failures
LRA     3 LRAH1A= RHR21F * RHR22F + CONTSM + RHRVLS + MV885A + MV885B    $     RHR pump section
LRA     4 LRAH2 = HX_21F * (HX_22F + MV747D + MV746D + MV745A)           $     Heat exchangers
LRA     5 LRA_M = RHRPM                                                  $   Maintenance
LRA     6 LRA_C = IPB04S * IPP04S + IPB04R * IPP04R * T1                 $     RHR pump common cause
LRA     7 RHRPM = 2 * MN_RHR * (1 - IPOPR6) * RHR22F                     $    RHR pump maintenance
LRB     1 LRB    = LRBH1 + LRBH2 + LRB_M                                 $ LHR CCW fand Bus 3A lost
LRB     2 LRBH1 = IPOPR6 + IPOPR5 + (T - IPOPR6) * LRBH1A                $   Opeartor and Hardware Failures
LRB     3 LRBH1A= RHR21F * RHR22F + CONTSM + RHRVLS + MV885A + MV885B    $     RHR pump section
LRB     4 LRBH2 = HX_21F * (HX_22F + MV747D + MV746D + MV745A)           $     Heat exchangers
LRB     5 LRB_M = MN_RHR                                                 $   Maintenance
LR6     1 LR6    = LR6_O + (1 - LR6_O) * (LR6_H + LR6_M + LR6_C)         $ LHR - All power available
LR6     2 LR6_H = LR6H1*(LR6H2 + LR6H3) + LR6H2 * LR6H4 + LR6H5 + LR6H6  $   Hardware
LR6     3 LR6_M = RHRPM + ABPM                                           $   Maintenance
LR6     4 RHRPM = 2 * MN_RHR * (1-IPOPR1) * RHR22F * (LR6H2 + LR6H3)     $    Single RHR pump maintenance
LR6     5 ABPM   = 2 * MN_ABP * ABP21 * (LR6H1 + LR6H4)                  $    Auxiliary CCW pump maintenance
LR6     6 LR6_O = IPOPR4                                                 $   Operator error
LR6     7 LR6_C = LR6_CR + LR6_CC + LR6_CA                               $   Common cause failure
LR6     8 LR6_CR= (IPB04S * IPP04S + IPB04R * IPP04R * T1) * LR6CR1      $     RHR pump common cause
LR6       LR6CR1= (LR6H2 + LR6H3) * (1 - IPOPR1) + 2 * MN_ABP * ABP21    $
LR6     9 LR6_CC= LR6CC1 * LR6CC2                                        $    Recirc. pump common cause
LR6       LR6CC1= IPB08S*IPP08S + IPB08R*IPP08R * T1 + IPVB4D * IPV04D   $ Including MOV's 1802 A/B from recirc pumps
LR6       LR6CC2= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LR6H1 + LR6H4     $
LR6    10 LR6_CA= (IPB06S * IPP06S + IPB06R * IPP06R * T1) * LR6CA1      $     Auxiliary CCW pump common cause
LR6    11 LR6CA1= 2 * MN_RHR * (1 - IPOPR1) * RHR22F + LR6H1 + LR6H4     $
LR6    12 LR6H1 = IPOPR1 + (1 - IPOPR1) * LR6H1A                         $    Operator error - shift to RHR pumps
LR6    13 LR6H1A= RHR21F * RHR22F + CONTSM + MV885A + MV885B + RHRVLS    $    RHR pump path
LR6    14 LR6H2 = RCP21F * RCP22F + RECISM + M1802A * M1802B + RCPCCW    $    Internal recirculation pump flow path
LR6       LR6H3 = MV745A * (HX_22F + MV746F)                             $
LR6       LR6H4 = MV745A * (HX_21F + MV747F)                             $
LR6    15 LR6H5 = (HX_22F + MV746F + MV822A)*(HX_21F + MV747F)           $   Heat exchanger paths
LR6    16 LR6H6 = CV897B * (CV897C + CV897D) + CV897C * CV897D           $    Injection paths (need 2 loops, 1 disabled by LOCA)
```

TABLE 3.2-13(c)
RSS EQUATION FILE

```
LR7     1 LR7    = LR7_O + (1 - LR7_O) * (LR7_H + LR7_M + LR7_C)          $ LHR - loss of Power to bus 5
LR7     2 LR7_H  = LR7H1 + LR7H2 + LR7H3 + LR7H4                           $  Hardware
LR7     3 LR7_M  = MN_ABP                                                  $  Auxiliary CCW pump maintenance
LR7     4 LR7_O  = IPOPR4                                                  $  Operator error
LR7     5 LR7_C  = 0.00                                                    $  Other causes
LR7     6 LR7H1  = RCP22F + RECISM + M1802B + RCPCC2                       $   Internal recirculation pump flow path
LR7       RCPCC2= RCPCCW + ABP22 * (1 - ABP21)                             $
LR7       LR7H2  = MV745A                                                  $
LR7     7 LR7H3  = HX_21F + MV747F                                         $   Heat exchanger paths
LR7     8 LR7H4  = CV897B * (CV897C + CV897D) + CV897C * CV897D            $  Injection paths
LR8     1 LR8    = LR8_O + (1 - LR8_O) * (LR8_H + LR8_M + LR8_C)          $ LHR- loss of power to bus 3
LR8     2 LR8_H  = LR8H1*(LR8H2 + LR8H3) + LR8H2 * LR8H4 + LR8H5 + LR8H6   $  Hardware
LR8     3 LR8_M  = RHRPM + ABPM                                            $  Maintenance
LR8     4 RHRPM  = MN_RHR                                                  $   RHR pump maintenance
LR8     5 ABPM   = 2 * MN_ABP * ABP21 * (LR8H1 + LR8H4)                    $   Auxiliary CCW pump maintenance
LR8     6 LR8_O  = IPOPR4                                                  $  Operator error
LR8     7 LR8_C  = LR8_CC + LR8_CA + LR8_CH                                $  Common cause contribution
LR8     8 LR8_CC= LR8CC1 * LR8CC2                                          $    Recirc. pump common cause
LR8       LR8CC1= IPB08S*IPP08S + IPB08R*IPP08R * T1 + IPVB4D * IPV04D     $    MOV's 1802A/B from recirc. pumps
LR8       LR8CC2= MN_RHR * (1 - IPOPR1) * RHR22F + LR8H1 + LR8H4           $    Common cause
LR8     9 LR8_CA= (IPB06S * IPP06S + IPB06R * IPP06R * T1) * LR8CA1        $    Auxiliary CCW pump common cause
LR8       LR8CA1= MN_RHR * (1 - IPOPR1) * RHR22F + LR8H1 + LR8H4           $     Common cause
LR8    10 LR8_CH= IPVB4D * IPV04D                                          $     Common cause
LR8    11 LR8H1  = IPOPR1 + (1 - IPOPR1) * LR8H1A                          $   Operator error - shift to RHR pumps
LR8    12 LR8H1A= RHR22F + CONTSM + MV885A + MV885B + RHRVLS               $    RHR pump path
LR8    13 LR8H2  = RCP21F * RCP22F + RECISM + M1802A * M1802B + RCPCCW     $   Internal recirculation pump flow path
LR8       LR8H3  = MV745A * (HX_22F + MV746F)                              $
LR8       LR8H4  = MV745A * (HX_21F + MV747F)                              $
LR8    14 LR8H5  = (HX_22F + MV746F + MV822A)*(HX_21F + MV747F)            $   Heat exchanger paths
LR8    15 LR8H6  = CV897B * (CV897C + CV897D) + CV897C * CV897D            $   Injection paths
LRC     1 LRC    = LRCH1 + LRCH2 + LRC_M + LRC_C                           $   LHR - CCW failed - all power availble
LRC     2 LRCH1  = IPOPR4 + IPOPR1 + (T - IPOPR4) * LRCH1A                 $   Opeartor and Hardware Failures
LRC     3 LRCH1A= RHR21F * RHR22F + CONTSM + RHRVLS + MV885A + MV885B      $    RHR pump section
LRC     4 LRCH2  = HX_21F * (HX_22F + MV747D + MV746D + MV745A)            $    Heat exchangers
LRC     5 LRC_M  = RHRPM                                                   $  Maintenance
LRC     6 LRC_C  = IPB04S * IPP04S + IPB04R * IPP04R * T1                  $    RHR pump common cause
LRC     7 RHRPM  = 2 * MN_RHR * (1 - IPOPR4) * RHR22F                      $   RHR pump maintenance
LRD     1 LRD    = LRDH1 + LRDH2 + LRD_M                                   $   LHR - CCW failed - all power availble
LRD     2 LRDH1  = IPOPR4 + IPOPR1 + (T - IPOPR4) * LRDH1A                 $   Opeartor and Hardware Failures
LRD     3 LRDH1A= RHR21F * RHR22F + CONTSM + RHRVLS + MV885A + MV885B      $    RHR pump section
LRD     4 LRDH2  = HX_21F * (HX_22F + MV747D + MV746D + MV745A)            $    Heat exchangers
LRD     5 LRD_M  = MN_RHR                                                  $  Maintenance
```

TABLE 3.2-13(c)
RSS EQUATION FILE

LR4	1	RR1TOP= RR1_H + RR1_M + RR1_C + RR1_OP	$ RHR Shutdown Cooling Mode - All power available
LR4	2	RR1_H = RR1H1 + (RRTH3 * RRTH4) + RR1H5	$ Hardware total
LR4	3	RR1H1 = RHR21F * RHR22F + RHRHLS + RHRVLS	$ Hardware
LR4	4	RHRHLS= MOV730 + MOV731	$ Hot Leg Suction Valves
LR4	5	RR1H3 = MV745A + HX_22F + MOV746 + MV745B	$ Heat Exchanger Path
LR4	6	RR1H4 = HX_21F + MOV747	$ Heat Exchanger Path
LR4	7	RR1H5 = CV897B * (CV897C + CV897D) + CV897C * CV897D	$ Injection Path
LR4	8	RR1_M = 2 * MN_RHR * RHR22F	$ RHR maintenance
LR4	9	RR1_C = RR1C1 + RR1C2	$ Common cause total
LR4	10	RR1C1 = IPB04S * IPP04S + IPB04R * IPP04R * T1	$ Common cause - pumps
LR4	11	RR1C2 = IPVB4D * IPV04D	$ Common cause - 746 & 747
LR4	12	RR1_OP= IPOPRH	$ Operator fails to initiate S/D cooling
LR5	1	RR2TOP= RR2_H + RR2_M + RR2_C + RR2_OP	$ RHR shutdown cooling - loss of bus 3A
LR5	2	RR2_H = RR2H1 + (RR2H3 * RR2H4) + RR2H5	$ RHR Hardware failures
LR5	3	RR2H1 = RHR22F + RHRHLS + RHRVLS	$ Hardware
LR5	4	RHRHLS= MOV730 + MOV731	$ Hardware
LR5	5	RR2H3 = MV745A + HX_22F +MOV746 + MV745B	$ Hardware
LR5	6	RR2H4 = HX_21F + MOV747	$ Hardware
LR5	7	RR2H5 = CV897B * (CV897C + CV897D) + CV897C * CV897D	$ Hardware
LR5	8	RR2_M = MN_RHR	$ RHR Maintenance
LR5	9	RR2_C = IPVB4D * IPV04D	$ Common Cause
LR5		RR2_OP= IPOPRH	$ Operator fails to Initiate S/D cooling
LRF	1	LPF = 1.0	$ Guarentеed failure of LHR
RH1	1	RH1TOP= RH1_H + RH1_C	$ Recirculation Heat Removal - All power available.
RH1	2	RH1_H = (MV822B + MOV747) * MV822A + RH1H1	$ Hardware total
RH1	3	RH1H1 = (MV822A + MOV746) * MV822B	$ Hardware
RH1	4	RH1_C = IPVB4D * IPV04D	$ Common Cause failure 822A/822B
RH2	1	RH2TOP= RH2_H	$ Recirculation Heat Remval - Loss of bus 5A or 6A
RH2	2	RH2_H = MV822A + MOV747	$ Hardware
RHF	1	RHF = 1.0	$ Guarenteed failure of RH
RC1	1	RC1 = RC1_H + RC1_M + RC1_C	$ Hot Leg Recirculation (HLR) - all power available
RC1	2	RC1_H = PATH23 * PATH21 + MV888A * MV888B + RC1H1	$ Hardware Failure
RC1		RC1H1 = PATH23 * SIP21F * (SIP22F + SIP2A) + RC1H2	$
RC1		RC1H2 = PATH21 * SIP23F * (SIP22F + SIP2B) + RC1H3 + RC1H4	$
RC1		RC1H3 = SIP21F * SIP22F * SIP23F - PMP21 * PMP23 * SIP22F	$
RC1		RC1H4 = (PMP21 + VLV21 * MV851B) * (PMP23 + VLV23 * MV851A)	$
RC1	3	RC1_M = SIP21M + SIP22M + SIP23M	$ SI pump maintenance

TABLE 3.2-13(c)
RSS EQUATION FILE

```
RC1     4 SIP21M= MN_SIP * (PMP23 + SIP22F * VLV23 + SIP1M1 + SIP1M2)      $   SIP-21 maintenance
RC1       SIP1M1= (SIP22F + MV851A) * PATH23                               $
RC1       SIP1M2= VLV23 * (MV851A + PATH21)                                $
RC1     5 SIP22M= MN_SIP * (SIP21F * SIP23F + SIP2M1)                      $   SIP-22 maintenance
RC1       SIP2M1= SIP21F * PATH23 + SIP23F * PATH21                        $
RC1     6 SIP23M= MN_SIP * (PMP21 + SIP22F * VLV21 + SIP3M1 + SIP3M2)      $   SIP-23 maintenance
RC1       SIP3M1= (SIP22F + MV851B) * PATH21                               $
RC1       SIP3M2= VLV21 * (MV851B + PATH23)                                $
RC1     7 RC1_C = RC1C1 + RC1C2 + RC1C3 + RC1C4                            $   SI pump common cause (incl. MOV's)
RC1       RC1C1 = IPB03S * IPP03S * (IPG03S + 1/2 * (1-IPG03S))            $
RC1       RC1C2 = IPB03R * IPP03R * (IPG03S + 1/2 * (1-IPG03S)) * T1       $
RC1       RC1C3 = (RC1C31 + RC1C32) * (RC1C33 + RC1C34)                    $
RC1       RC1C31= 1/2 * IPB03S * (1-IPG03S) * IPP03S                       $
RC1       RC1C32= 1/2 * IPB03R * (1-IPG03R) * IPP03R * T1                  $
RC1       RC1C33= PATH21 + PATH23                                          $
RC1       RC1C34= SIP21F + SIP23F + 2 * MN_SIP                             $
RC1       RC1C4 = 2 * IPVB4D * IPV04D                                      $     MOV's 888A/888B, or 856B/856F
RC1       PATH21= MV856B + 2 * IPV02D                                      $  MOV + 2 check valves
RC1       PATH23= MV856F + 2 * IPV02D                                      $  MOV + 2 check valves
RC1       SIP2A = IPV02D + IPV01T * T1                                     $
RC1       SIP2B = IPV02D + IPV01T * T1                                     $
RC2     1 RC2   = RC2_H + RC2_M + RC2_C                                    $ HLR - loss of bus 5A or 6A
RC2     2 RC2_H = PATH21 + MV888B + SIP22F + SIP2A                         $   Hardware Failure
RC2     3 RC2_M = MN_SIP                                                   $   Maintenance on SI pump 22
RC2     4 RC2_C = 0.0                                                      $   Common cause failure
RC2       PATH21= MV856B + 2 * IPV02D                                      $   MOV + 2 check valves
RC2       SIP2A = IPV02D + IPV01T * T1                                     $
RC3     1 RC3   = RC3_H + RC3_M + RC3_C                                    $ HLR - loss of power to bus 3A
RC3     2 RC3_H = PATH23 * PATH21 + MV888A * MV888B + RC3H1                $   Hardware Failure
RC3       RC3H1 = PATH21 * SIP23F + PATH23 * SIP21F + SIP21F * SIP23F      $
RC3     3 RC3_M = SIP21M + SIP23M                                          $   SI pump maintenance
RC3     4 SIP21M= MN_SIP * (SIP23F + PATH23)                               $     SIP-21 maintenance
RC3     5 SIP23M= MN_SIP * (SIP21F + PATH21)                               $     SIP-23 maintenance
RC3     6 RC3_C = RC3C1 + RC3C2 + RC3C3                                    $   SI pump common cause (incl. MOV's)
RC3       RC3C1 = IPB03S * IPP03S * (1/2*(1-IPG03S) + IPG03S)              $
RC3       RC3C2 = IPB03R * IPP03R * (1/2*(1-IPG03R) + IPG03R) * T1         $
RC3       RC3C3 = 2 * IPVB4D * IPV04D                                      $     MOV's 888A/888B, or 856B/856F
RC3       PATH21= MV856B + 2 * IPV02D                                      $
RC3       PATH23= MV856F + 2 * IPV02D                                      $
RCF     1 RCF   = 1.0                                                      $ Guaranteed Failure of HLR
          RHR21F= IPP03S + IPV02D + (IPP04R + 2 * IPV01T) * T1             $  RHR pump 21 restart and run
          RHR22F= IPP03S + IPV02D + (IPP04R + 2 * IPV01T) * T1             $  RHR pump 22 restart and run
          RCP21F= IPP03S + IPV02D + 2 * IPV01T * T3 + RCP_R                $  Recirculation pump 21 start and run, valves 751A and 752A
          CP22F= IPP03S + IPV02D + 2 * IPV01T * T3 + RCP_R                 $  Recirculation pump 22 start and run, valves 751B and 752B
          RCP_R = (IPP08R + 2 * IPV01T) * T1                               $  Recirculation pump run
          SIP21F= IPP03S + IPV02D + (IPP03R + 2 * IPV01T) * T1             $  Safety injection pump 21 restart and run
          PMP21 = IPP03S + (IPP03R + IPV01T) * T1                          $   Intake valve and pump
          VLV21 = IPV02D + IPV01T * T1                                     $   Discharge check valve and MOV
          SIP22F= IPP03S + IPV02D + (IPP03R + 2 * IPV01T) * T1             $  Safety injection pump 22 restart and run
          SIP23F= IPP03S + IPV02D + (IPP03R + 2 * IPV01T) * T1             $  Safety injection pump 23 restart and run
          PMP23 = IPP03S + (IPP03R + IPV01T) * T1                          $   Intake valve and pump
          VLV23 = IPV02D + IPV01T * T1                                     $   Discharge check valve and MOV
          RCPCCW= 4 * IPV01T * T3 + ABP21 * ABP22                          $  CCW valves 753A + 753B + 753G + 753H; CCW booster pumps
```

TABLE 3.2-13(c)
RSS EQUATION FILE

```
ABP21 = IPP03S + IPV02D + 2 * IPV01T * T3 + ABP_R        $ CCW booster pump 21 start/run; CV755A; MV's 753C and 753E
ABP22 = IPP03S + IPV02D + 2 * IPV01T * T3 + ABP_R        $ CCW booster pump 22 start/run; CV755B; MV's 753D and 753F
ABP_R = (IPP06R + 2 * IPV01T) * T1                       $ CCW booster pump run
HX_21F= (IPH01L + IPV01T) * T1                           $ Heat exchanger 21 + valve 742
HX_22F= IPH01L * T1                                      $ Heat exchanger 22
RECISM= IPS02P * T1                                      $ Recirculation sump
CONTSM= IPV01T * T4 + IPS03P * T1                        $ Containment sump + MV1805
CV897B= 2 * IPV02D                                       $ CV897B + CV838B
CV897C= 2 * IPV02D                                       $ CV897C + CV838C
CV897D= 2 * IPV02D                                       $ CV897D + CV838D
MV746F= 2 * IPV01T * T1                                  $ MOV746 (opened in injection phase) + HCV640 (HX discharge)
MV747F= 2 * IPV01T * T1                                  $ MOV747 (opened in injection phase) + HCV638 (HX discharge)
MV746D= IPV04D + IPV01T * T1                             $ MOV746 (not yet opened) + HCV640 (HX discharge)
MV747D= IPV04D + IPV01T * T1                             $ MOV747 (not yet opened) + HCV638 (HX discharge)
MV745A= 2 * IPV01T * T3                                  $ MOV745A + MOV745B (crosstie between the HX's)
MV822A= IPV04D + 2 * IPV01T * T4                         $ MOV822A + valves 818A and 820A (CCW to the HX's)
MV822B= IPV04D + 2 * IPV01T * T4                         $ MOV822B + valves 818B AND 820B (CCW to the HX's)
MV851A= IPV02D + IPV01T                                  $ MOV851A + CV858A (common discharge header from SI pumps)
MV851B= IPV02D + IPV01T                                  $ MOV851B + CV858B (common discharge header from SI pumps)
MV856B= IPV04D                                           $ MOV856B (hot leg discharge)
MV856F= IPV04D                                           $ MOV856F (hot leg discharge)
MV856A= 3 * IPV02D + IPV01T * T1                         $ MOV856A + CV857E + CV857J + CV897A (cold leg discharge)
MV856C= 2 * IPV02D + IPV01T * T1                         $ MOV856C + CV857G + CV857C (cold leg discharge)
MV856D= 2 * IPV02D + IPV01T * T1                         $ MOV856D + CV857H + CV857D (cold leg discharge)
MV856E= 3 * IPV02D + IPV01T * T1                         $ MOV856E + CV857L + CV857K + CV897D (cold leg discharge)
MV885A= IPV04D                                           $ MOV885A (intake from containment sump to RHR pumps)
MV885B= IPV04D                                           $ MOV885B (intake from containment sump to RHR pumps)
MV888A= IPV04D                                           $ MOV888A (discharge from HX's to SI pumps)
MV888B= IPV04D                                           $ MOV888B (discharge from HX's to SI pumps)
MV889A= IPV04D                                           $ MOV889A (discharge from HX's to containment spray)
MV889B= IPV04D                                           $ MOV889B (discharge from HX's to containment spray)
M1802A= IPV04D                                           $ MOV1802A (discharge from recirc. pumps to HX's)
M1802B= IPV04D                                           $ MOV1802B (discharge from recirc. pumps to HX's)
MOV730= IPV04D + IPV01T * T1                             $ Leg suction MOV 730 fails to open for RHR
MOV731= IPV04D + IPV01T * T1                             $ Hot Leg suction MOV 731 fails to open for RHR
MOV746= IPV04D + IPV01T * T1                             $ MOV 747 fails to open for RHR
MOV747= IPV04D + IPV01T * T1                             $ MOV 747 fails to open for RHR
MV745B= IPV04D                                           $
RHRVLS= IPV04D + IPV02D                                  $ MOV744 (reopen) + CV741 (discharge from RHR pumps to HX's)
PIPE_F= IPPP2R * T2                                      $ Failure Pipe 60
MN_RHR= IPPF04 * IPPD04                                  $ Maintenance unavailability - RHR pump
MN_SIP= IPPF03 * IPPD03                                  $ Maintenance unavailability - SI pump
MN_ABP= IPPF06 * IPPD06                                  $ Maintenance unavailability - Auxiliary CCW pump
T1    = 24.0                                             $ Mission time
T2    = 168.0                                            $ One-week exposure interval for pipe failure
T3    = 2190 / 2                                         $ Quarterly test interval
T4    = 8760 * 1.5 /2                                    $ Refueling interval
```

TABLE 3.2-14a

SAS SPLIT FRACTIONS

Split Fraction	Definition
EA1	SAS - Train A - safety injection.
EAA	SAS - Train A - safety injection single train.
EA3	SAS - Train A - non-SI events (0.0).
EAF	Guaranteed failure of train A.
EB1	SAS - Train B - safety injection.
EBA	SAS - Train B - safety injection single train.
EBC	Train B failure after train A fails (SI).
EB3	SAS - Train B - non-SI events (0.0).
EBF	Guaranteed failure of train B.

TABLE 3.2-14b

SAS CAUSE TABLE
(continued)

EA1	**SAS - train A - safety injection**
8.656E-03	SAS - train A - safety injection
1.715E-03	Single Safety Injection Logic Channel
3.516E-16	Instrument Loop Failures
6.934E-03	Test contribution - monthly logic test
2.667E-07	Miscalibration error
6.604E-06	Common cause contribution
EAA	**SAS - train A - safety injection single train.**
8.656E-03	SAS - train A - safety injection single train.
1.715E-03	Single Safety Injection Logic Channel
3.516E-16	Instrument Loop Failures
6.934E-03	Test contribution - monthly logic test
2.667E-07	Miscalibration error
6.604E-06	Common cause contribution
EA3	**SAS - train A - non SI events**
0.000E 00	SAS - train A - non SI events
EAF	**Guaranteed failure of train A**
1.000E 00	Guaranteed failure of train A
EB1	**SAS - train B - safety injection**
8.699E-03	SAS - train B - safety injection
EBA	**SAS - train B - safety injection single train**
8.656E-03	SAS - train B - safety injection single train
EBC	**SAS - train B failure after train A fails (SI)**
3.648E-03	SAS - train B failure after train A fails (SI)
EB3	**SAS - train B - non SI events**
0.000E 00	SAS - train B - non SI events
EBF	**Guaranteed failure of train B**
1.000E 00	Guaranteed failure of train B

TABLE 3.2-14(c)
SAS EQUATON FILE

```
EA1      1        EA1TOP= TRAIN                                   $ SAS - train A - safety injection
EAA      1        EAATOP= TRAIN                                   $ SAS-train A - Safety Injection - Signal train
EA3      1        EA3TOP= 0.00                                    $ SAS-train A - non SI events
EAF      1        EAFTOP= 1.00                                    $ Guaranteed fail of train A.
EB1      1        EB1TOP= (TRAIN - SYS) / (1 -TRAIN)              $ SAS - train B - safety injection
EBA      1        EBATOP= TRAIN                                   $ SAS-train B-SI injection single train
EBC      1        EBCTOP= SYS / TRAIN                             $ SAS-trainn B given train A failed (SI)
EB3      1        EB3TOP= 0.00                                    $ SAS - train B -non SI events
EBF      1        EBFTOP= 1.00                                    $ Guaranteed failure train B.
                  SYS    = CHAN2+INST+TEST2+MISCAL+CCSI           $ SI System Total
                  TRAIN  = CHAN1+INST+TEST1+MISCAL+CCSI           $ SI Act Signal - single signal
                  TEST2  = 2 * TEST1 * CHAN1                      $  Hardware failure during test other train
                  CHAN2  = CHAN1 * CHAN1                          $  Two SI Logic Channels
                  CCSI   = CCMR + CCAR + CCBIS + CCLGC            $  Total CCF - SI
                  CCMR   = IPRB1D * MASREL                        $  CCF Master Relays
                  CCAR   = 100/19*IPRB1D*(1-IPGR1D)*AUXREL+X      $ CCF Aux Rlys - SI
                  X      = IPRB1D*IPGR1D*AUXREL                   $
                  CCBIS  = CCPBIS*CCCBIS+XY1                      $
                  XY1    = CCPBIS*3*PZRXTR*PZRXTR+XX1             $  Bistable CCF
                  XX1    = CCCBIS * 3 * CPXMTR * CPXMTR           $
                  CCLGC  = CCGREL*CCGREL+Z1                       $  CCF logic relays fail - both trains
                  Z1     = CCGREL*3*PZRXTR*PZRXTR+XX2             $
                  XX2    = CCGREL * 3 * CPXMTR * CPXMTR           $
                  CHAN1  = 2*(RELS+FUSE)+ZZ1                      $
                  ZZ1    = MASREL+10*AUXREL+Z2                    $ Single SI Act Logic Chnl
                  Z2     = LOGIC1+RSPBS                           $
                  LOGIC1= 3*(LGCREL*LGCREL+CC2REL)*3*Z3           $  Single trn Logic relays fails
                  Z3     = (LGCREL*LGCREL+CC2REL)                 $
                  INST   = 9*CPXMTR*CPXMTR*PZRXTR*PZRXTR          $  Instrument Loop Failures
                  CCPBIS= IPBSWD * IPSW2D                         $ CCF Prez bistables > 2 of 3
                  CCCBIS= IPBSWD * IPSW2D                         $ CCF cont bistables > 2 of 3
                  CC2REL= 1/5 * IPBTRD * (1 - IPGTRD) * IPTR1D    $  CCF logic relays -  2 of 6
                  CCGREL= IPBTRD * IPGTRD * IPTR1D                $  CCF logic relays - global(6)
                  MISCAL= (PZRXTR+BISREL)*(PZRXTR+BISREL)         $  Miscalibration error
                  BISREL= IPTR1D + IPSW2D * T2                    $
                  MASREL= IPRO1D                                  $  Master relay
                  AUXREL= IPRO1D                                  $  Auxiliary relay
                  FUSE   = IPFUSO * T4                            $  Fuse
                  TEST1  = IPRT01/720                             $  Unavail due to monthly test
                  PZRXTR= IPTO2F * T4 + IPSW2D                    $  Pressurzzer transmitter
                  LGCREL= IPTR1D                                  $  Bistable relay
                  CPXMTR= IPTO2F * T4 + IPSW2D                    $  Cont pressure transmitter
                  RELS   = IPSW3S * T2                            $  Short relay contacts
                  RSPBS  = IPSW3S * T2                            $ Short across reset button
                  T2     = 720 / 2                                $  One half of monthly interval
                  T4     = 4.0                                    $  Time to detect fuse failure
```

TABLE 3.2-15a

SWS SPLIT FRACTIONS

Split Fraction	Definition
SA5	Essential SW, two pumps required - All power available.
SA6	Essential SW, two pumps required - Loss of one bus
SAF	Essential SW, two pumps reqd - Guaranteed failure (loss of two buses)
SC5	Essential SW, one pump required - All power available,
SC6	Essential SW, one pump required - Loss of one bus
SCA	Essential SW, one pump required - Loss of power to two buses,
SCF	Essential SW, one pump reqd - Guaranteed failure (loss of all power)
SB5	Non-Essential SWS, All 480V AC buses available,
SB6	Non-Essential SWS, Loss of power to one bus
SBA	Non-Essential SWS, Loss of power to two bus
SBF	Non-Essential SWS, Guaranteed failure (loss of two buses)
SEF	Essential SW, AC Power Recovery - 3 buses initially available (all SWS Pumps initially challenged)
SEA	Essential SW, AC Power Recovery - no power initially available (no SWS Pumps initially challenged)
SE2	Essential SW, AC Power Recovery - initial loss of two buses (one SWS pump initially challenged)
SE1	Essential SW, AC Power Recovery - initial loss of 1 bus, (two SWS Pumps initially challenged)
SNF	Non-Essential SW, AC Power Recovery - 3 buses initially available (all SWS Pumps initially challenged)
SNA	Non-Essential SW, AC Power Recovery - no power initially available (no SWS Pumps initially challenged)
SN2	Non-Essential SWS AC Power Recovery - initial loss of 2 buses (one SWS Pump initially challenged)
SN1	Non-Essential SWS AC Power Recovery - initial loss of 1 bus (two SWS Pumps initially challenged)

TABLE 3.2-15b

SWS CAUSE TABLE

SA5	SWS - essential header - All power available/Two Pumps Reqd
2.609E-04	SWS - essential header - R/S, R/S, S
4.282E-05	Hardware
4.516E-07	Intake and piping failure
4.237E-05	Total pump contribution
1.455E-05	Single pump
5.611E-06	Test unavailability
5.141E-05	Human error - essential header
5.033E-05	Mispositioned service water selector switch
1.084E-06	Misaligned service water pumps
6.442E-05	Common Cause - pumps
9.666E-05	Maintenance Unavailability
SA6	SWS - essential header - Loss of Power to One Bus/Two Pumps Reqd
1.669E-02	SWS - essential header - R/S, R/S, F.
7.296E-03	Hardware
4.516E-07	Intake and piping failure
7.296E-03	Pump contribution
5.112E-04	Test unavailability
5.033E-05	Human error - essential header
5.033E-05	Mispositioned service water selector switch
0.000E 00	Misaligned service water pumps
8.833E-03	Maintenance Unavaiability
SAF	Guaranteed failure of the essential header.
1.000E 00	Guaranteed failure of the essential header.

TABLE 3.2-15b

SWS CAUSE TABLE
(continued)

SC5	**SWS - essential header - All power available/One Pump Reqd**
5.800E-05	SWS - essential header - R/S, R/S, S.
1.157E-06	Hardware
4.516E-07	Intake and piping failure
7.051E-07	Pump contribution
6.496E-07	Test unavailability
1.073E-08	Human error - essential header
5.033E-05	Mispositioned service water selector switch
5.033E-05	Misaligned service water pumps
2.039E-09	Misaligned Service Water Pumps
6.313E-06	Common Cause pumps
SC6	**SWS - essential header - Power lost to one bus/One Pump Reqd**
1.229E-04	SWS - essential header - R/S, R/S, F.
1.485E-05	Hardware
4.516E-07	Intake and piping failure
1.440E-05	Pump contribution
0.000E 00	Test unavailability
5.033E-05	Human error - essential header
5.033E-05	Mispositioned service water selector switch
0.000E 00	Misaligned service water pumps
3.223E-05	Common Cause -pumps
SCA	**SWS - essential header - Power lost to two buses/One Pump Reqd**
8.182E-03	SWS - essential header - R/S, F, F.
3.715E-03	Hardware
4.516E-07	Intake and piping failure
3.714E-03	Pump contribution
0.000E 00	Test unavailability
5.033E-05	Human error - essential header
5.033E-05	Mispositioned service water selector switch
0.000E 00	Misaligned service water pumps
0.000E 00	Common cause - pumps
4.417E-03	Essential Service Water Maintenance

TABLE 3.2-15b

SWS CAUSE TABLE
(continued)

SCF	Guaranteed Failure
1.000E 00	Guaranteed Failure
SB5	SWS - Non-essential header - All Power Available
9.160E-06	SB5 - Non-essential header - R/S, R/S, S.
1.071E-06	Hardware
3.657E-07	Intake and piping failure
7.052E-07	Pump contribution
6.497E-07	Pump contribution
1.355E-06	Maintenance
4.516E-07	Maintenance pump 24
4.516E-07	Maintenance pump 25
4.521E-07	Maintenance pump 26
1.073E-08	Test unavailability
2.039E-09	Misaligned service water pumps
6.721E-06	Common Cause
SB6	SWS - nonessential header - Power lost to one bus
2.866E-04	SWS - nonessential header - R/S, R/S, F
1.476E-05	Hardware
3.657E-07	Intake and piping failure
1.440E-05	Pump contribution
2.441E-04	Maintenance
1.870E-06	Test unavailability
3.614E-07	Misaligned service water pumps
2.552E-05	Common cause - pumps

TABLE 3.2-15b

SWS CAUSE TABLE
(continued)

SBA	SWS - nonessential header - Power lost to two buses
8.437E-03	SWS - nonessential header - R/S, F, F.
3.715E-03	Hardware
3.657E-07	Intake and piping failure
3.714E-03	Pump contribution
4.417E-03	Maintenance
2.556E-04	Test unavailability
5.033E-05	Misaligned service water pumps
0.000E 00	Common cause -pumps
SBF	Guaranteed failure of the nonessential header.
1.000E 00	Guaranteed failure of the nonessential header.
SEA	Essential SW AC Power Recovery - Initial Loss of all power
5.791E-05	Essential SW AC Power Recovery - Initial Loss of all power (No SWS Pumps previously challenged)
SE1	Essential SW AC Power Recovery - Initial Loss of One Bus
3.197E-01	Essential SW AC Power Recovery - Initial Loss of One Bus (Two SWS Pumps previously challenged)
SE2	Essential SW AC Power Recovery - Initial loss of two buses
7.441E-03	Essential SW AC Power Recovery - Initial loss of two buses (One SWS Pump previously challenged)
SEF	Essential SW AC Power Recovery - All Buses Initially Available
1.000E 00	Essential SW AC Power Recovery - All Buses Initially Available (Three SWS Pumps previously challenged)

TABLE 3.2-15b

SWS CAUSE TABLE
(continued)

SNA	Non Essential SW AC Power Recovery - Initial Loss of all power
9.160E-06	Non Essential SW AC Power Recovery - Initial Loss of all power (No SWS Pumps previously challenged)
SN1	Non Essential SW AC Power Recovery - Initial Loss of one bus
5.828E-02	Non Essential SW AC Power Recovery - Initial Loss of one bus (Two SWS Pumps previously challenged)
SE2	Non Essential SW AC Power Recovery - Initial loss of two buses
1.118E-03	Non Essential SW AC Power Recovery - Initial loss of two buses (One SWS Pump previously challenged)
SNF	Non Essential SW AC Power Recovery - All Buses Initially Available
1.000E 00	Non Essential SW AC Power Recovery - All Buses Initially Available (Three SWS Pumps previously challenged)

TABLE 3.2-15(c)
SWS EQUATION FILE

```
SA5   1 SA5TOP= SWN5_H + SWN5_T + SWN5_O +SWN5_C + SWN5_M        $ Essential SW - two pmps required - All power available
SA5   2 SWN5_H= INTAKE + SWPUMP                                  $ Hardware
SA5   3 INTAKE= SCREEN * GATE1 * GATE2 + PIPE_N                  $  Intake and piping failure
SA5   4 SWPUMP= PMP21S * PMP22S + PMP21S * PMP23S + SWPMP5       $  Pump contribution
SA5   5 SWPMP5= PMP22S*PMP23S+Z1                                 $
SA5     Z1    = PMPCVR*(PMP21S+PMP22S+PMP23R)                    $
SA5   6 SWN5_T= 3 * TEST_U * (PMP21S + PMP22S)                   $ Test unavailability
SA5   7 SWN5_O= SWNOP1 + SWNOP2                                  $ Human error - Nuclear header
SA5   8 SWNOP1= HEMPSW                                           $  Mispositioned service water selector switch
SA5   9 SWNOP2= 3 * HENHPT * (PMP21S + PMP22S)                   $  Misaligned service water pumps
SA5  10 SWN5_C= IPB07S*(3/2*(1-IPG07S)+IPG07S)*IPP07S+SWN_C1     $ Common cause pumps
SA5  11 SWN_C1= IPB07R*(3/2*(1-IPG07R)+IPG07R)*IPP07R*T1         $
SA5  12 SWN5_M= 3 * ESWMNT * (PMP22S + PMP23S)                   $   Maintenance Unavailability
SA6   1 SA6TOP= SWN6_H + SWN6_T + SWN6_O + SWN6_M                $ Essential SW, two pumps required  - Loss of one bus
SA6   2 SWN6_H= INTAKE + SWPUMP                                  $ Hardware
SA6   3 INTAKE= SCREEN * GATE1 * GATE2 + PIPE_N                  $  Intake and piping failure
SA6   4 SWPUMP= PMP21S + PMP22S                                  $  Pump contribution
SA6   5 SWN6_T= 2 * TEST_U                                       $ Test unavailability
SA6   6 SWN6_O= SWNOP1 + SWNOP2                                  $ Human error - Nuclear header
SA6   7 SWNOP1= HEMPSW                                           $  Mispositioned service water selector switch
SA6   8 SWNOP2= 0.00                                             $  Misaligned service water pumps
SA6   9 SWN6_M= 2 * ESWMNT                                       $  Maintenance Unavailability
SAF   1 SAFTOP= 1.00                                             $ Essential SW, two pumps required - Guaranteed failure (loss of two
                                                                              buses)

SC5   1 SC5TOP= SWN5_H+SWN5_T+SWN5_O+SWN5_C+SWN5_M               $ Essential SW, one pump required - All power available
SC5   2 SWN5_H= INTAKE + SWPUMP                                  $ Hardware
SC5   3 INTAKE= SCREEN * GATE1 * GATE2 + PIPE_N                  $  Intake and piping failure
SC5   4 SWPUMP= PMP21S * PMP22S * PMP23S + SWPMP5                $  Pump contribution
SC5   5 SWPMP5= PMPCVR * (PMP21S + PMP22S + PMP23R)              $
SC5   6 SWN5_T= 3 * TEST_U * (PMP21S * PMP22S )                  $ Test unavailability
SC5   7 SWN5_O= SWNOP1 + SWNOP2                                  $ Human error - Nuclear header
SC5   8 SWNOP1= HEMPSW                                           $  Mispositioned service water selector switch
SC5   9 SWNOP2= 3 * HENHPT * (PMP21S * PMP22S )                  $  Misaligned service water pumps
SC5  10 SWN5_C= IPB07S*IPP07S*Z2+SWN_C2                          $
SC5     Z2    = (IPG07S+3/2*(1-IPG07S)*SWN_C1)                   $ CCF-Pumps
SC5  11 SWN_C2= IPB07R*SWN_C6*Z3+SWN_C3                          $
SC5     Z3    = (IPG07R+3/2*(1-IPG07R)*SWN_C1)                   $
SC5  12 SWN_C1= TEST_U + HENHPT                                  $
SC5  13 SWN_C3= (SWN_C4+SWN_C5)*(PMP21S+PMP22S+PMP23S)           $
SC5  14 SWN_C4= 1/2*IPB07S*IPP07S*(1-IPG07S)                     $
SC5  15 SWN_C5= 1/2*IPB07R*SWN_C6*(1-IPG07R)                     $
SC5  16 SWN_C6= IPP07R*T1                                        $
SC5  17 SWN5_M= 3 * ESWMNT * (PMP22S * PMP23S)                   $  Maintenance Unavailability
```

TABLE 3.2-15(c)
SWS EQUATION FILE

```
SC6   1 SC6TOP= SWN6_H+SWN6_T+SWN6_O+SWN6_C+SWN6_M            $ Essential SW, one pump required - Loss of one bus
SC6   2 SWN6_H= INTAKE + SWPUMP                               $  Hardware
SC6   3 INTAKE= SCREEN * GATE1 * GATE2 + PIPE_N               $   Intake and piping failure
SC6   4 SWPUMP= PMP21S * PMP22S + PMPCVR * (PMP21S + PMP22S)  $   Pump contribution
SC6   5 SWN6_T= 0.00                                          $  Test unavailability
SC6   6 SWN6_O= SWNOP1 + SWNOP2                               $  Human error - Nuclear header
SC6   7 SWNOP1= HEMPSW                                        $   Mispositioned service water selector switch
SC6   8 SWNOP2= 0.00                                          $   Misaligned service water pumps
SC6   9 SWN6_M= 2 * ESWMNT * PMP22S                           $
SC6  10 SWN6_C= IPB07S*(1/2*(1-IPG07S)+IPG07S)*IPP07S + SWN_C1 $ Common Cause
SC6  11 SWN_C1= IPB07R*(1/2*(1-IPG07R)+IPG07R)*IPP07R*T1      $
SCA   1 SCATOP= SWNA_H + SWNA_T + SWNA_O+SWNA_C+SWNA_M        $ Essential SW, one pump required - Loss of power to two buses
SCA   2 SWNA_H= INTAKE + SWPUMP                               $  Hardware
SCA   3 INTAKE= SCREEN * GATE1 * GATE2 + PIPE_N               $   Intake and piping failure
SCA   4 SWPUMP= PMP21S + PMPCVR                               $   Pump contribution
SCA   5 SWNA_T= 0.00                                          $  Test unavailability
SCA   6 SWNA_O= SWNOP1 + SWNOP2                               $  Human error - Nuclear header
SCA   7 SWNOP1= HEMPSW                                        $  Mispositioned service water selector switch
SCA   8 SWNOP2= 0.00                                          $   Misaligned service water pumps
SCA   9 SWNA_C= 0.00                                          $
SCA  10 SWNA_M= ESWMNT                                        $   Maintenance unavailability
SCF   1 SCFTOP= 1.0                                           $ Essential SW, one pump required - Guarenteed failure (loss of two
                                                                     buses)
SB5   1 SB5TOP= SWC5_H + SWC5_M + SWC5_T+SWC5_O+SWC5_C        $ Non-Essential header - All 480V AC Power available.
SB5   2 SWC5_H= INTAKE + SWPUMP                               $  Hardware
SB5   3 INTAKE= SCREEN * GATE1 * GATE2 + PIPE_C               $   Intake and piping failure
SB5   4 SWPUMP= PMP24S * PMP25S * PMP26S + SWPMP1             $   Pump contribution
SB5   5 SWPMP1= PMPCVR * (PMP24S + PMP25S + PMP26R)           $
SB5   6 SWC5_M= PMP24M + PMP25M + PMP26M                      $  Maintenance
SB5   7 PMP24M= SWPMNT*(PM25SM*PMP26S+Z4)                     $
SB5     Z5    = PMPCVR*(PMP25S+PMP26R)                        $   Maintenance pump 24
SB5   8 PMP25M= SWPMNT*(PM24SM*PMP26S+Z6)                     $
SB5     Z6    = PMPCVR*(PMP24S+PMP26R)                        $   Maintenance pump 25
SB5   9 PMP26M= SWPMNT*(PM24SM*PMP25S+Z7                      $
SB5     Z7    = PMPCVR*(PMP24S+PMP25S))                       $   Maintenance pump 26
SB5  10 SWC5_T= 3 * TEST_U * (PMP24S * PMP25S )               $  Test unavailability
SB5  11 SWC5_O= 3 * HENHPT * (PMP24S * PMP25S )               $  Misaligned service water pumps
SB5  12 SWC5_C= IPB07S*IPP07S*Z8 + SWC_C2                     $
SB5     Z8    = (IPG07S+3/2*(1-IPG07S)*SWC_C1)                $ Common Cause -pumps
SB5  13 SWC_C2= IPB07R*SWC_C6*Z9+SWC_C                        $
SB5     Z9    = (IPG07R+3/2*(1-IPG07R)*SWC_C1)                $
SB5  14 SWC_C1= TEST_U + HENHPT + SWPMNT                      $
SB5  15 SWC_C3= (SWC_C4+SWC_C5)*(PMP24S+PMP25S+PMP26S)        $
SB5  16 SWC_C4= 1/2*IPB07S*(1-IPG07S)*IPP07S                  $
SB5  17 SWC_C5= 1/2*IPB07R*(1-IPG07R)*SWC_C6                  $
SB5  18 SWC_C6= IPP07R*T1                                     $
```

TABLE 3.2-15(c)
SWS EQUATION FILE

```
SB6   1 SB6TOP= SWC6_H + SWC6_M + SWC6_T+SWC6_O+SWC6_C          $ SB6 - Non-Essential SW - Loss of one bus
SB6   2 SWC6_H= INTAKE + SWPUMP                                 $  Hardware
SB6   3 INTAKE= SCREEN * GATE1 * GATE2 + PIPE_C                 $   Intake and piping failure
SB6   4 SWPUMP= PMP24S*PMP25S+PMPCVR*(PMP24S+PMP25S)            $   Pump contribution
SB6   5 SWC6_M= 2 * SWPMNT * PM24SM                             $  Maintenance
SB6   6 SWC6_T= 2 * TEST_U * PMP24S                             $  Test unavailability
SB6   7 SWC6_O= 2 * HENHPT * PMP24S                             $  Misaligned service water pumps
SB6   8 SWC6_C= IPB07S*(1/2*(1-IPG07S)+IPG07S)*IPP07S + SWC_C1  $  Common Cause
SB6   9 SWC_C1= IPB07R*(1/2*(1-IPG07R)+IPG07R)*IPP07R * T1      $
SBA   1 SBATOP= SWCA_H + SWCA_M + SWCA_T +SWCA_O+SWCA_C         $ SBA - Non-Essential SW  - Loss of two buses.
SBA   2 SWCA_H= INTAKE + SWPUMP                                 $  Hardware
SBA   3 INTAKE= SCREEN * GATE1 * GATE2 + PIPE_C                 $   Intake and piping failure
SBA   4 SWPUMP= PMP24S + PMPCVR                                 $   Pump contribution
SBA   5 SWCA_M= ESWMNT                                          $  Maintenance
SBA   6 SWCA_T= TEST_U                                          $  Test unavailability
SBA   7 SWCA_O= HENHPT                                          $  Misaligned service water pumps
SBA   8 SWCA_C= 0.00                                            $  Common Cause
SBF   1 SBFTOP= 1.00                                            $ Guaranteed failure of the Non-Essential header.
SEA   1 SEATOP= SEATOP                                          $ Essential SW, AC Power Recovery - no power initally available
                                                                        (no SWS Pumps initially challenged)
SE1   1 SE1    = SEATOP/SE1TOP                                  $ Essential SW, AC Power Recovery - Initial loss of one bus
SE2   1 SE2    = SEATOP/SE2TOP                                  $ Essential SW, AC Power Recovery - Initial loss of two buses
                                                                        (one SW pump initially challenged)
SEF   1 SEF    = SEATOP/SEATOP                                  $ Essential SW, AC Power Recovery - three buses initially available
                                                                        (all SW pumps initially challenged)
SNA   1 SNA    = SNATOP                                         $ Non-Essential SW, AC Power Recovery - no power initially available
                                                                        (no SW pumps initially challenged)
SN1   1 SN1    = SNATOP/SN1TOP                                  $ Non-Essential SW, AC Power Recovery - initial loss of two buses
                                                                        (two SW Pumps initially challenged)
SN2   1 SN2    = SNATOP/SN2TOP                                  $ Non-Essential SW, AC Power Recovery - initial loss of two buses
                                                                        (one SW pump initially challenged)
SNF   1 SNF    = SNATOP/SNATOP                                  $ Non-Essential SW, AC Power Recovery -  three buses initially
                                                                        available (all SW Pumps initially challenged)
        SEATOP= SEN5_H + SEN5_T+SEN5_O+SEN5_C+SEN5_M            $ SC5 - (SC) essential header - All power available
        SEN5_H= INTAKE + SEAUMP                                 $  Hardware
        SEAUMP= PMP21S * PMP22S * PMP23S + SEPMP5               $   Pump contribution
        SEPMP5= PMPCVR * (PMP21S + PMP22S + PMP23R)             $
        SEN5_T= 3 * TEST_U * (PMP21S * PMP22S )                 $  Test unavailability
        SEN5_O= SENOP1 + SENOP2                                 $  Human error - Nuclear header
        SENOP1= HEMPSW                                          $   Mispositioned service water selector switch
        SENOP2= 3 * HENHPT * (PMP21S * PMP22S )                 $   Misaligned service water pumps
        SEN5_C= IPB07S*IPP07S*Z10 + SEN_C2                      $
        Z10   = (IPG07S+3/2*(1-IPG07S)*SEN_C1)                  $ Common Cause -Pumps
        SEN_C2= IPB07R*SEN_C6*Z11+SEN_C3                        $
        Z11   = (IPG07R+3/2*(1-IPG07R)*SEN_C1)                  $
        SEN_C1= TEST_U + HENHPT                                 $
        SEN_C3= (SEN_C4+SEN_C5)*(PMP21S+PMP22S+PMP23S)          $
        SEN_C4= 1/2*IPB07S*IPP07S*(1-IPG07S)                    $
        SEN_C5= 1/2*IPB07R*SEN_C6*(1-IPG07R)                    $
```

TABLE 3.2-15(c)
SWS EQUATION FILE

```
SEN_C6= IPP07R*T1                                              $
SEN5_M= 3 * ESWMNT * (PMP22S * PMP23S)                         $   Maintenance Unavailability
SE1TOP= SEN6_H + SEN6_T + SEN6_O + SEN6_C + SEN6_M             $  SC6 - (SC) essential header - R/S, R/S, F.
SEN6_H= INTAKE + SE1UMP                                        $  Hardware
SE1UMP= PMP21S * PMP22S + PMPCVR * (PMP21S + PMP22S)           $    Pump contribution
SEN6_T= 0.00                                                   $  Test unavailability
SEN6_O= SENOP1 + SENOP2                                        $  Human error - Nuclear header
SENOP1= HEMPSW                                                 $   Mispositioned service water selector switch
SENOP2= 0.00                                                   $   Misaligned service water pumps
SEN6_M= 2 * ESWMNT * PMP22S                                    $
SEN6_C= IPB07S*(1/2*(1-IPG07S)+IPG07S)*IPP07S + SEN_C1         $ Common Cause
SEN_C1= IPB07R*(1/2*(1-IPG07R)+IPG07R)*IPP07R*T1               $
SE2TOP= SENA_H + SENA_T + SENA_O + SENA_C + SENA_M             $ SCA - (SC) essential header - R/S, F, F.
SENA_H= INTAKE + SE3UMP                                        $  Hardware
SE3UMP= PMP21S + PMPCVR                                        $   Pump contribution
SENA_T= 0.00                                                   $  Test unavailability
SENA_O= SENOP1 + SENOP2                                        $  Human error - Nuclear header
SENOP1= HEMPSW                                                 $   Mispositioned service water selector switch
SENOP2= 0.00                                                   $   Misaligned service water pumps
SENA_C= 0.00                                                   $
SENA_M= ESWMNT                                                 $   Maintenance unavailability
SNATOP= SNC5_H + SNC5_M + SNC5_T + SNC5_O + SNC5_C             $ SB5 - Non-Essential header - R/S, R/S, S .
SNC5_H= INTAKE + SNAUMP                                        $  Hardware
SNAUMP= PMP24S * PMP25S * PMP26S + SNPMP1                      $   Pump contribution
SNPMP1= PMPCVR * (PMP24S + PMP25S + PMP26R)                    $
SNC5_M= PMP24M + PMP25M + PMP26M                               $  Maintenance
PMP24M= SWPMNT*(PM25SM*PMP26S+Z12                              $
Z12   = PMPCVR*(PMP25S+PMP26R))                                $   Maintenance pump 24
PMP25M= SWPMNT*(PM24SM*PMP26S+Z13                              $
Z13   = PMPCVR*(PMP24S+PMP26R))                                $   Maintenance pump 25
PMP26M= SWPMNT*(PM24SM*PMP25S+Z14                              $
Z14   = PMPCVR*(PMP24S+PMP25S))                                $   Maintenance pump 26
SNC5_T= 3 * TEST_U * (PMP24S * PMP25S)                         $  Test unavailability
SNC5_O= 3 * HENHPT * (PMP24S * PMP25S )                        $  Misaligned service water pumps
SNC5_C= IPB07S*IPP07S*Z15 + SNC_C2                             $
Z15   = (IPG07S+3/2*(1-IPG07S)*SNC_C1)                         $ Common Cause pumps
SNC_C2= IPB07R*SNC_C6*Z16+SNC_C3                               $
Z16   = (IPG07R+3/2*(1-IPG07R)*SNC_C1)                         $
SNC_C1= TEST_U + HENHPT + SWPMNT                               $
SNC_C3= (SNC_C4+SNC_C5)*(PMP24S+PMP25S+PMP26S)                 $
SNC_C4= 1/2*IPB07S*(1-IPG07S)*IPP07S                           $
SNC_C5= 1/2*IPB07R*(1-IPG07R)*SNC_C6                           $
SNC_C6= IPP07R*T1                                              $
SN1TOP= SNC6_H+SNC6_M+SNC6_T+SNC6_O+SNC6_C                     $ SB6 - Non-Essential header - Loss of 1 bus 5A, 6A or 2A.
```

TABLE 3.2-15(c)
SWS EQUATION FILE

```
SNC6_H= INTAKE + SN1UMP                                     $ Hardware
SN1UMP= PMP24S * PMP25S + PMPCVR * (PMP24S + PMP25S)        $  Pump contribution
SNC6_M= 2 * SWPMNT * PM24SM                                 $ Maintenance
SNC6_T= 2 * TEST_U * PMP24S                                 $ Test unavailability
SNC6_O= 2 * HENHPT * PMP24S                                 $ Misaligned service water pump s
SNC6_C= IPB07S*(1/2*(1-IPG07S)+IPG07S)*IPP07S + SNC_C1      $ Common Cause
SNC_C1= IPB07R*(1/2*(1-IPG07R)+IPG07R)*IPP07R * T1          $
SN2TOP= SNCA_H + SNCA_M + SNCA_T + SNCA_O + SNCA_C          $ SBA - Non-Essential header - Loss of two buses.
SNCA_H= INTAKE + SN2UMP                                     $ Hardware
INTAKE= SCREEN * GATE1 * GATE2 + PIPE_C                     $  Intake and piping failure
SN2UMP= PMP24S + PMPCVR                                     $  Pump contribution
SNCA_M= ESWMNT                                              $ Maintenance
SNCA_T= TEST_U                                              $ Test unavailability
SNCA_O= HENHPT                                              $ Misaligned service water pumps
SNCA_C= 0.00                                                $ Common Cause
PM24SM= PMP21S + P24M24                                     $ Mean maintenance duration for components
                                                                   under a 24 hr Tech Spec.
PM25SM= PMP25S + P25M24                                     $ Mean maintenance duration for components
                                                                   under a 24 hr Tech Spec.
P24M24= IPPF07 * MPD24                                      $  2nd non-essential pump in maintenance
P25M24= IPPF07 * MPD24                                      $  2nd non-essential pump in maintenance
PMP21S= IPP07S + IPV02D + 2*IPV01T * T3 + PMP21R            $ Previously running pump restarts
PMP21R= (IPP07R + IPS01P + 2 * IPV01T) * T1                 $ Normally running service water pump
PMP22S= IPP07S + IPV02D + 2 * IPV01T * T3 + PMP22R          $ Previously running pump restarts
PMP22R= (IPP07R + IPS01P + 2*IPV01T) * T1                   $ Normally running service water pump
```

TABLE 3.2-15(c)
SWS EQUATION FILE

```
PMP23S= IPP07S + IPV02D + 2*IPV01T * T3 + PMP23R     $  Standby pump fail to start
PMP23R= (IPP07R + IPS01P + IPV01T) * T1              $  Normally running service water pump
PMP24S= IPP07S + IPV02D + 2*IPV01T * T3 + PMP24R     $  Previously running pump restarts
PMP24R= (IPP07R + IPS01P + 2*IPV01T) * T1            $  Normally running service water pump
PMP25S= IPP07S + IPV02D + 2*IPV01T * T3 + PMP25R     $  Previously running pump restarts
PMP25R= (IPP07R + IPS01P + 2*IPV01T) * T1            $  Normally running service water pump
PMP26S= IPP07S + IPV02D + 2*IPV01T * T3 + PMP26R     $  Standby pump fail to start
PMP26R= (IPP07R + IPS01P + 2*IPV01T) * T1            $  Normally running service water pump
PMPCVR= IPV02D + IPV12L*T1                           $  Pump discharge check valve - reverse leakage
HEMPSW= HE01A * HE02A                                $  Mispositioned mode selector switch
HENHPT= HE01A * HE02A                                $  Nuclear pump train testing unavailable
SCREEN= IPS01P * T1                                  $        Screen plug
GATE1 = IPV01T * T3                                  $  SW bypass gate 1
GATE2 = 1.0                                          $  SW bypass gate 2
SWPMNT= IPPF07 * IPPD07 * 2                          $  Maintenance unavailability service water pump
ESWMNT= IPPF07 * MPD12                               $
TEST_U= IPPT07/(T3*2)                                $  Test unavailability
PIPE_N= 17 * IPPP2R * T1                             $        SW essential header piping failure
PIPE_C= 13 * IPPP2R * T1                             $  SW non-essential header piping failure
MPD24 = 12                                           $ Mean maintenance duration
MPD12 = 6                                            $ Mean maintenance duration
T1    = 24.0                                         $  Mission time
T3    = 2160 / 2                                     $  The monthly test interval
```

TABLE 3.2-16a

OPR SPLIT FRACTIONS

Split Fraction	Definition
P11	OSP (Grid) Recovery, 0 <= t < 1/2 hr.
P21	OSP (Grid) Recovery, 1/2<= t < 1 hr.
P31	OSP (Grid) Recovery, 1 <= t < 3 hr.
T11	GT Start/load 0 <= t < 1/2 hr, given no SBO
T12	GT Start/load 0 <= t < 1/2 hr, given SBO
T21	GT Start/load 1/2<= t < 1 hr, no SBO
T22	GT Start/load 1/2<= t < 1 hr, SBO
T31	GT Start/load 1/2<= t < 3 hr, no SBO.
T32	GT Start/load 1/2<= t < 3 hr, and SBO
C11	No OSP before Core Cooling Uncovery, 1/2 <= t < 10 hr.
C12	No OSP before Core Cooling Uncovery, 1/2 <= t < 3 hr.
C13	No OSP before Core Cooling Uncovery, 3 <= t < 10 hr.
C21	GT Fails to Start/Load before Core Uncovery (CU), 1/2<= t < 10h, no SI/no SBO and C11=F
C22	GT Fails to Start/Load before CU, 1/2 <= t < 3h, no SI/SBO and C12=F
C25	GT Fails to Start/Load before CU, 1/2 <= t < 3h, SBO/ C1=B
C27	GT Fails to Start/Load before CU, 3 <= t < 10h, SBO/ C13=F
VF1	No AC Recovery between Core Uncovery Due to RCP Seal LOCA & Core Slump given SBO
VF3	No AC Recovery between Core Uncovery (due to loss of AFS at T=3 hours) & Core Slump given SBO
VF5	No AC Recovery between Core Uncovery (due to loss of AFS at T=0 hours) & Core Slump given SBO
VF7	No AC Recovery between Core Uncovery Due to SORV & Core Slump given SBO
VFF	Guaranteed failure of VF
CF1	No OSP,between Core Slump & Containment Failure given VF1 fails
CF3	No OSP,between Core Slump & Containment Failure given VF3 fails
CF5	No OSP,between Core Slump & Containment Failure given VF5 fails
CF7	No OSP,between Core Slump & Containment Failure given VF7 fails
CFF	Guaranteed failure of CF

TABLE 3.2-16b

OPR CAUSE TABLE

P11 OSP (Grid) Recovery, 0 < t < 1/2 hr
9.770E-01 OSP (Grid) Recovery, 0 < t < 1/2 hr
P21 OSP (Grid) Recovery, 1/2 < t < 1 hr
5.200E-01 OSP (Grid) Recovery, 1/2 < t < 1 hr
P31 OSP (Grid) Recovery, 1 < t < 3 hr
1.850E-01 OSP (Grid) Recovery, 1 < t < 3 hr
T11 GT Start/load 0 <= t < 1/2 hr, given no SBO
3.300E-01 GT Start/load 0 <= t < 1/2 hr, given no SBO
T12 GT Start/load 0 <= t < 1/2 hr, given SBO
2.500E-01 GT Start/load 0 <= t < 1/2 hr, given SBO
T21 GT Start/load 1/2 <= t < 1 hr, no SBO
1.610E-01 GT Start/load 1/2 <= t < 1 hr, no SBO
T22 GT Start/load 1/2 <= t < 1 hr, SBO
6.940E-01 GT Start/load 1/2 <= t < 1 hr, SBO
T31 GT Start/load 1/2 <= t < 3 hr, no SBO.
3.270E-01 GT Start/load 1/2 <= t < 3 hr, no SBO.
T32 GT Start/load 1/2 <= t < 3 hr, SBO
4.220E-01 GT Start/load 1/2 <= t < 3 hr, SBO
C11 No OSP before Core Cooling Uncovery, 1/2 <= t < 10 hr.
9.140E-02 No OSP before Core Cooling Uncovery, 1/2 <= t < 10 hr.
C12 No OSP before Core Cooling Uncovery, 1/2 <= t < 3 hr.
6.530E-04 No OSP before Core Cooling Uncovery, 1/2 <= t < 3 hr.

TABLE 3.2-16b

OPR CAUSE TABLE

C13	No OSP before Core Cooling Uncovery, 3 < = t < 10 hr.
3.700E-01	No OSP before Core Cooling Uncovery, 3 < = t < 10 hr.
C21	GT Failed to Start/Load before Core Uncovery (CU), 1/2 < = t < 10hr no SBO and C11=F
8.8901E-02	GT Failed to Start/Load before Core Uncovery (CU), 1/2 < = t < 10hr no SBO and C11=F
C22	GT Fails to Start/Load before CU, 1/2 < =t< 3h, SBO and C12=F
4.400E-01	GT Fails to Start/Load before CU, 1/2< =t<3h, SBO and C12=F
C25	GT Failed to Start/Load before CU, 1/2 < = t < 3h, SBO/ C1=B
1.120E-03	GT Failed to Start/Load before CU, 1/2< =t<3h, SBO/ C1=B
C27	GT Failed to Start/Load before CU, 3 < = t < 10h, SBO/C13=F
1.000E 00	GT Failed to Start/Load before CU, 3 < = t < 10h, SBO/C13=F
VF1	No AC Recovery between Core Uncovery due to Seal LOCA & Core Slump
1.500E-01	No AC Recovery between Core Uncovery due to Seal LOCA & Core Slump
VF3	No AC Recovery between Core Uncovery due to loss of AFS at 3 hrs & Core Slump
5.700E-02	No AC Recovery between Core Uncovery due to loss of AFS at 3 hrs & Core Slump
VF5	No AC Recovery between Core Uncovery due to loss of AFS at T=0 hrs & Core Slump
2.500E-01	No AC Recovery between Core Uncovery due to loss of AFS at T=0 hrs & Core Slump
VF7	No AC Recovery between Core Uncovery due to SORV & Core Slump
3.100E-01	No AC Recovery between Core Uncovery due to SORV & Core Slump
VFF	Guaranteed failure of VF
1.000E 00	Guaranteed failure of VF

TABLE 3.2-16b

OPR CAUSE TABLE
(continued)

CF1	No AC Recovery between Core Slump & Containment Failure given VF1 fails
5.000E-01	No AC Recovery between Core Slump & Containment Failure given VF1 fails
CF3	No AC Recovery between Core Slump & Containment Failure given VF3 fails
5.000E-01	No AC Recovery between Core Slump & Containment Failure given VF3 fails
CF5	No AC Recovery between Core Slump & Containment Failure given VF5 fails
5.000E-01	No AC Recovery between Core Slump & Containment Failure given VF5 fails
CF7	No AC Recovery between Core Slump & Containment Failure given VF7 fails
5.000E-01	No AC Recovery between Core Slump & Containment Failure given VF7 fails
CFF	Guaranteed failure of CF
1.000E 00	Guaranteed failure of CF

TABLE 3.2-16(c)
OPR EQUATION FILE

```
P11    1 P11   = 0.977       $ OSP (Grid) Recovery,  0 < t <  1/2 hr.$
P21    1 P21   = 0.520       $ OSP (Grid) Recovery,1/2 < t < 1 hr.
P31    1 P31   = 0.185       $ OSP (Grid) Recovery,    1  < t < 3 hr.$
T11    1 T11   = 0.330       $ GT Start/Load 0<=t<1/2 hr, given no SBO
T12    1 T12   = 0.250       $ GT Start/Load 0<=t<1/2 hr, given SBO
T21    1 T21   = 0.161       $ GT Start/Load 1/2<=t<1 hr, no SBO
T22    1 T22   = 0.694       $ GT Start/Load 1/2<=t<1 hr.  SBO
T31    1 T31   = 0.327       $ GT Start/Load 1/2<=t<3 hr. no SBO.
T32    1 T32   = 0.422       $ GT Start/Load 1/2<=t<3 hr.  SBO
C11    1 C11   = 9.14E-2     $ no OSP before Core Cooling Uncovery,1/2<=t<10 hrC12
C12    1 C12   = 6.53E-4     $ no OSP before Core Cooling Uncovery, 1/2 <=t<3 hr.
C13    1 C13   = 0.37        $ no OSP before Core Cooling Uncovery, 3 <=t<10 hr.
C21    1 C21   = 8.98E-2     $ GT fails to Start/Load Before Core Uncovery,
                                       .5<=t<10h, no SBO/ C11=F
C22    1 C22   = 0.44        $ GT fails to Start/Load Before Core Uncovery
                                       .5<=t<3h, SBO/ C12=F
C25    1 C25   = 1.12E-3     $ GT fails to Start/Load before Core Cooling,
                                       .5<=t<3h, SBO/ C1=B
C27    1 C27   = 1.0         $ GT fails to Start/Load before Core Cooling 3<=t<10h, SBO/ C13=F
VF1    1 VF1   = .15         $ No AC Recovery, between Core Uncovery
                                    due to Seal LOCA & Core Slump given SBO.
VF3    1 VF3   = .15         $ No AC Recovery, between Core Uncovery
                                    due to loss of AFS at T=3hrs & Core Slump.
VF5    1 VF5   = .25         $ No AC Recovery, between Core Uncovery due to loss of AFS
                                    at t=0hrs & Core Slump.
VF7    1 VF7   = .31         $ No AC Power Recovery  between Core Uncovery due to
                                    Stuck Open Relief Valve and Core Slump.
CF1    1 CF1   = .5          $ No AC Power Recovery, between Core Clump & Containment failure given VF1
CF3    1 CF3   = .5          $ No AC Power Recovery, between Core Clump & Containment failure given VF3
CF5    1 CF5   = .5          $ No AC Power Recovery, between Core Clump & Containment failure given VF5
CF7    1 CF7   = .5          $ No AC Power Recovery, between,Core Clump & Containment failure given VF7
CFF    1 CFF   = 1.0         $ Guarenteed failure ofCF
```

TABLE 3.2-17a

VENT SPLIT FRACTIONS

Split Fraction	Definition
ST1	One EDG running and Bus 3A or 5A lost[1]
ST2	Two EDGs running and Bus 3A and 5A available
ST3	Two EDGs running and Bus 3A or 5A lost
ST4	Three EDGs running and Bus 5A and 3A available
ST5	Three EDGs running and Bus 5A or 3A lost
STF	1, 2 or 3 EDGs running and Bus 5A and 3A lost[2]

Note: (1) With only one EDG running BUS 3A or 5A are cannot be powered.

(2) The ambient temperature required to allow operation of an EDG with no fans operating is such that this condition is assumed to represent guaranteed failure (STF).

TABLE 3.2-17b

VENT CAUSE TABLE

ST1 EDG building ventilation - 1 EDG I/S - buses 5A or 3A lost

2.060E-05	EDG building ventilation - 1 EDG I/S - buses 5A or 3A lost
1.996E-05	One fan required for success
3.212E-07	Hardware failure
1.964E-05	Common Cause failures
0.000E 00	Maintenance
8.381E-05	Two fans required
6.417E-05	Hardware
1.964E-05	Common Cause
0.000E 00	Maintenance

ST2 EDG building ventilation - 2 EDG I/S - buses 5A and 3A available

2.868E-04	EDG building ventilation - 2 EDG I/S - buses 5A and 3A available
1.964E-05	Hardware (One fan required for success).
2.018E-10	Hardware
2.139E-05	Hardware
1.964E-05	Common Cause
0.000E 00	Maintenance
1.968E-05	Two fans required
3.673E-08	Hardware (4 fans fail)
1.964E-05	Common Cause
0.000E 00	Maintenance
2.671E-02	Three fans required
2.670E-02	Hardware
1.964E-05	Common Cause
0.000E 00	Maintenance
1.483E-02	Common Cause

TABLE 3.2-17b

VENT CAUSE TABLE (continued)

ST3	EDG Building Ventilation - 2 EDG. loss of bus 5A or 3A
1.144E-04	EDG Building Ventilation - 2 EDG. loss of bus 5A or 3A
3.212E-07	One fan required
3.212E-07	Hardware
2.578E-12	Common Cause
0.000E 00	Maintenance
8.381E-05	Two fans required
6.417E-05	Hardware
1.964E-05	Common Cause
0.000E 00	Maintenance
8.898E-03	Three Fans required
8.898E-03	Hardware
0.000E 00	Common Cause
0.000E 00	Maintenance
ST4	EDG building vent - 3EDGs and 5A and 3A available
1.970E-05	EDG building vent - 3EDGs and 5A and 3A available
1.964E-05	Hardware (five fans fail)
2.018E-10	Hardware
2.139E-05	Hardware
1.964E-05	Common Cause
0.000E 00	Maintenance
1.968E-05	2 fans required
3.673E-08	Hardware
1.964E-05	Common Cause
0.000E 00	Maintenance
2.061E-05	3 fans required
9.635E-07	Hardware
1.964E-05	Common Cause

TABLE 3.2-17b

VENT CAUSE TABLE
(continued)

ST5	EDG building vent - 3 EDG - Bus 5A or 3A lost
3.593E-03	EDG building vent - 3 EDG - Bus 5A or 3A lost
3.212E-07	1 fan required
3.212E-07	Hardware
2.578E-12	Common Cause
0.000E 00	Maintenance
8.381E-05	2 fans required
6.417E-05	Hardware
1.964E-05	Common Cause
0.000E 00	Maintenance
8.898E-03	3 fans required
8.898E-03	Hardware
0.000E 00	Common Cause
0.000E 00	Maintenance
STF	Guaranteed failure of ST
1.000E 00	Guaranteed failure of ST

TABLE 3.2-17(c)
VENT EQUATION FILE

```
ST1    1 F11TOP= F11_1 * FS11 + F11_2 * FS12                   $ EDG building ventialtion (bus 5A or 6A lost)
ST1    2 F11_1 = F11_1H + F11_1C + F11_1M                      $  One fan requires for success.
ST1    3 F11_1H= FN318 * FN320 * FN322                         $   Hardware failure
ST1    4 F11_1C= CC2FN * (FN318 + FN320 + FN322) + CC3FN       $   Common Cause Failures
ST1    5 F11_1M= 0                                             $   Maintenance
ST1    6 F11_2 = F11_2H + F11_2C + F11_2M                      $  Two fans required
ST1    7 F11_2H= FN318 * FN320 + FN318 * FN322 + FN320 * FN322 $   Hardware
ST1    8 F11_2C= 3 * CC2FN + CC3FN                             $   Commn Cause
ST1    9 F11_2M= 0                                             $ Maintenance
ST2    1 F21TOP= F21_1 * FS21 + F21_2 * FS22 + F21_3 * FS23    $  EDG Building Ventialtion - 2 EDGs (bus 5A & 3A) available
ST2    2 F21_1 = F21_1H + F21_1C + F21_1M                      $  1 Fan required for success
ST2    3 F21_1H= FN318 * FN320 * FN322 * F211H1                $  Hardware
ST2    4 F21TH1= FN319 * FN321                                 $  Hardware
ST2    5 F21_1C= CC3FN                                         $   Common Cause
ST2    6 F21_1M= 0.0                                           $   Maintenance
ST2    7 F21_2 = F21_2H + F21_2C + F21_2M                      $  Two fans required
ST2    8 F21_2H= 5 * (FN318 * FN320 * FN322 * FN319)           $  Hardware ( 4 fans fail)
ST2    9 F21_2C= CC2FN * 10 * FN318 * FN320 + CC3FN            $   Common Cause
ST2   10 F21_2M= 0.0                                           $  Maintenance
ST2   11 F21_3 = F21_3H + F21_3C + F21_3M                      $ 3 fans required
ST2   12 F21_3H= 3 * (FN318 + FN320 + FN321)                   $   Hardware
ST2   13 F21_3C= CC2FN * FNSING + CC3FN                        $   Common Cause
ST2   14 F21_3M= 0.0                                           $     Maintenance
ST2   15 FNSTNG= FN318 + FN320 + FN322 + FN319 + FN321         $  Fan Failures
ST3    1 F22TOP= F22_1 * FS21 + F22_2 * FS22 + F22_3 * FS23    $ EDG Bld Vent. - 2 EDG. loss of bus 5A or 3A
ST3    2 F22_1 = F22_1H + F22_1C + F22_1M                      $    One fan required
ST3    3 F22_1H= FN318 * FN320 * FN322                         $    Hardware
ST3    4 F22_1C= CC2FN * (FN318 + FN320 + FN322)               $    Common Cause
ST3    5 F22_1M= 0                                             $    Maintenance
ST3    6 F22_2 = F22_2H + F22_2C + F22_2M                      $ 2 Fans required
ST3    7 F22_2H= 3 * FN318 * FN320                             $    Hardware
ST3    8 F22_2C= CC2FN * 3 + CC3FN                             $    Common Cause
ST3    9 F22_2M= 0.0                                           $    Maintenance
ST3   10 F22_3 = F22_3H + F22_3C + F22_3M                      $ 3 Fans required
ST3   11 F22_3H= FN318 + FN320 + FN322                         $    Hardware
ST3   12 F22_3C= 0.0                                           $    Common Cause
ST3   13 F22_3M= 0.0                                           $    Maintenance
ST4    1 F31TOP= F31_1 * FS31 + F31_2 * FS32 + F31_3 * FS33    $ EDG Bld vent - 3EDGs and 5A and 3A available
ST4    2 F31_1 = F31_1H + F31_1C + F31_1M                      $   1 fan requires
ST4    3 F31_1H= FN318 * FN320 * FN322 * F31H1                 $    Hardware (5 fans fail)
ST4    4 F31H1 = FN319 * FN321                                 $    Hardware
ST4    5 F31_1C= CC3FN                                         $  Common Cause
ST4    6 F31_1M= 0.0                                           $    Maintenance
ST4    7 F31_2 = F31_2H + F31_2C + F31_2M                      $   2 fan required
ST4    8 F31_2H= 5 * (FN318 * FN320 * FN322 * FN319)           $    Hardware failure (4 fans required)
ST4    9 F31_2C= CC2FN * 10 * (FN318 * FN320) + CC3FN          $    Common Cause
ST4   10 F31_2M= 0.0                                           $    Maintenance
ST4   11 F31_3 = F31_3H + F31_3C + F31_3M                      $  3 fans required
ST4   12 F31_3H= 3 * FN318 * FN320 * FN322                     $    Hardware failure for three fans
ST4   13 F31_3C= CC2FN * FNSING + CC3FN                        $    Common Cause
ST4   14 FNSTNG= FN318 + FN320 + FN322 + FN319 + FN321         $    Fan Failures
ST4   15 F31_3M= 0.0                                           $    Maintenance
```

TABLE 3.2-17(c)
VENT EQUATION FILE

```
ST5     1 F32TOP= F32_1 * FS32 + F32_2 * FS32 + F32_3 * FS32          $  EDG Bld Vent - 3 EDG - Bus 5A or 3A lost
ST5     2 F32_1 = F32_1H + F32_1C + F32_1M                              $   1 fan required
ST5     3 F32_1H= FN318 * FN320 * FN322                                 $     Hardware
ST5     4 F32_1C= CC2FN * (FN318 + FN320 + FN322)                       $     Common Cause
ST5     5 F32_1M= 0                                                     $     Maintenance
ST5     6 F32_2 = F32_2H + F32_2C + F32_2M                              $   2 fans required
ST5     7 F32_2H= 3 * FN318 * FN320                                     $     Hardware
ST5     8 F32_2C= CC2FN * 3 + CC3FN                                     $     Common Cause
ST5     9 F32_2M= 0.0                                                   $     Maintenance
ST5    10 F32_3 = F32_3H + F32_3C + F32_3M                              $   3 fans required
ST5    11 F32_3H= FN318 + FN320 + FN322                                 $     Hardware
ST5    12 F32_3C= 0.0                                                   $     Common Cause
ST5    13 F32_3M= 0.0                                                   $     Maintenance
STF     1 F3F   = 1.0                                                   $ Guarenteed failure of ST
          FS11  = 0.99                                                  $ Fraction of time (11<TA<98)
          FS12  = 0.01                                                  $ Fraction of time (98<TA<=100)
          FS21  = 0.70                                                  $ Fraction of time (11<TA<=81)
          FS22  = 0.30                                                  $ Fraction of time (81<TA<=98)
          FS23  = 0.01                                                  $ Fraction of time (98<TA<=100)
          FS31  = 0.56                                                  $ Fraction of time (12<TA<=76)
          FS32  = 0.40                                                  $ Fraction of time (76<TA<=94)
          FS33  = 0.04                                                  $ Fraction of time (94<TA<=100)
          FN318 = IPFDFS * TIF + IPFDFR * T6                            $
          FN319 = IPFDFS * TIF + IPFDFR * T6                            $
          FN320 = IPFDFS * TIF + IPFDFR * T6                            $
          FN321 = IPFDFS * TIF + IPFDFR * T6                            $
          FN322 = IPFDFS * TIF + IPFDFR * T6                            $
          CC2FN = .2 * IPBDFS * (1-IPGDFS) * TIF * IPFDFS * CC2FNR      $
          CC2FNR= .2 * IPBDFR * (1-IPGDFR) * IPFDFR * T6                $
          CC3FN = IPBDFS * TIF * IPGDFS * IPFDFS + CC3FNR               $
          CC3FNR= IPBDFR * IPGDFR * IPFDFR * T6                         $
          TIF   = 6                                                     $ Factor applied since fans are only tested every refueling
          T6    = 6                                                     $
```

Table 3.3-1

INITIATING EVENT FREQUENCY

INITIATING EVENT FREQUENCIES	MEAN	5TH	50TH	95TH
LARGE LOCA (LLOCA)	2.01534E-04	7.59093E-06	1.07640E-04	5.22946E-04
MEDIUM LOCA (MLOCA)	4.60682E-04	2.27728E-05	3.11398E-04	1.18222E-03
CONTRIBUTION TO ATWS FROM MLOCA (MLOCAA)	4.60682E-04	2.27728E-05	3.11398E-04	1.18222E-03
SMALL LOCA (SLOCA)	1.68270E-02	1.74231E-03	1.08401E-02	3.69716E-02
CONTRIBUTION TO ATWS FROM SLOCA (SLOCAA)	1.68270E-02	1.74231E-03	1.08401E-02	3.69716E-02
STEAM GENERATOR TUBE RUPTURE (SGTR)	1.29821E-02	2.01586E-04	5.25733E-03	4.14468E-02
CONTRIBUTION TO ATWS FROM SGTR (SGTRA)	1.29821E-02	2.01586E-04	5.25733E-03	4.14468E-02
STEAM LINE BREAK INSIDE CONTAINMENT (MSLBIC)	4.60682E-04	2.27728E-05	3.11398E-04	1.18222E-03
CONTRIBUTION TO ATWS FROM MSLBIC (SLBICA)	4.60682E-04	2.27728E-05	3.11398E-04	1.18222E-03
STEAM LINE BREAK OUTSIDE CONTAINMENT (MSLBOC)	4.98947E-03	1.11231E-04	2.00061E-03	1.25795E-02
CONTRIBUTION TO ATWS FROM MSLBOC (SLBOCA)	4.98947E-03	1.11231E-04	2.00061E-03	1.25795E-02
LOSS OF MAIN FEEDWATER (LOFW)	1.32737E+00	8.58444E-01	1.23646E+00	1.77999E+00
CONTRIBUTION TO ATWS FROM LOFW (LOFWA)	1.28032E+00	8.18756E-01	1.18944E+00	1.72936E+00
INADVERTANT CLOSING OF MSIV (MSIVC)	1.18470E-01	3.28229E-02	9.22316E-02	2.24662E-01
CONTRIBUTION TO ATWS FROM MSIVC (MSIVCA)	1.18470E-01	3.28229E-02	9.22316E-02	2.24662E-01
LOSS OF PRIMARY FLOW (LOPF)	5.68276E-02	6.74026E-03	3.54035E-02	1.37540E-01
CONTRIBUTION TO ATWS FROM LOPF (LOPFA)	5.68276E-02	6.74026E-03	3.54035E-02	1.37540E-01
CORE POWER INCREASE (CPI)	1.88550E-02	8.00216E-04	1.28973E-02	4.68419E-02
CONTRIBUTION TO ATWS FROM CPI (CPIA)	1.88550E-02	8.00215E-04	1.28973E-02	4.68419E-02
TURBINE TRIP (TTRIP)	1.29905E+00	8.73895E-01	1.23512E+00	1.70030E+00
CONTRIBUTION TO ATWS FROM TTRIP (TTRIPA)	1.30227E+00	8.43390E-01	1.23241E+00	1.70504E+00
LOSS OF DC BUS 21 (LODC21)	2.71780E-03	4.98802E-04	1.92707E-03	7.23150E-03
LOSS OF DC BUS 22 (LODC22)	2.71780E-03	4.98802E-04	1.92707E-03	7.23150E-03
CONTRIBUTION TO ATWS FROM LODC21 (LDC21A)	2.71780E-03	4.98802E-04	1.92707E-03	7.23150E-03
CONTRIBUTION TO ATWS FROM LODC22 (LDC22A)	2.71780E-03	4.98802E-04	1.92707E-03	7.23150E-03
REACTOR TRIP (RXTRIP)	2.13299E+00	1.47111E+00	2.08678E+00	2.79505E+00
LOSS OF COMPONENT COOLING WATER (LOCCW)	8.12420E-02	2.09199E-02	6.40318E-02	1.91117E-01
CONTRIBUTION TO ATWS FROM LOCCW (LOCCWA)	8.12420E-02	2.09199E-02	6.40318E-02	1.91117E-01

Table 3.3-1

INITIATING EVENT FREQUENCY
(continued)

INITIATING EVENT FREQUENCIES	MEAN	5TH	50TH	95TH
LOSS OF SERVICE WATER (LOSW)	2.44800E-03	4.42889E-02	1.35560E-01	4.04609E-01
CONTRIBUTION TO ATWS FROM LOSW (LOSWA)	2.44800E-03	4.42889E-02	1.35560E-01	4.04609E-01
LOSS OF OFFSITE POWER (LOSP)	6.91380E-02	1.42207E-02	5.08741E-02	1.77001E-01
CONTRIBUTION TO ATWS FROM LOSP (LOSPA)	6.91380E-02	1.42207E-02	5.08741E-02	1.77001E-01
VERY LARGE LOCA BEYOND ECCS CAPABILITY (BECCSL)	3.00054E-07	6.11051E-09	8.44205E-08	1.11944E-06

Table 3.3-2

HARDWARE FAILURE RATES

BASIC EVENT	DESCRIPTION	MEAN	5TH	50TH	95TH
IPBATR	125V BATTERY - OUTPUT FAILS DURING OPERATION	6.78389E-07	6.10984E-08	3.61084E-07	1.58137E-06
IPBCHR	BATTERY CHARGER - FAILS DURING OPERATION	3.65821E-06	3.96947E-07	1.77326E-06	8.91430E-06
IPBKDC	EDG OUTPUT BREAKER - FAILS TO CLOSE ON DEMAND	5.08712E-03	1.86910E-03	4.77341E-03	8.45629E-03
IPH01L	HX - RUPTURE/EXCESSIVE LEAKAGE DURING OPERATION	1.39729E-06	7.81616E-08	6.08698E-07	4.09093E-06
IPBATD	125V DC BATTERY - FAILURE OF OUTPUT ON DEMAND	4.80053E-04	7.40655E-05	3.29401E-04	1.11000E-03
IPBKDO	EDG OUTPUT BREAKER- FAILURE TO OPEN ON DEMAND	3.92438E-04	4.43411E-05	2.80538E-04	9.20206E-04
IPBKDT	EDG OUTPUT BREAKER - XFERS OPEN DURING OPERATION	7.24766E-07	5.25251E-08	3.59729E-07	1.86492E-06
IPBKRC	BKR (>480V) - FAILURE TO CLOSE ON DEMAND	7.58315E-04	2.26704E-04	6.23400E-04	1.67490E-03
IPBKRO	BKR (>= 480V) - FAILURE TO OPEN ON DEMAND	5.71073E-04	1.41421E-04	4.47214E-04	1.41421E-03
IPBKRT	BKR (>= 480V) - XFERS OPEN DURING OPERATION	6.29553E-07	4.97728E-08	3.36460E-07	1.39986E-06
IPBUSO	BUS - FAILURE DURING OPERATION	4.57260E-07	8.18747E-08	3.23867E-07	1.04765E-06
IPD01R	EDG - FAILURE DURING OPERATION	4.16350E-03	1.80312E-03	3.75721E-03	6.70736E-03
IPD01S	EDG - FAILURE TO START ON DEMAND	3.10806E-03	1.39019E-03	2.81699E-03	5.61119E-03
IPFUSO	CONTROL FUSES - FAILURE DURING OPERATION	4.54127E-06	6.93521E-07	3.02430E-06	1.27866E-05
IPFUSE	FUSES (NOT CONTROL) - FAILURE DURING*OPERATION	3.99100E-07	1.78388E-08	1.73447E-07	1.13139E-06
IPPP1R	PIPE < 3 INCHES, FAILURE PER SECTION*	8.59996E-09	1.98481E-11	1.80235E-09	2.02374E-08
IPPP2R	PIPE > 3 INCHES, FAILURE PER SECTION*	8.59996E-10	1.98481E-12	1.80235E-10	2.02374E-09
IPP02S	TURBINE DRIVEN AFWP 22 - FAILURE TO START	4.25012E-02	1.42765E-02	3.39932E-02	8.08937E-02
IPP03S	SIS PUMPS - FAILURE TO START	9.68611E-03	4.49242E-03	8.70312E-03	1.55993E-02
IPP04S	RHR PUMPS - FAILURE TO START	1.08359E-02	4.99069E-03	9.70632E-03	1.71695E-02
IPP05S	CCW PUMPS - FAILURE TO START	1.01649E-02	4.84674E-03	9.10629E-03	1.64106E-02
IPP06S	ACCW PUMPS - FAILURE TO START	1.11973E-02	5.00293E-03	1.00190E-02	1.74820E-02
IPP07S	SWS PUMPS - FAILURE TO START	1.04073E-03	3.84288E-04	8.58408E-04	1.96106E-03
IPP08S	RECIRC PUMPS - FAILURE TO START	1.14841E-02	5.01329E-03	1.02609E-02	1.77028E-02
IPP09S	CS PUMPS - FAILURE TO START	1.10414E-02	4.99754E-03	9.88541E-03	1.73526E-02
IPP10S	MOTOR DRIVEN AFWP - FAILURE TO START	1.10622E-02	5.05313E-03	1.00033E-02	1.70789E-02
IPP11S	EDG FUEL OIL XFER PUMP - FAILURE TO START	3.65274E-03	1.63382E-03	3.31066E-03	6.59453E-03
IPP12S	CHR PUMPS - FAILURE TO START	9.65891E-03	4.47516E-03	8.67339E-03	1.55310E-02
IPP02R	AFWP 22 - FAILURE DURING OPERATION	2.08885E-03	1.62858E-04	1.13204E-03	5.93239E-03
IPP03R	SI PUMP - FAILURE DURING OPERATION	3.39734E-05	2.67942E-06	1.76459E-05	9.17006E-05
IPP04R	RHR PUMP - FAILURE DURING OPERATION	4.69119E-05	3.34166E-06	2.33071E-05	1.56692E-04

Table 3.3-2

HARDWARE FAILURE RATES (continued)

BASIC EVENT	DESCRIPTION	MEAN	5TH	50TH	95TH
IPP05R	CCW PUMP - FAILURE DURING OPERATION	1.29390E-05	2.65879E-06	1.04642E-05	2.64183E-05
IPP06R	ACCW PUMP - FAILURE DURING OPERATION	3.52747E-05	2.73232E-06	1.75144E-05	1.02260E-04
IPP07R	SWS PUMP - FAILURE DURING OPERATION	3.00288E-05	9.98591E-06	2.53921E-05	6.31794E-05
IPP08R	RECIRC PUMP - FAILURE DURING OPERATION	3.40890E-05	2.68170E-06	1.76649E-05	9.24907E-05
IPP09R	CONT SPRAY PUMP - FAILURE DURING OPERATION	3.40029E-05	2.68000E-06	1.76507E-05	9.19032E-05
IPP10R	MOTOR DRIVEN AF - FAILURE DURING OPERATION	9.15642E-05	7.98928E-06	5.26195E-05	1.87857E-04
IPP11R	EDG FUEL XFER PUMP - FAILURE DURING OPERATION	2.80312E-05	2.53674E-06	1.53614E-05	8.96626E-05
IPP12R	CHARGING PUMP - FAILURE DURING OPERATION	7.27129E-05	2.44949E-05	6.08929E-05	1.60852E-04
IPR01D	MASTER RELAY - FAILURE ON DEMAND	1.10670E-04	1.36326E-05	7.01572E-05	2.72804E-04
IPRPBD	RX TRIP BKR - FAILURE ON DEMAND	1.55404E-03	5.79371E-04	1.41040E-03	2.32182E-03
IPROD1	SINGLE CONTROL ROD - FAILURE TO INSERT ON DEMAND	2.37784E-05	1.79042E-06	1.01750E-05	6.40295E-05
IPSIGD	MSIV AUTO CLOSURE SIGNAL - FAILURE ON DEMAND	6.79814E-07	2.43086E-08	2.49825E-07	2.46681E-06
IPSW1D	DC TRANSFER SWITCH - FAILURE TO XFER ON DEMAND	1.56595E-05	7.00428E-06	1.41930E-05	2.82712E-05
IPSW2D	BISTABLE SWITCH - FAILURE TO OPEN ON DEMAND	3.89000E-07	5.97715E-08	2.57952E-07	9.15986E-07
IPSW3D	SWITCHES - SHORT ACROSS CONTACTS	4.28000E-07	4.68689E-09	8.81411E-08	1.59086E-06
IPS01P	SW STRAINER - PLUGS PER HOUR	7.22907E-05	4.87717E-05	7.14023E-05	9.30478E-05
IPS02P	RECIRC SUMP - PLUGS PER HOUR	5.03590E-05	9.20840E-09	9.43650E-07	9.86520E-05
IPS03P	CONTAINMENT SUMP - PLUGS PER HOUR	5.03590E-05	9.20840E-09	9.43650E-07	9.86520E-05
IPTNKL	CONDENSATE STORAGE TANK - FAILURE DURING OPER	2.64380E-08	7.59072E-10	1.04078E-08	7.56313E-08
IPTNK2	CCS SURGE TANK - FAILURE DURING OPERATION	2.64380E-08	7.59072E-10	1.04078E-08	7.56313E-08
IPTNK3	RWST - FAILURE DURING OPERATION	2.64380E-08	7.59072E-10	1.04078E-08	7.56313E-08
IPTRID	TRIP RELAYS - FAILURE TO OPEN ON DEMAND	2.17091E-04	1.30772E-05	1.00513E-04	7.43985E-04
IPT01R	XFORMERS (>= 480V) - FAILURE DURING OPERATION	5.62209E-07	9.92323E-08	3.98747E-07	1.23157E-06
IPT02F	TRANSMITTER - FAILURE TO PROVIDE PROPER OUTPUT	6.52220E-06	8.48038E-07	4.10035E-06	1.91935E-05
IPVASD	TURBINE AUTOSTOP VLV - FAILURE TO OPER ON DEMAND	1.55295E-03	7.63991E-05	8.73517E-04	3.64569E-03
IPV01T	MAN OR MOV - XFERS CLOSED DURING OPERATION	4.69225E-08	6.49108E-09	3.58427E-08	1.01772E-07
IPV02D	CHK VLV (NOT MSIV) - FAILS TO OPERATE ON DEMAND	3.76623E-05	1.25244E-05	3.18470E-05	7.92400E-05
IPV02L	CHK VLV (NOT MSIV) - LEAKAGE DURING OPERATION	2.41778E-06	3.46410E-07	1.41421E-06	6.16872E-06
IPV03C	SAFETY VLV - FAILS TO RESEAT AFTER 2-PHASE FLOW	4.31938E-02	2.34553E-03	1.34487E-02	9.00400E-02
IPV03L	RELIEF/SAFETY VALVE - PREMATURE OPEN OR LEAKAGE	2.26932E-06	6.33312E-07	1.79784E-06	4.27010E-06
IPV04D	MOV - FAILS TO XFER POSITION ON DEMAND	1.59192E-03	7.40114E-04	1.33829E-03	2.36631E-03
IPV05D	AOV - FAILS TO OPERATE ON DEMAND	8.19563E-04	2.82843E-04	6.97802E-04	1.36285E-03

Table 3.3-2

HARDWARE FAILURE RATES (continued)

BASIC EVENT	DESCRIPTION	MEAN	5TH	50TH	95TH
IPV05L	AIR OPERATED VLV - XFERS OPEN/EXCESSIVE LEAKAGE	2.12308E-07	1.62082E-08	1.13300E-07	5.34852E-07
IPV05T	AIR OPERATED VLV - XFERS CLOSED DURING OPERATION	2.42672E-07	1.48575E-08	1.09128E-07	6.91394E-07
IPV06D	SOLENOID OPER VLV - FAILURE TO OPER ON DEMAND	1.52264E-03	2.82843E-04	1.10524E-03	3.15510E-03
IPV07D	TURBINE STOP/CNTRL VLV - FAILS TO OPER ON DEMAND	1.10438E-04	2.92351E-05	8.93108E-05	2.19315E-04
IPV08D	MSIV - FAILURE ON DEMAND	4.99819E-03	1.35355E-03	3.68222E-03	1.01894E-02
IPV10C	PORV - FAILURE TO RESEAT ON DEMAND	1.50522E-02	4.81422E-03	1.24494E-02	2.85392E-02
IPV10D	PORV FAILURE TO OPEN ON DEMAND	3.74533E-03	9.95087E-04	2.98047E-03	7.51273E-03
IPV12L	SWS CHECK VLV - FAILURE TO SEAT/EXCESSIVE LEAKGE*	1.19543E-06	2.53341E-07	7.43920E-07	2.77758E-06
IPFLTS	FILTERS (LIQUID) - PLUGS PER HOUR*	7.67825E-06	5.59939E-07	4.21096E-06	2.05542E-05
IPSW3S	SWITCHES - SHORT ACROSS CONTACTS*	4.28000E-07	1.63056E-09	5.00225E-08	1.47678E-06
IPV03D	RELIEF SAFETY VLV - FAILURE TO OPEN ON DEMAND*	2.99541E-04	1.15510E-05	1.13930E-04	1.08008E-03
IPFDFR	EDG BLDG VENTILATION FANS - FAIL DURING OPER*	7.89000E-06	2.01329E-06	6.20209E-06	1.86287E-05
IPFDFS	EDG BLDG VENTILATION FANS - FAILURE TO START*	4.84000E-04	5.88855E-05	2.96916E-04	1.44856E-03
IPF01R	FCU'S - FAILURE DURING OPERATION	2.62024E-06	7.23289E-07	2.30236E-06	5.11038E-06
IPF01S	FCU'S - FAILURE TO START ON DEMAND	1.72463E-03	3.25428E-04	1.21721E-03	3.72917E-03
IPP13R	PWST PUMPS - FAILURE DURING OPERATION	3.06337E-05	2.61092E-06	1.63756E-05	9.91102E-05
IPP13S	PWST PUMPS - FAILURE TO START	1.17000E-02	5.62698E-03	1.07617E-02	2.02571E-02
IPV01L	MANUAL VLV XFERS OPEN/EXCESSIVE LEAK DURING OPER	9.26980E-08	9.66294E-09	5.04794E-08	2.33649E-07
IPV13D	MANUAL VALVES FAILS TO OPEN ON DEMAND	6.83000E-04	1.24376E-04	4.83028E-04	1.82195E-03
IPVAC1	ATMOSPHERIC RELIEF FAILS TO OPEN	1.40000E-02	6.58898E-03	1.28221E-02	2.45486E-02
IPVSV1	SAFETY VALVE FAILS TO RECLOSES	8.89000E-03	4.46192E-04	3.80371E-03	3.11990E-02
IPP14S	BORIC ACID XFER PUMP - FAILURE TO START	1.00512E-02	4.89848E-03	9.26902E-03	1.72665E-02
IPP14R	BORIC ACID XFER PUMP - FAILURE DURING OPERATION	3.06475E-05	2.58427E-06	1.63126E-05	9.93575E-05
IPHERA	REACTOR FAILS TO TRIP WITHIN ONE MINUTE	1.25000E-01	3.29133E-02	9.91609E-02	2.91402E-01
IPRPIC	RPS INSTRUMENTATION CHANNEL - FAILURE ON DEMAND*	6.81284E-05	2.11539E-06	2.34501E-05	2.49700E-04
IPTR1D	TRIP RELAY - FAILURE TO OPEN ON* DEMAND	2.17091E-04	1.30772E-05	1.00513E-04	7.43985E-04
IPCCLL	RPS CABLE LINE TO GROUND SHORT*	7.52000E-06	3.41423E-07	3.07816E-06	2.66904E-05
IPCCL2	RPS CONTROL CABLE, LINE TO LINE SHORT*	3.22000E-06	1.46015E-07	1.31732E-06	1.14301E-05
IPDG1R	EDG FAILURE TO RUN FOR THE 1ST HR	7.76608E-03	1.82486E-03	5.84826E-03	1.56894E-02
IPDG2R	EDG FAILS TO RUN AFTER THE 1ST HR	1.54816E-03	2.78331E-04	1.08160E-03	3.54760E-03

Table 3.3-3

MAINTENANCE FREQUENCIES AND DURATIONS

BASIC EVENT	DESCRIPTION	MEAN	5TH	50TH	95TH
IPDD01	MAINTENANCE DURATION FOR THE EDG 21, 22, 23	4.99611E+01	4.21851E+01	4.94694E+01	5.59436E+01
IPDF01	MAINTENANCE FREQUENCY FOR EDG 21, 22, 23	9.19530E-04	8.44867E-04	9.05512E-04	1.01286E-03
IPPD02	MAINTENANCE DURATION FOR AFWP 22	8.83089E+00	6.94696E+00	8.72298E+00	1.08853E+01
IPPF02	MAINTENANCE FREQUENCY FOR AFWP 22	2.88392E-04	1.89513E-04	2.75948E-04	3.81609E-04
IPPD03	MAINTENANCE DURATION FOR SIS PUMPS	2.14883E+00	7.14580E-01	1.81703E+00	4.52105E+00
IPPF03	MAINTENANCE FREQUENCY FOR SIS PUMPS	1.33642E-04	8.95605E-05	1.27448E-04	1.73205E-04
IPPD04	MAINTENANCE DURATION FOR RHR PUMPS	3.34522E+01	1.68478E+01	3.04594E+01	5.18704E+01
IPPF04	MAINTENANCE FREQUENCY FOR RHR PUMPS	6.35440E-05	3.04606E-05	5.77964E-05	1.00758E-04
IPPD05	MAINTENANCE DURATION FOR CCW PUMPS	2.77706E+01	1.11277E+01	2.53231E+01	4.64289E+01
IPPF05	MAINTENANCE FREQUENCY FOR CCW PUMPS	1.44590E-04	3.90814E-05	1.15568E-04	3.33454E-04
IPPD06	MAINTENANCE DURATION FOR ACCW PUMPS	1.65863E+01	1.05828E+01	1.60000E+01	2.39343E+01
IPPF06	MAINTENANCE FREQUENCY FOR ACCW PUMPS	1.84890E-05	5.16916E-06	1.56634E-05	3.45821E-05
IPPD07	MAINTENANCE DURATION FOR SWS PUMPS	4.82786E+00	1.60547E+00	4.08240E+00	1.01576E+01
IPPF07	MAINTENANCE FREQUENCY OF SWS PUMPS	7.36178E-04	1.89566E-04	5.80226E-04	1.73181E-03
IPPD09	MAINTENANCE DURATION FOR CONT SPRAY PUMPS	1.03914E+01	6.08133E+00	9.48163E+00	1.46788E+01
IPPF09	MAINTENANCE FREQUENCY FOR CONT SPRAY PUMPS	8.43631E-05	4.24264E-05	7.93466E-05	1.24066E-04
IPPD10	MAINTENANCE DURATION FOR MOTOR DRVN AFW PUMPS	2.00974E+01	1.28230E+01	1.93870E+01	2.90009E+01
IPPF10	MAINTENANCE FREQUENCY FOR MOTOR DRVN AFW PUMPS	2.30574E-04	1.62034E-04	2.27525E-04	2.79832E-04
IPPD11	MAINTENANCE DURATION FOR EDG FUEL OIL PUMPS	6.56135E+01	4.18642E+01	6.32940E+01	9.46813E+01
IPPF11	MAINTENANCE FREQUENCY FOR EDG FUEL OIL PUMPS	1.37098E-05	3.80028E-06	1.14397E-05	2.60695E-05
IPPD12	MAINTENANCE DURATION FOR CHARGING PUMPS	5.76244E+01	3.67668E+01	5.55873E+01	8.31529E+01
IPPF12	MAINTENANCE FREQUENCY FOR CHARGING PUMPS	7.63016E-04	6.52836E-04	7.52306E-04	8.53531E-04
IPPF13	MAINTENANCE FREQUENCY FOR THE PWST PUMPS	1.48194E-05	4.11009E-06	1.19319E-05	3.38100E-05
IPPD13	MAINTENANCE DURATION FOR THE PWST PUMPS	1.78244E+01	7.35711E+00	1.58767E+01	3.36354E+01
IPPD14	MAINTENANCE DURATION FOR BORIC ACID XFER PUMPS	1.78294E+01	7.36286E+00	1.58829E+01	3.36356E+01
IPPF14	MAINTENANCE FREQUENCY FOR THE BORIC ACID PUMPS	1.51043E-05	4.37515E-06	1.23099E-05	3.38255E-05
IPFD01	MAINTENANCE DURATION FOR THE FCU'S	4.11967E+01	3.26671E+01	4.08358E+01	4.94246E+01
IPFF01	MAINTENANCE FREQUENCY FOR THE FCU'S	9.49778E-05	6.65089E-05	9.05479E-05	1.21442E-04
IPPD01	MAINTENANCE DURATION OF THE CCW PUMPS	5.81789E+01	2.60226E+01	5.27305E+01	1.05034E+02
ILPD12	MAINTENANCE DURATION (LONG) CHG PUMPS	1.10715E+01	1.41421E+00	6.09162E+00	2.77779E+01
ILPF12	MAINTENANCE FREQUENCY (LONG) FOR CHG PUMPS	1.64761E-05	3.46410E-05	6.14354E-05	9.43398E-05
IPHF02	MAINTENANCE FREQUENCY FOR CCW HEAT EXCHANGERS	5.20298E-05	2.46476E-05	4.83869E-05	8.15982E-05

Table 3.3-4

TEST DURATIONS

BASIC EVENT	DESCRIPTION	MEAN	5TH	50TH	95TH
IPRT01	SAFEGUARDS ACTUATION MASTER RELAY	5.00000E+00	3.50131E+00	4.88086E+00	6.74477E+00
IPPT01	CONTAINMENT SPRAY PUMPS	7.20000E-01	4.65693E-01	6.95842E-01	1.02902E+00
IPPT07	SERVICE WATER PUMPS	5.50000E-01	2.27650E-01	4.90202E-01	1.03632E+00
IPMDRT	REACTOR PROTECTION SYSTEM LOGIC CHANNEL	4.30000E+00	3.11447E+00	4.21344E+00	5.65476E+00

TABLE 3.3-5
Pre-Accident Human Error Probabilities

Task	NRC Handbook Best Estimate	NRC Handbook Upper/lower bounds	This Study Mean	This Study Median	5%	95%
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 stste as the desired valve or the valves are MOVs of such type that the ststus cannot be determined at the valve itself.	5E-3	(2E-3 - 2E-3)	9.0E-03	5.0E-03	8.3E-04	2.9E-02
2. Change or restore wrong MOV or Switch or circuit breaker in a group of similar appearing items.	3E-3	(1E-3 - 1E-2)	4.7E-03	3.0E-03	6.4E-04	1.4E-02
ERRORS OF OMISSION						
1. Non passive tasks (maintenance test, calibration); using procedures with checkoff provisions.						
i. Short list (<10 special instruction items).	1E-3	(5E-4 - 5E-3)	2.2E-03	9.8E-04	9.7E-05	6.2E-03
ii. Long list (>10 special instruction items)	3E-3	(1E-3 - 1E-2)	4.7E-03	2.9E-03	5.4E-04	1.2E-02
2. Passive Tasks such as walkaround inspections.						
i. Failure to recognize an incorrect status when checking each item as it is looked at.	1E-2	(5E-3 - 5E-2)	2.2E-02	1.0E-02	9.7E-04	6.2E-02
ii. Failure to recognize an incorrect status when checking off several items after looking at several	1E-1	(5E-2 - 5E-1)	2.2E-1	3.1E-01	9.7E-03	4.7E-01

TABLE 3.3-6
Overview of Pre Accident Operator Actions in the Indian Point 2 IPE

SYSTEM	DESCRIPTION	HUMAN ERROR PROBABILITY	COMMENT
		2.00E-04	
AFS	REALIGN VALVES ON ALL AFS PUMPS VALVES FOLLOWING TEST	1.15E-05	
CSS	REALIGN VALVE ON SINGLE PUMP FOLLOWING TEST	2.00E-04	
CSS	REALIGN VALVES ON BOTH PUMPS FOLLWING TEST	1.15E-05	
EPS	REALIGN SINGLE EDG CONTROL SWITCH FOLLOWING TEST	6.01E-06	Tales credit for operators checking on control switch status every 4 hours
EPS	REALIGN TWO EDG CONTROL SWITCH FOLLOWING TEST	3.00E-07	Takes credit for operators checking on control switch status very 4 hours
EPS	REALIGN THREE EDG CONTROL SWITCHES FOLLOWING TEST	1.50E-08	Takes credit for operators checking on control switch status very 4 hours
EPS	UNDISCOVERED MAINTENANCE ERROR ON ONE EDG	4.27E-04	
EPS	UNDISCOVERED MAINTENANCE ERROR ON TWO EDGS	2.13E-05	
EPS	UNDISCOVERED MAINTENANCE ERROR ON THREE EDGS	1.07E-05	
SWS	REALIGN SERVICE WATER SYSTEM SWITCH	5.14E-05	
SWS	REALIGN VALVES ON STANDBY PUMP FOLLOWING TEST	5.60E-05	

Table 3.3-7
(sheet 1 of 5)
Overview of Post Accident Operator Actions in Indian Point 2 IPE

CODE	DESCRIPTION	HUMAN ERROR PROBABILITY	Time Window (T_w)	COMMENTS
IPOP01	ESTABLISH FLOW FROM TURBINE DRIVEN AFS PUMP PRIOR TO SG DRYOUT GIVEN TRANSIENT LOCA, OR LOSP	4.00E-03	60 MINS	
IPOP02	RESET TURBINE DRIVEN AFS (LOCAL CONTROL) PRIOR TO SG DRYOUT GIVEN TRANSIENT LOCA OR LOSP	2.91E-02	60 MINS	No credit given for this action if time window less than 1 hour
IPOP03	ESTABLISH FLOW FROM TURBINE DRIVEN AFS PUMP PRIOR TO SG DRYOUT FOR COOLING RECOVERY FOLLOWING LOCA WITH FAILURE OF HPI	1.10E-02	10 MINS	
IPOP04	ESTABLISH FLOW FROM TURBINE DRIVEN AFS PUMP PRIOR TO SG DRYOUT-ATWS WITH POWER LEVEL < 40% ATWS	1.30E-02	10 MINS	
IPOP05	SWITCHOVER SUCTION OF FROM CST TO CITY WATER	4.00E-03	60 MINS	
IPOPFO	RESET MCC'S (LOCAL) FOLLOWING LOSP	3.72E-05	40-50 MINS (after LOSP) 20-25 MINS (after Lo EDG day tank)	
IPOPB1	CLOSE PORV BLOCK VALVE DURING A TRANSIENT	4.00E-03	60 MINS	
IPOPB3	CLOSE PORV BLOCK VALVES FOLLOWING LOSS OF OFFSITE POWER EVENT WITH STUCK OPEN PORV	4.00E-03	60 MINS	
IPOPB4	OPERATOR FAILS TO SECURE PRESSURE RELIEF FOLLLOWING ATWS	1.00E-01	N/A	
IPOPA1	INITIATE RPS OR DE-ENERGIZE MG SETS WITHIN 1 MIN - ATWS	4.00E-03	1 MIN	IPOPA1, IPOPA2 and IPOPA3 modeled as dependent actions in system equations

Table 3.3-7
(sheet 2 of 5)
Overview of Post Accident Operator Actions in Indian Point 2 IPE

CODE	DESCRIPTION	HUMAN ERROR PROBABILITY	Time Window (T_w)	COMMENTS
IPOPA2	INITIATE RPS, DE-ENERGIZE MG SETS OR INITIATE EMERGENCY BORATION WITHIN 10 MINS FOLLOWING ATWS	4.00E-03	10 MINS	
IPOPA3	DE-ENERGIZE MG SETS LOCALLY - ATWS	4.00E-03	10 MINS	
IPOPFB	INITIATE PRIMARY FEED/BLEED COOLING FOLLOWING LOSS OF AFS	7.10E-03	7.5 MINS (After 40% wide range SG Level reached)	
IPOPLS	INITIATE CHARGING PUMP FLOW & EST CITY WATER COOLING GIVEN LOSS OF CCW TO RCP SEALS	4.00E-03	30 MINS	30 mins is available to initiate a charging at max speed to prevent RCP seal LOCA. A further 45 minutes is available to establish City Water Cooling to the Charging Pumps
IPOPIS	IDENTIFY AND ISOLATE RUPTURED SG PRIOR TO OVERFILL	1.70E-02	15 MINS	SG overfill will not occur for at 30 mins after SGTR event however response must begin at 15 mins in order to complete RCS cooldown and depressurization in time.
IPOPCD	COOLDOWN AND DEPRESSURIZE RCS EARLY GIVEN SGTR	3.60E-03	N/A	Time dependent cognitive response accounted in IPOPIS event
IPOPCE	COOLDOWN AND DEPRESSURIZE RCS EARLY GIVEN SGTR AND FAILURE OF AFS	7.10E-03	N/A	Requires initiation of Feed and Bleed or blow down of ruptured SG, depending on SG level. Error probabilty assumed to be as IPOPFB (initiation of feed and bleed).
IPOPD1	DEPRESSURIZE FOR CORE COOLING RECOVERY GIVEN SMALL OR MEDIUM LOCA WITH FAILURE OF HP INJECTION	5.62E-02	3.6 MINS (After core exit temp = 1200 ^{o}F)	

Table 3.3-7
(sheet 3 of 5)
Overview of Post Accident Operator Actions in Indian Point 2 IPE

CODE	DESCRIPTION	HUMAN ERROR PROBABILITY	Time Window (T_w)	COMMENT
IPOPD3	POST LOCA DEPRESSURIZATION FOLLOWING SMALL LOCA	1.54E-03	1.4 HRS	Time window excludes time required to achieve cooldown and depressurization at 100 deg F per hr.
IPOPD4	POST LOCA DEPRESSURIZATION FOLLOWING MEDIUM LOCA	1.00E-01	N/A	Screening error rate applied. Note system accounts for 30 % of medium LOCAs where break size may prevent depressurization prior to RWST being exhausted.
IPOPR1	ALIGN RHR TO RECIRCULATION COOLING MODE GIVEN BOTH RECIRCULATION PUMPS HAVE FAILED FOLLOWING SMALL OR MEDIUM LOCA	1.50E-03		
IPOPR2	SWITCHOVER TO HIGH PRESSURE RECIRCULATION GIVEN MEDIUM LOCA	3.60E-03	3.1 MINS (after low RWST level	Time window excludes time to complete over steps to high pressure recirculation
IPOPR3	INADVERTENTLY SWITCH OFF HP INJECTION PUMPS AT CONCLUSION OF RECIRCULATION SWITCH OVER PROCEDURE AND DO NOT RECOVER	2.30E-05		Requires an initial slip and subsequent failure to recover. At least an hour would be available for recovery and in most cases, much longer.
IPOPR4	SWITCHOVER TO LOW HEAD RECIRCULATION GIVEN SMALL OR MEDIUM LOCA WITH SUCCESSFUL POST LOCA DEPRESSURIZATION	1.20E-04	65 MINS	Time window excludes time to complete switch over steps to low pressure in EOP ES 1.3
IPOPRA	SWITCHOVER TO HIGH HEAD RECIRCULATION FOLLOWING SMALL LOCA	3.70E-04	58 MINS	Time Window excludes time to complete steps to achieve high pressure in EOP ES 1.3
IPOPR5	ALIGN RHR PUMPS TO RECIRCULATION GIVEN RECIRCULATION PUMPS HAVE FAILED GIVEN LARGE LOCA	2.60E-01	N/A	Time dependent cognitive response included in IPOPR6 (Switch over to Recirculation)

Table 3.3-7
(sheet 4 of 5)
Overview of Post Accident Operator Actions in Indian Point 2 IPE

CODE	DESCRIPTION	HUMAN ERROR PROBABILITY	Time Window (T_w)	COMMENT
IPOPR6	SWITCHOVER TO LOW PRESSURE RECIRC GIVEN LARGE LOCA	1.70E-03 (after RWST	3.8 MINS	Time window excludes time required to excute steps to complete switchover to pressure recirculation
IPOPR9	ALIGN RECIRCULATION IN CONTAINMENT SPRAY MODE	1.20E-04	16 HOURS	
IPOPSB	OPERATOR INITIATES PRIMARY BLEED (ONLY) - ATWS	1.00E-01	N/A	Screening value
IPOPC1	MANIPULATIVE OPERATOR ERROR ASSOCIATED WITH DEPRESSURIZATION OF RCS LATE FOLLOWING SGTR	2.40E-04	N/A	Time dependent cognitive response in IPOPC1
IPOPC2	COGNITIVE RESPONSE HUMAN ERROR ASSOCIATED OF RCS LATE FOLLOWING SGTR	4.90E-04	7.3 HRS (after SG overfill)	Excludes time require to achieve cooldown and depressurization at 100 deg F per hour
IPOPC3	COGNITIVE HUMAN ERROR ASSOCIATED WITH ISOLATING RUPTURE SG - LATE FOLLOWING SGTR	1.00E-05	13.7 HRS (after SG overfill)	
IPOPC4	OPERATOR ISOLATES RUPTURED SG LATE GIVEN FAILURE OF AFS AND HP	7.20E-03	1.5 HRS	

Table 3.3-7
(sheet 5 of 5)
Overview of Post Accident Operator Actions in Indian Point 2 IPE

CODE	DESCRIPTION	HUMAN ERROR PROBABILITY	Time Window (T_w)	COMMENTS
IPOPS1	MANIPULATIVE HUMAN ERROR ASSOCIATED WITH ISOLATING RUPTURE SG LATE	1.20E-04	N/A	Time dependendent cognitive response addressed IPOPC3
IPOPRH	OPERATOR FAILS TO INITIATE RHR	1.20E-03		Time dependent cognitive error excluded given success of IPOPC1 (RCS Cooldown and depressurize -late)
IPOPRW	OPERATOR FAILS TO PROVIDE MAKEUP TO THE RWST	1.20E-03		Time dependent cognitive error excluded given success of IPOPC1 (RCS Cooldown and Depressurize-late)

TABLE 3.4-1: IP2 IPE Core Damage Sequences with a frequency of greater than 1.0E-07 per year.

Initiating Event	Sequence No.	Sequence Frequency	Top Event Failures
1. RXTRIP	5	3.9718E-06	///L11*O11
2. SLOCA	2	3.2058E-06	///LR6*CSF
3. LOFW	5	2.4716E-06	///L11*O11
4. TTRIP	5	2.4249E-06	///L11*O11
5. LLOCA	3	1.8397E-06	///LR1*CSF
6. MLOCA	5	1.2152E-06	///DZ2*HR1*CSF
7. SLOCA	24	8.8700E-07	///RW2
8. SLOCA	18	7.9447E-07	///HP3*Y11
9. LOSP	1407	5.4893E-07	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F //P11*T11*L13*P21*T21*SEF*SNF*O1F*FCF*RHF
10. SLOCA	77	5.2955E-07	//EA1*EBC/HPF*L1F*FCF*LIF*CSF
11. MLOCA	11	5.0485E-07	///AS1
12. SGTR	6	4.9328E-07	///O41*O5A
13. LOSP	1211	4.4837E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22
14. LOSP	1162	4.2930E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27
15. SGTR	113	4.0521E-07	//EA1*EBC/HPF*L1F
16. BECCSL	1	2.9335E-07	///
17. LODC21	2	2.4447E-07	/D1F//L11*O1F
18. LLOCA	8	2.3198E-07	///LP1
19. LODC22	2	2.2997E-07	/D2F//L11*O1F
20. SGTR	11	2.2253E-07	///OS1*SO1*LR4
21. LLOCA	6	2.2240E-07	///AS1
22. MSIVC	5	2.2061E-07	///L11*O11

TABLE 3.4-1: IP2 IPE Core Damage Sequences with a frequency of greater than 1.0E-07 per year.

Initiating Event	Sequence No.	Sequence Frequency	Top Event Failures
23. LOSP	1216	2.1070E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22*SE1
24. LOSP	1167	2.0175E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27*SE1
25. LOCCW	3	1.9188E-07	//CCF/L11*HRG*CSF
26. LOSP	1092	1.8031E-07	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F//P11*T11*L1 2*P21*T21*SEF*SNF*O1F
27. LOSP	3162	1.7851E-07	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F *G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF /P11*STF*T12*L1F*HPF*FCF*LIF*CSF
28. SGTR	13	1.6504E-07	///OS1*O5E
29. RXTRIP	3	1.6006E-07	///L11*HRA*CSF
30. RXTRIP	9	1.5840E-07	///L11*HP3
31. LODC21	146	1.5598E-07	/W21*D1F*D23//L1F*O1F*FCF*CSF
32. LOCCW	5	1.4796E-07	//CCF/L11*O11
33. LOFWA	20	1.4683E-07	///RT1*PL1*L1A
34. TTRIPA	20	1.4406E-07	///RT1*PL1*L1A
35. LOSP	1177	1.4302E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F ///P11*STF*T12*P31*T32*SG1
36. LLOCA	2	1.3270E-07	///RC1
37. LOSP	1225	1.1249E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22*VF5*CF5
38. LOSP	3950	1.0907E-07	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*L13*P21*T22*DPF
39. LOFWA	12	1.0599E-07	///RT1*PL1*BR1*MD2
40. LOPF	5	1.0582E-07	///L11*O11
41. LOSP	2824	1.0444E-07	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*P31*T32*C13*C27*DPF
42. TTRIPA	12	1.0399E-07	///RT1*PL1*BR1*MD2

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 1 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IA	RXTRIP	5	3.9718E-06	///L11*011	PDS24
IA	LOFW	5	2.4716E-06	///L11*011	PDS24
IA	TTRIP	5	2.4249E-06	///L11*011	PDS24
IA	LODC21	2	2.4447E-07	/D1F//L11*O1F	PDS24
IA	LODC22	2	2.2997E-07	/D2F//L11*O1F	PDS24
IA	MSIVC	5	2.2061E-07	///L11*011	PDS24
IA	LOSP	1216	2.1070E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*SE1	PDS1
IA	LOCCW	3	1.9188E-07	//CCF/L11*HRG*CSF	PDS34
IA	LOSP	1092	1.8031E-07	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F//P11*T11*L12*P21*T21*SEF*SNF*O1F	PDS24
IA	LOSP	3162	1.7851E-07	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F*G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L1F*HPF*FCF*LIF*CSF	PDS10
IA	RXTRIP	9	1.5840E-07	///L11*HP3	PDS24
IA	LODC21	146	1.5598E-07	/W21*D1F*D23//L1F*O1F*FCF*CSF	PDS32
IA	LOFWA	20	1.4683E-07	///RT1*PL1*L1A	PDS24
IA	LOCCW	5	1.4796E-07	//CCF/L11*011	PDS24
IA	LOSP	1225	1.1249E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*VF5*CF5	PDS21
IA	LOSP	3950	1.0907E-07	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*DPF	PDS1
IA	LOFWA	12	1.0599E-07	///RT1*PL1*BR1*MD2	PDS24
IA	LOPF	5	1.0582E-07	///L11*011	PDS24
IA	LOFW	9	9.8571E-08	///L11*HP3	PDS24
IA	LOSP	3164	9.8483E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F*G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L1F*P21*T22*FCF*DPF*LIF	PDS5
IA	TTRIP	9	9.6707E-08	///L11*HP3	PDS24
IA	LOSP	1221	7.5888E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*VF5	PDS12
IA	LOSP	3865	7.3405E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	3835	7.0284E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P11*STF*T12*P31*T32*C13*C27	PDS4
IA	LOSP	1182	6.7213E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*STF*T12*P31*T32*SG1*SE1	PDS1
IA	LOSP	3656	6.4761E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	3618	6.2007E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*P31*T32*C13*C27	PDS4
IA	LOSP	3163	5.9177E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F*G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L1F*P21*HPF*FCF*LIF*CSF	PDS10
IA	LOSP	1385	5.6266E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F//P11*T11*L13*011	PDS24
IA	LOSP	1398	5.1141E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F//P11*T11*L13*P21*011	PDS24
IA	LOSP	2185	4.7661E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 2 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IA	LOSP	2641	4.4793E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A62*A2F*A3F//P11*T11*L13*P21*T21*SEF*SNF*O1F*FCF*RHF	PDS29
IA	LOSP	1223	3.5663E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F	PDS12
IA	RXTRIP	52	3.5583E-08	/A61//L12*O1F	PDS24
IA	CPI	5	3.5111E-08	///L11*O11	PDS24
IA	LOSP	2833	3.4793E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*P31*T32*SG1*DPF	PDS1
IA	LOSP	3868	3.4496E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P11*STF*T12*L13*P21*T22*SE1	PDS1
IA	LODC22	43	3.1776E-08	/D2F*G33//L11*O1F	PDS24
IA	LOSP	3660	3.0434E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*L13*P21*T22*SE1	PDS1
IA	LOSP	3959	2.6946E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*VF5*CF5	PDS21
IA	LOSP	3844	2.3416E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P11*STF*T12*P31*T32*SG1	PDS1
IA	LODC22	20	2.2441E-08	/D2F*A32//L12*O1F	PDS24
IA	LOSP	497	2.2437E-08	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1
IA	LOFW	52	2.2143E-08	/A61//L12*O1F	PDS24
IA	LODC22	27	2.1893E-08	/D2F*A62//L12*O1F	PDS24
IA	TTRIP	52	2.1724E-08	/A61//L12*O1F	PDS24
IA	LOSP	3117	2.1013E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F//P11*T11*L1F*HPF*FCF*LIF*CSF	PDS32B
IA	LOSP	3630	2.0658E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*P31*T32*SG1	PDS1
IA	LOSP	3124	1.9099E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F//P11*T11*L1F*P21*HPF*FCF*LIF*CSF	PDS32B
IA	LOSP	3667	1.8833E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*L13*P21*T22*VF5*CF5	PDS21
IA	LOSP	3873	1.8416E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P11*STF*T12*L13*P21*T22*VF5*CF5	PDS21
IA	LOSP	3956	1.8179E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*VF5	PDS12
IA	LODC22	70	1.7496E-08	/D2F*G22//L11*O1F	PDS24
IA	LODC21	63	1.7350E-08	/D1F*G12//L11*O1F	PDS24
IA	LODC21	40	1.7323E-08	/D1F*G2A//L11*O1F	PDS24
IA	LOSP	3168	1.6780E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F*G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L1F*P21*T22*VF5*CF5	PDS21
IA	LOSP	3166	1.6414E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F*G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L1F*P21*T22*VF5*FCF*LIF	PDS14
IA	LOSP	2835	1.6351E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*P31*T32*SG1*SE1*DPF	PDS1
IA	LOSP	463	1.6240E-08	/OGF*Y5F*Z6F*W2F*X3F/SC5*SBF*CCF/P11*STF*T12*L13*P21*T22*SEF*FCF	PDS1
IA	LOSP	2853	1.6050E-08	/OGF*Y5F*Z6F*W2F*X3F*D22*D33*D44*G2F*G3F*A6F*A2F*A3F//P11*T11*L13*O1F	PDS24
IA	L0693	4	1.5961E-08	/X3F//L11*O11	PDS24

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 3 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IA	LOSP	385	1.5850E-08	/OGF*Y5F*Z6F*W2F*X3F//P11*T11*L11*SEF*SN	PDS24
IA	LOSP	3022	1.5665E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*G23*G31*A6F*A2F *A3F//P11*T11*L1F*O1F	PDS24
IA	LOSP	2177	1.5203E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F *A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*P31 *T32*SG1	PDS1
IA	L0692	4	1.4814E-08	/W2F//L11*O11	PDS24
IA	LOSP	1817	1.4719E-08	/OGF*Y5F*Z6F*W2F*X3F*A62//P11*T11*L12*P2 1*T21*SEF*SNF*O1F	PDS24
IA	LOSP	2856	1.4588E-08	/OGF*Y5F*Z6F*W2F*X3F*D22*D33*D44*G2F*G3F *A6F*A2F*A3F//P11*T11*L13*P21*O1F	PDS24
IA	LOSP	1191	1.4445E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*O11	PDS1
IA	LOSP	390	1.4406E-08	/OGF*Y5F*Z6F*W2F*X3F//P11*T11*L11*P21*SE F*SNF*O11	PDS24
IA	LOSP	1513	1.4238E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*G23*G31*A6F*A2F *A3F//P11*T11*L1F*P21*O1F	PDS24
IA	LODC22	14	1.3342E-08	/D2F*FO3//L13*O1F*FCF	PDS24
IA	LOSP	3537	1.2664E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F//P1 1*T11*L12*P21*T21*SEF*SNF*O1F*FCF*RHF*CS	PDS32B
IA	LOSP	3871	1.2424E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*L13*P21*T22*VF5	PDS12
IA	RXTRIP	11	1.1971E-08	///L11*RW2	PDS32A
IA	LODC21	170	1.1945E-08	/W21*X32*D1F*D23*D34*G1F*G2F*G3F*A5F*A2F *A3F//L1F*HPF*FCF*LIF*CSF	PDS32B
IA	LODC21	155	1.1833E-08	/W21*D1F*D23*G13*G3F//L1F*O1F*FCF*CSF	PDS32
IA	LOSP	4100	1.1594E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*G31*A5F *A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12 *L13*P21*T22*DPF	PDS1
IA	LOSP	1492	1.1201E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F /SCA*SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	621	1.1109E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F/SCA *SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1
IA	LODC21	153	1.1081E-08	/W21*D1F*D23*G23//L1F*O1F*FCF*CSF	PDS32
IA	LODC21	152	1.1015E-08	/W21*D1F*D23*G32//L1F*O1F*FCF*CSF	PDS32
IA	LOSP	3663	1.0961E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*L13*P21*T22*VF5	PDS12
IA	LOSP	2432	1.0883E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A2F*A3F//P11*T1 1*L12*O11	PDS24
IA	LOSP	1960	1.0709E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F//P11*T11*L1 1*P21*T21*SEF*SNF*O1F	PDS24
IA	LOSP	3078	1.0549E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D33*D44*G1F*G2F *G31*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11 *STF*T12*L1F*O1F	PDS1
IA	LOSP	1448	1.0523E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F /CC3/P11*T11*L13*P21*T21*SEF*SNF*O1F*FCF *RHF	PDS29
IA	LOSP	1059	1.0442E-08	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F//P11*T11*L1 2*O11	PDS24
IA	LOSP	2450	9.8916E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A2F*A3F//P11*T1 1*L12*P21*O11	PDS24
IA	LOSP	3121	9.8748E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F //P11*T11*L1F*SE1*HPF*FCF*LIF*CSF	PDS32B

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 4 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IA	LOSP	3633	9.7081E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*P31*T32*SG1*SE1	PDS1
IA	RXTRIP	332	9.6682E-09	/Z61*X3F*G22*G32*A6F*A3F//L13*O1F	PDS24
IA	LODC22	8	9.6557E-09	/D2F/SC5/L13*O1F*FCF	PDS24
IA	LOSP	1077	9.4909E-09	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F//P11*T11*L12*P21*O11	PDS24
IA	MSLBOC	4	9.2910E-09	///L11*O11	PDS24
IA	LOSP	3128	8.9754E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F//P11*T11*L1F*P21*SE1*HPF*FCF*LIF*CSF	PDS32B
IA	MSIVC	6	8.7981E-09	///L11*HP3	PDS24
IA	LOSP	1283	8.5954E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F/CC3/P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	3958	8.5430E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*VF5*SE1	PDS12
IA	LOSP	2188	8.0816E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L13*P21*T22*VF5*CF5	PDS21
IA	LOSP	2187	8.0668E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L13*P21*T22*VF5	PDS12
IA	LOSP	1928	7.8029E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A52*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	3028	7.7974E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D33*D44*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*L13*O1F	PDS1
IA	LOSP	718	7.7305E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F*A22*FOF/SAF*SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	1896	7.5899E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F*FO1/SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	682	7.5687E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F*A32/SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	3089	7.5518E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23//P11*T11*L1F*P21*SEF*SNF*HPF*FCF*LIF*CSF	PDS32B
IA	LOSP	647	7.5276E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F*FO1/SBF*CCF/P11*STF*T12*L13*P21*T22	PDS1
IA	LOFW	11	7.4494E-09	///L11*RW2	PDS32A
IA	LOSP	2022	7.3637E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F//P11*PV7*T11*P21*T21*BV2*SEF*SNF*FC6*RHF	PDS30
IA	TTRIP	11	7.3085E-09	///L11*RW2	PDS32A
IA	LOSP	489	7.1571E-09	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF*T12*P31*T32*SG1	PDS1
IA	LOSP	1213	6.9620E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*DP1	PDS1
IA	LOSP	1197	6.7882E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*STF*T12*L13*SE1*O11	PDS1
IA	LOSP	3131	6.6683E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F//P11*T11*L1F*P21*T21*SEF*SNF*HPF*FCF*LI	PDS32B
IA	LOSP	207	6.6384E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*D43*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*L13*P21*T22*DPF	PDS1
IA	LOSP	1187	6.5067E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*STF*T12*P31*T32*SG1*VF3*CF3	PDS21
IA	LOFW	303	6.0165E-09	/Z61*X3F*G22*G32*A6F*A3F//L13*O1F	PDS24

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 5 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IA	LOSP	1410	6.0144E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F//P11*T11*L13*P21*T21*SEF*SNF*HP5*FCF*LIF	PDS29
IA	TTRIP	302	5.9027E-09	/Z61*X3F*G22*G32*A6F*A3F//L13*01F	PDS24
IA	LOCCW	7	5.9007E-09	//CCF/L11*HP3	PDS24
IA	LOSP	3081	5.8629E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D33*D44*G1F*G2F*G31*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L1F*P21*T22*DPF	PDS1
IA	LOSP	3872	5.8386E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P11*STF*T12*L13*P21*T22*VF5*SE1	PDS12
IA	LOSP	3625	5.5562E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*P31*T32*C13*C27*VF1	PDS13
IA	LOSP	409	5.5153E-09	/OGF*Y5F*Z6F*W2F*X3F//P11*ST4*T12*L13*P21*T22*SEF*SNF	PDS1
IA	LODC22	111	5.5459E-09	/D11*D2F//L1F*O1F*FCF*CSF	PDS32
IA	LODC21	103	5.5442E-09	/D1F*D21//L1F*O1F*FCF*CSF	PDS32
IA	LOSP	541	5.3226E-09	/OGF*Y5F*Z6F*W2F*X3F*A32//P11*ST5*T12*L13*P21*T22*SEF*COF	PDS1
IA	LODC22	37	5.3106E-09	/D2F*A62*A32//L13*O1F	PDS24
IA	LOSP	456	5.1803E-09	/OGF*Y5F*Z6F*W2F*X3F/SC5*SBF*CCF/P11*STF*T12*P31*T32*SG1*SEF*FCF	PDS1
IA	LOSP	3665	5.1511E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*L13*P21*T22*VF5*SE1	PDS12
IA	LOSP	2442	5.1143E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A2F*A3F//P11*T11*L12*SE1*O11	PDS24
IA	LOSP	958	5.1138E-09	/OGF*Y5F*Z6F*W2F*X3F*A52*A32//P11*STF*T12*L13*P21*T22	PDS1
IA	LOSP	3662	5.0410E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*L13*P21*T22*SE1*CO1	PDS1
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IB	LOCCW	3	1.9188E-07	//CCF/L11*HRG*CSF	PDS34
IB	RXTRIP	3	1.6006E-07	///L11*HRA*CSF	PDS34
IB	LOFW	3	9.9602E-08	///L11*HRA*CSF	PDS34
IB	TTRIP	3	9.7718E-08	///L11*HRA*CSF	PDS34
IB	MSIVC	3	8.8901E-09	///L11*HRA*CSF	PDS34

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 6 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IIA	SLOCA	77	5.2955E-07	//EA1*EBC/HPF*L1F*FCF*LIF*CSF	PDS46
IIA	LOSP	1211	4.4837E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22	PDS1
IIA	LOSP	1162	4.2930E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27	PDS4
IIA	LOSP	1167	2.0175E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27*SE1	PDS4
IIA	LOSP	1177	1.4302E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*SG1	PDS1
IIA	LOSP	2824	1.0444E-07	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*P31*T32*C13*C27*DPF	PDS4
IIA	LOSP	1176	5.7019E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27*VF1*CF1	PDS23
IIA	LOSP	2173	4.5634E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F *A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*P31 *T32*C13*C27	PDS4
IIA	LOSP	1172	3.8468E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27*VF1	PDS13
IIA	LOSP	3838	3.3029E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*P31*T32*C13*C27*SE1	PDS4
IIA	LOSP	1232	2.9436E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*PV7*STF*T12*P21*T22	PDS4
IIA	LOSP	3622	2.9140E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*P31*T32*C13*C27*SE1	PDS4
IIA	LOSP	485	2.1483E-08	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*P31*T32*C13*C27	PDS4
IIA	LOSP	1174	1.8077E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27*VF1*SE1	PDS13
IIA	LOSP	452	1.5549E-08	/OGF*Y5F*Z6F*W2F*X3F/SC5*SBF*CCF/P11*STF *T12*P31*T32*C13*C27*SEF*FCF	PDS4
IIA	LOSP	1235	1.3833E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F	PDS4
IIA	LOSP	2832	1.3659E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*P31*T32*C13*C27*VF1*CF 1	PDS23
IIA	LOSP	739	1.1288E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*HP3	PDS4
IIA	LOSP	4090	1.1101E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*G31*A5F *A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12 *P31*T32*C13*C27*DPF	PDS4
IIA	LOSP	3658	1.0727E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*L13*P21*T22*CO1	PDS1
IIA	LOSP	3620	1.0271E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*P31*T32*C13*C27*CO1	PDS4
IIA	LOSP	1239	9.9534E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*PV7*STF*T12*P21*T22*VF7*CF7	PDS23
IIA	LOSP	3629	9.5465E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*P31*T32*C13*C27*VF1*CF1	PDS23
IIA	LOSP	3843	9.3350E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1	PDS23
IIA	LOSP	2830	9.2149E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*P31*T32*C13*C27*VF1	PDS13
IIA	LOSP	1268	8.2299E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F /CC3/P11*STF*T12*P31*T32*C13*C27	PDS4

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 7 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IIA	LOSP	1920	7.4711E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A52*A6F*A2F *A3F*FOF/SAF*SBF*CCF/P11*STF*T12*P31*T32 *C13*C27	PDS4
IIA	LOSP	710	7.4018E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F*A22 *FOF/SAF*SBF*CCF/P11*STF*T12*P31*T32*C13 *C27	PDS4
IIA	LOSP	1510	7.2671E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F *FO1/SBF*CCF/P11*STF*T12*P31*T32*C13*C27	PDS4
IIA	LOSP	673	7.2468E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F*A32 /SBF*CCF/P11*STF*T12*P31*T32*C13*C27	PDS4
IIA	LOSP	639	7.2075E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F*FO1 /SBF*CCF/P11*STF*T12*P31*T32*C13*C27	PDS4
IIA	LOSP	3963	7.1608E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*PV7*STF*T12*P21*T22*DPF	PDS4
IIA	LOSP	1237	6.7150E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*PV7*STF*T12*P21*T22*VF7	PDS13
IIA	LOSP	1164	6.6659E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27*DP1	PDS4
IIA	LOSP	195	6.3561E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*D43*G1F*G2F*A5F *A2F*A3F//P11*STF*T12*P31*T32*C13*C27*DP F	PDS4
IIA	LOSP	3841	6.2978E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*P31*T32*C13*C27*VF1	PDS13
IIA	LOSP	749	5.3047E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*SE1*HP3	PDS4
IIA	LOSP	402	5.2807E-09	/OGF*Y5F*Z6F*W2F*X3F//P11*ST4*T12*P31*T3 2*C13*C27*SEF*SNF	PDS4
IIA	LOSP	530	5.0963E-09	/OGF*Y5F*Z6F*W2F*X3F*A32//P11*ST5*T12*P3 1*T32*C13*C27*SEF*COF	PDS4
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IIB	LOSP	2828	4.9078E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*P31*T32*C13*C27*SE1*DP F	PDS4
IIB	LOSP	3546	4.2306E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F//P1 1*PV7*T11*P21*T21*BVF*SEF*SNF*FCF*RHF*CS F	PDS33B
IIB	LOSP	1421	1.9210E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F //P11*PV7*T11*P21*T21*BV2*SEF*SNF*FCF*RH F	PDS30
IIB	LOSP	736	1.1614E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*HRA*CSF	PDS9
IIB	LOCCW	11	6.0964E-09	//CCF/PV1*HRG*CSF	PDS33A
IIB	LOSW	3	5.7817E-09	//SBF*CCF/L11*HRG*CSF	PDS34
IIB	LOSP	747	5.4578E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*SE1*HRA*CSF	PDS9
IIB	RXTRIP	13	5.0854E-09	///PV1*HRA*CSF	PDS33A

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 8 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IIIA	SLOCA	24	8.8700E-07	///RW2	PDS45
IIIA	SLOCA	18	7.9447E-07	///HP3*Y11	PDS41
IIIA	SLOCA	12	3.0787E-08	///L11*O11	PDS41
IIIA	SLOCA	16	1.2866E-08	///HP3*LP1	PDS42
IIIA	SLOCA	70	9.7115E-09	//EA1/HPD*Y11	PDS41
IIIA	SLOCA	53	9.7107E-09	//EB1/HPD*Y11	PDS41
IIIA	SLOCA	72	7.7844E-09	//EA1/RW2	PDS45
IIIA	SLOCA	55	7.7837E-09	//EB1/RW2	PDS45
IIIB	SLOCA	2	3.2058E-06	///LR6*CSF	PDS45
IIIB	SLOCA	26	3.7877E-08	//CC1/LRC*CSF	PDS45
IIIB	SLOCA	61	2.8126E-08	//EA1/LR6*CSF	PDS45
IIIB	SLOCA	44	2.8123E-08	//EB1/LR6*CSF	PDS45
IIIB	SLOCA	6	1.8253E-08	///DZ1*HRA*CSF	PDS45
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IIIC	MLOCA	11	5.0485E-07	///AS1	PDS41
IIIC	BECCSL	1	2.9335E-07	///	PDS36
IIIC	LLOCA	8	2.3198E-07	///LP1	PDS36
IIIC	LLOCA	6	2.2240E-07	///AS1	PDS35
IIIC	LLOCA	30	2.6625E-08	//EA1/LP4	PDS36
IIIC	LLOCA	22	2.6623E-08	//EB1/LP4	PDS36
IIIC	MLOCA	19	2.3466E-08	///RW1	PDS45
IIIC	MLOCA	15	2.1284E-08	///HP3*Y11	PDS41
IIIC	SLOCA	17	1.2463E-08	///HP3*AS1	PDS41
IIIC	LLOCA	10	1.0277E-08	///RW1	PDS39
IIIC	MLOCA	12	7.8391E-09	///AS1*DP1	PDS41
IIIC	LLOCA	33	6.3422E-09	//EA1*EBC/LPF*FCF*CSF	PDS40
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IIID	LLOCA	3	1.8397E-06	///LR1*CSF	PDS39
IIID	MLOCA	5	1.2152E-06	///DZ2*HR1*CSF	PDS45
IIID	LLOCA	2	1.3270E-07	///RC1	PDS35
IIID	MLOCA	2	5.5253E-08	///LR6*CSF	PDS45
IIID	MLOCA	6	1.8870E-08	///DZ2*HR1*DP1*CSF	PDS45
IIID	LLOCA	27	1.5915E-08	//EA1/LR1*CSF	PDS39
IIID	LLOCA	19	1.5914E-08	//EB1/LR1*CSF	PDS39
IIID	LLOCA	11	1.4742E-08	//CC1/RCF	PDS35
IIID	MLOCA	47	1.0663E-08	//EA1/DZ2*FCF*HR1*CSF	PDS46
IIID	MLOCA	33	1.0662E-08	//EB1/DZ2*FCF*HR1*CSF	PDS46
IIID	LLOCA	12	5.6178E-09	//CC1/LRA*CSF	PDS39

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 9 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IV	TTRIPA	20	1.4406E-07	///RT1*PL1*L1A	PDS24
IV	TTRIPA	12	1.0399E-07	///RT1*PL1*BR1*MD2	PDS24
IV	LOSPA	180	9.1380E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A2F*A3F//RT1*PL1*L1F	PDS24
IV	LOSPA	128	8.7375E-08	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F//RT1*PL1*L1F	PDS24
IV	LOCCWA	8	8.5468E-08	//CCF/RT1*PL1*BRF*MD2*LRF*CSF	PDS32A
IV	LOFWA	19	8.2527E-08	///RT1*PL1*PR2	PDS26
IV	TTRIPA	19	8.0966E-08	///RT1*PL1*PR2	PDS26
IV	LOSPA	16	6.1213E-08	/OGF*Y5F*Z6F*W2F*X3F//RT1*PL1*L1A	PDS24
IV	LOFWA	4	5.8917E-08	///RT1*BR1*MD2	PDS24
IV	TTRIPA	4	5.7803E-08	///RT1*BR1*MD2	PDS24
IV	LOCCWA	3	4.7508E-08	//CCF/RT1*BRF*MD2*LRF*CSF	PDS32A
IV	LOSPA	10	4.4187E-08	/OGF*Y5F*Z6F*W2F*X3F//RT1*PL1*BR1*MD2	PDS24
IV	LOFWA	18	4.2549E-08	///RT1*PL1*SR1*O21	PDS26
IV	TTRIPA	18	4.1744E-08	///RT1*PL1*SR1*O21	PDS26
IV	LOSPA	229	3.7811E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F//RT1*PL1*BRF*MD2	PDS24
IV	LOSPA	15	3.4405E-08	/OGF*Y5F*Z6F*W2F*X3F//RT1*PL1*PR2	PDS26
IV	LOFWA	22	3.2041E-08	///RT1*PL1*TT1	PDS26
IV	TTRIPA	22	3.1435E-08	///RT1*PL1*TT1	PDS26
IV	LOSPA	4	2.4562E-08	/OGF*Y5F*Z6F*W2F*X3F//RT1*BR1*MD2	PDS24
IV	LOFWA	8	2.3651E-08	///RT1*SR1*O21	PDS26
IV	TTRIPA	8	2.3204E-08	///RT1*SR1*O21	PDS26
IV	LOSPA	223	2.1980E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F//RT1*BRF*MD2	PDS24
IV	LOSPA	122	2.1039E-08	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F//RT1*BRF*MD2	PDS24
IV	LOSPA	14	1.7738E-08	/OGF*Y5F*Z6F*W2F*X3F//RT1*PL1*SR1*O21	PDS26
IV	LOSPA	17	1.3357E-08	/OGF*Y5F*Z6F*W2F*X3F//RT1*PL1*TT1	PDS26
IV	MSIVCA	15	1.3106E-08	///RT1*PL1*L1A	PDS24
IV	LOSPA	232	1.1660E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F//RT1*PL1*SR2*O2F	PDS26
IV	LOSPA	7	9.8601E-09	/OGF*Y5F*Z6F*W2F*X3F//RT1*SR1*O21	PDS26
IV	MSIVCA	10	9.4605E-09	///RT1*PL1*BR1*MD2	PDS24
IV	LOCCWA	14	8.9913E-09	//CCF/RT1*PL1*L1A*LRF*CSF	PDS32A
IV	MSIVCA	14	7.3661E-09	///RT1*PL1*PR2	PDS26
IV	LOSPA	28	7.3198E-09	/OGF*Y5F*Z6F*W2F*X3F*A32//RT1*PL1*L1F	PDS24
IV	LOSPA	58	7.1306E-09	/OGF*Y5F*Z6F*W2F*X3F*A62//RT1*PL1*L1F	PDS24
IV	LOSPA	225	6.7783E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F//RT1*SR2*O2F	PDS26
IV	LOSPA	125	6.4881E-09	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F//RT1*SR2*O2F	PDS26
IV	LOPFA	14	6.2865E-09	///RT1*PL1*L1A	PDS24
IV	LOSPA	234	6.2674E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F//RT1*PL1*PR3	PDS26
IV	LOSPA	283	6.2456E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F//RT1*PL1*L1F*FCF*LIF*CSF	PDS32B
IV	LOSPA	212	6.2118E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F//RT1*PL1*L1F*FCF*LIF	PDS29

TABLE 3.4-2: IP2 Accident Sequences Which Contribute to the Upper 95% of the IP2 Core Damage Frequency Ordered by Functional Sequence Group (Page 10 of 10)

Functional Sequence Group	Initiating Event	Sequence No.	Frequency	Failed Split Fractions	Plant Damage State
IV	MSIVCA	4	5.2587E-09	///RT1*BR1*MD2	PDS24
IV	LOCCWA	13	5.0536E-09	//CCF/RT1*PL1*PR2*LRF*CSF F*T12*L13*P21*T22*SE1*CO1	PDS33A
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VA	VSEQ	2	2.6716E-08	//EAF*EBF/VSQ	PDS47
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VB	SGTR	11	2.2253E-07	///OS1*SO1*LR4	PDS48A
VB	SGTR	12	4.7929E-08	///OS1*SO1*MU1	PDS48A
VB	SGTR	14	2.6044E-08	///OS1*O5E*SO3	PDS48A
VB	SGTR	29	2.2174E-08	///HP3*OS1*SO1	PDS48A
VB	SGTR	18	1.4964E-08	///L11*O31	PDS48A
VB	SGTR	37	1.3421E-08	///RW2*OS1	PDS48A
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VC	SGTR	6	4.9328E-07	///O41*O5A	PDS48B
VC	SGTR	113	4.0521E-07	//EA1*EBC/HPF*L1F	PDS48B
VC	SGTR	13	1.6504E-07	///OS1*O5E	PDS48B
VC	SGTR	23	9.8181E-08	///HP3*O41*O5G	PDS48B
VC	SGTR	33	4.3822E-08	///HP3*L14	PDS48B
VC	SGTR	16	1.2264E-08	///L11*LR1	PDS48B
VC	SGTR	36	1.0071E-08	///RW2*O41	PDS48B

TABLE 3.4-3: **IP2 IPE Sequences that Contribute to Containment Bypass Frequency in excess of 1.0E-08 per year (ie.Type 1 Release).**

	Frequency per year	Sequence Description	Plant Damage State
1.	1.891E-07	SGTR*OS1*SO1*LR4	PDS48A
2.	4.938E-08	SGTR*OS1*SO1*MU1	PDS48A
3.	1.955E-08	SGTR*OS1*O5E*SO3	PDS48A
4.	2.6716E-08	VSQ	PDS47
5.	2.345E-08	SGTR*HP3*OS1*SO1	PDS48A
6.	1.509E-08	SGTR*L11*O31	PDS48A
7.	1.653E-08	SGTR*RW2*OS1	PDS48A
	3.645E-07	TOTAL	

TABLE 3.4-4: Plant Damage States that Contribute Containment Failure Frequency with Release >= WASH 1400 PWR-4 Release Category

Contribution to Type I Releases

Plant Damage State[(2)] Level 1 Designation	Level 2 Designation	% Contribution		Frequency[(1)] (per year)
PDS48A	PDS31	93.1		3.725E-07
PDS47	PDS29	6.9		2.772E-08
			Total	3.997E-07

Contribution to SGTR Type II (SGTR) Releases

Plant Damage State[(2)] Level 1 Designation	Level 2 Designation	% Contribution		Frequency[(1)] (per year)
PDS48B	PDS30	81.0		1.250E-06
PDS24	PDS11	14.3		2.218E-07
PDS1, 2 & 7	PDS1	2.2		3.403E-08
PDS25 & 27	PDS13	0.7		1.140E-08
			Total	1.543E-06

TABLE 3.4-4 (cont): Plant Damage States that Contribute Containment Failure Frequency with Release >= WASH 1400 PWR-4 Release Category

Contribution to Type II (Containment Failure) Releases

Plant Damage State[2] Level 1 Designation	Plant Damage State[2] Level 2 Designation	% Contribution		Frequency[1] (per year)
PDS46, 40 & 43	PDS28	24.9		4.677E-07
PDS45 & 44	PDS27	23.9		4.478E-07
PDS21 & 22	PDS9	12.7		2.377E-07
PDS10 & 11	PDS5	11.9		2.237E-07
PDS32B	PDS20	7.5		1.424E-07
PDS23	PDS10	5.6		1.048E-07
PDS34	PDS19	2.5		4.696E-08
PDS33B & 34B	PDS21	2.2		4.212E-08
PDS29,25 & 27	PDS13	1.1		2.150E-08
PDS13	PDS7	0.7		1.491E-08
PDS4	PDS2	0.6		1.151E-08
PDS41	PDS25	0.6		1.126E-08
PDS32	PDS16	0.3		4.618E-09
		(94.5)	Total	1.877E-06

Note (1): This is the frequency at which the release type would be expected to occur stemming from the CET path(s) associated with the particular PDS.

Note (2): in the Level II Analysis the Level I plant damage states were collapsed and renumbered. Unless otherwise stated any reference to a plant damage state refers to the Level I designation.

TABLE 3.4-5: Listing of Core Damage Sequences which Contribute to Plant Damage States leading to Containment Failure

Note 1% of plant damage state frequency is used as a cut off for listing sequences

Significant Sequences for Plant Damage State: PDS1
Total PDS Frequency: 1.8815E-06 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	1211	4.4837E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22
LOSP	1216	2.1070E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22*SE1
LOSP	1177	1.4302E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*SG1
LOSP	3950	1.0907E-07	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*L13*P21*T22*DPF
LOSP	3865	7.3405E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*L13*P21*T22
LOSP	1182	6.7213E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*SG1*SE1
LOSP	3656	6.4761E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*L13*P21*T22
LOSP	3954	5.1258E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*L13*P21*T22*SE1*DPF
LOSP	2185	4.7661E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F *A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L13 *P21*T22
LOSP	2833	3.4793E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*P31*T32*SG1*DPF
LOSP	3868	3.4496E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*L13*P21*T22*SE1
LOSP	3660	3.0434E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*L13*P21*T22*SE1
LOSP	3844	2.3416E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*P31*T32*SG1
LOSP	497	2.2437E-08	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*L13*P21*T22
LOSP	3630	2.0658E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*P31*T32*SG1

Significant Sequences for Plant Damage State: PDS5
Total PDS Frequency: 9.8483E-08 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	3164	9.8483E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F *G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF /P11*STF*T12*L1F*P21*T22*FCF*DPF*LIF

TABLE 3.4-5 (cont): Listing of Core Damage Sequences That Contribute to Containment Failure Plant Damage States

Significant Sequences for Plant Damage State: PDS10
Total PDS Frequency: 2.3987E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	3162	1.7851E-07	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F *G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF /P11*STF*T12*L1F*HPF*FCF*LIF*CSF
LOSP	3163	5.9177E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F *G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF /P11*STF*T12*L1F*P21*HPF*FCF*LIF*CSF

Significant Sequences for Plant Damage State: PDS12
Total PDS Frequency: 2.3559E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	1221	7.5888E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22*VF5
LOSP	1223	3.5663E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22*VF5*SE1
LOSP	3956	1.8179E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*L13*P21*T22*VF5
LOSP	3871	1.2424E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*L13*P21*T22*VF5
LOSP	3663	1.0961E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*L13*P21*T22*VF5
LOSP	3958	8.5430E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*L13*P21*T22*VF5*SE1
LOSP	2187	8.0668E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F *A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L13 *P21*T22*VF5
LOSP	3872	5.8386E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*L13*P21*T22*VF5*SE1
LOSP	3665	5.1511E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*L13*P21*T22*VF5*SE1
LOSP	1185	4.3897E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*SG1*VF3
LOSP	499	3.7975E-09	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*L13*P21*T22*VF5
LOSP	465	2.7487E-09	/OGF*Y5F*Z6F*W2F*X3F/SC5*SBF*CCF/P11*STF *T12*L13*P21*T22*VF5*SEF*FCF

TABLE 3.4-5 (cont): Listing of Core Damage Sequences That Contribute to Containment Failure Plant Damage States

Significant Sequences for Plant Damage State: PDS13
Total PDS Frequency: 1.3005E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	1172	3.8468E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27*VF1
LOSP	1174	1.8077E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*C13*C27*VF1*SE1
LOSP	2830	9.2149E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*P31*T32*C13*C27*VF1
LOSP	1237	6.7150E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*PV7*STF*T12*P21*T22*VF7
LOSP	3841	6.2978E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*P31*T32*C13*C27*VF1
LOSP	3625	5.5562E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*P31*T32*C13*C27*VF1
LOSP	2831	4.3305E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*P31*T32*C13*C27*VF1*SE 1
LOSP	2175	4.0891E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F *A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*P31 *T32*C13*C27*VF1
LOSP	1238	3.1556E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*PV7*STF*T12*P21*T22*VF7*SE1
LOSP	3842	2.9596E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*P31*T32*C13*C27*VF1*SE1
LOSP	3627	2.6111E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*P31*T32*C13*C27*VF1*SE1
LOSP	487	1.9250E-09	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*P31*T32*C13*C27*VF1
LOSP	3965	1.6086E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*PV7*STF*T12*P21*T22*VF7
LOSP	454	1.3933E-09	/OGF*Y5F*Z6F*W2F*X3F/SC5*SBF*CCF/P11*STF *T12*P31*T32*C13*C27*VF1*SEF*FCF

Significant Sequences for Plant Damage State: PDS21
Total PDS Frequency: 2.5492E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	1225	1.1249E-07	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*L13*P21*T22*VF5*CF5
LOSP	3959	2.6946E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F *A3F//P11*STF*T12*L13*P21*T22*VF5*CF5
LOSP	3667	1.8833E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*ST F*T12*L13*P21*T22*VF5*CF5
LOSP	3873	1.8416E-08	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P1 1*STF*T12*L13*P21*T22*VF5*CF5
LOSP	3168	1.6780E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D34*D45*G1F *G2F*G3F*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF /P11*STF*T12*L1F*P21*T22*VF5*CF5
LOSP	2188	8.0816E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F *A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*L13 *P21*T22*VF5*CF5
LOSP	1187	6.5067E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*P31*T32*SG1*VF3*CF3
LOSP	500	3.8045E-09	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*L13*P21*T22*VF5*CF5
LOSP	466	2.7534E-09	/OGF*Y5F*Z6F*W2F*X3F/SC5*SBF*CCF/P11*STF *T12*L13*P21*T22*VF5*CF5

TABLE 3.4-5 (cont): Listing of Core Damage Sequences That Contribute to Containment Failure Plant Damage States

Significant Sequences for Plant Damage State: PDS23
Total PDS Frequency: 1.3130E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	1176	5.7019E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*STF*T12*P31*T32*C13*C27*VF1*CF1
LOSP	2832	1.3659E-08	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F*A3F//P11*STF*T12*P31*T32*C13*C27*VF1*CF1
LOSP	1239	9.9534E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F//P11*PV7*STF*T12*P21*T22*VF7*CF7
LOSP	3629	9.5465E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*STF*T12*P31*T32*C13*C27*VF1*CF1
LOSP	3843	9.3350E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P11*STF*T12*P31*T32*C13*C27*VF1*CF1
LOSP	2176	4.0966E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*G31*A5F*A6F*A2F*A3F*FOF/SAF*SBF*CCF/P11*STF*T12*P31*T32*C13*C27*VF1*CF1
LOSP	3967	2.3843E-09	/OGF*Y5F*Z6F*W2F*X3F*D32*G1F*G2F*A5F*A2F*A3F//P11*PV7*STF*T12*P21*T22*VF7*CF7
LOSP	488	1.9285E-09	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF*T12*P31*T32*C13*C27*VF1*CF1
LOSP	3678	1.6665E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*A32//P11*PV7*STF*T12*P21*T22*VF7*CF7
LOSP	3881	1.6295E-09	/OGF*Y5F*Z6F*W2F*X3F*G23*A52*A2F*A3F//P11*PV7*STF*T12*P21*T22*VF7*CF7
LOSP	455	1.3957E-09	/OGF*Y5F*Z6F*W2F*X3F/SC5*SBF*CCF/P11*STF*T12*P31*T32*C13*C27*VF1*CF1

Significant Sequences for Plant Damage State: PDS24
Total PDS Frequency: 1.2323E-05 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
RXTRIP	5	3.9718E-06	///L11*O11
LOFW	5	2.4716E-06	///L11*O11
TTRIP	5	2.4249E-06	///L11*O11
LODC21	2	2.4447E-07	/D1F//L11*O1F
LODC22	2	2.2997E-07	/D2F//L11*O1F
MSIVC	5	2.2061E-07	///L11*O11
LOSP	1092	1.8031E-07	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F//P11*T11*L12*P21*T21*SEF*SNF*O1F
RXTRIP	9	1.5840E-07	///L11*HP3
LOCCW	5	1.4796E-07	//CCF/L11*O11
LOFWA	20	1.4683E-07	///RT1*PL1*L1A
TTRIPA	20	1.4406E-07	///RT1*PL1*L1A

Significant Sequences for Plant Damage State: PDS29
Total PDS Frequency: 6.2788E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	1407	5.4893E-07	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F//P11*T11*L13*P21*T21*SEF*SNF*O1F*FCF*RHF

TABLE 3.4-5 (cont): Listing of Core Damage Sequences That Contribute to Containment Failure Plant Damage States

Significant Sequences for Plant Damage State: PDS32B
Total PDS Frequency: 1.5368E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
LOSP	3117	2.1013E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F //P11*T11*L1F*HPF*FCF*LIF*CSF
LOSP	3124	1.9099E-08	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F //P11*T11*L1F*P21*HPF*FCF*LIF*CSF
LOSP	3537	1.2664E-08	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F//P1 1*T11*L12*P21*T21*SEF*SNF*O1F*FCF*RHF*CS F
LODC21	170	1.1945E-08	/W21*X32*D1F*D23*D34*G1F*G2F*G3F*A5F*A2F *A3F//L1F*HPF*FCF*LIF*CSF
LOSP	3121	9.8748E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F //P11*T11*L1F*SE1*HPF*FCF*LIF*CSF
LOSP	3128	8.9754E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F //P11*T11*L1F*P21*SE1*HPF*FCF*LIF*CSF
LOSP	3088	8.3086E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23//P11*T11*L1 F*SEF*SNF*HPF*FCF*LIF*CSF
LOSP	3089	7.5518E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23//P11*T11*L1 F*P21*SEF*SNF*HPF*FCF*LIF*CSF
LOSP	3131	6.6683E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F //P11*T11*L1F*P21*T21*SEF*SNF*HPF*FCF*LI F*CSF
LOSPA	283	6.2456E-09	/OGF*Y5F*Z6F*W2F*X3F*G13*G31*A5F*A6F//RT 1*PL1*L1F*FCF*LIF*CSF
LOSP	3118	3.4805E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F //P11*T11*L1F*CO1*HPF*FCF*LIF*CSF
LOSP	3125	3.1635E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G3F*A6F //P11*T11*L1F*P21*CO1*HPF*FCF*LIF*CSF
LOSP	3147	2.6242E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G23*G3F *A6F*A2F*A3F//P11*T11*L1F*HPF*FCF*LIF*CS F
LOSP	3154	2.5853E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G12*G3F *A5F*A6F//P11*T11*L1F*HPF*FCF*LIF*CSF
LOSP	3148	2.3852E-09	/OGF*Y5F*Z6F*W2F*X3F*D12*D23*D44*G23*G3F *A6F*A2F*A3F//P11*T11*L1F*P21*HPF*FCF*LI F*CSF

Significant Sequences for Plant Damage State: PDS45
Total PDS Frequency: 5.5624E-06 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
SLOCA	2	3.2058E-06	///LR6*CSF
MLOCA	5	1.2152E-06	///DZ2*HR1*CSF
SLOCA	24	8.8700E-07	///RW2

TABLE 3.4-5 (cont): Listing of Core Damage Sequences That Contribute to Containment Failure Plant Damage States

Significant Sequences for Plant Damage State: PDS46
Total PDS Frequency: 5.7130E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
SLOCA	77	5.2955E-07	//EA1*EBC/HPF*L1F*FCF*LIF*CSF
MLOCA	58	1.4465E-08	//EA1*EBC/HPF*L1F*FCF*LIF*CSF
MLOCA	47	1.0663E-08	//EA1/DZ2*FCF*HR1*CSF
MLOCA	33	1.0662E-08	//EB1/DZ2*FCF*HR1*CSF

Significant Sequences for Plant Damage State: PDS48A
Total PDS Frequency: 3.7247E-07 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
SGTR	11	2.2253E-07	///OS1*SO1*LR4
SGTR	12	4.7929E-08	///OS1*SO1*MU1
SGTR	14	2.6044E-08	///OS1*O5E*SO3
SGTR	29	2.2174E-08	///HP3*OS1*SO1
SGTR	18	1.4964E-08	///L11*O31
SGTR	37	1.3421E-08	///RW2*OS1
SGTR	4	4.6321E-09	///O41*SO2*LR4

Significant Sequences for Plant Damage State: PDS48B
Total PDS Frequency: 1.2502-06 per yr

Initiator.	Index....	Frequency......	Failed Split Fractions.................
SGTR	6	4.9328E-07	///O41*O5A
SGTR	113	4.0521E-07	//EA1*EBC/HPF*L1F
SGTR	13	1.6504E-07	///OS1*O5E
SGTR	23	9.8181E-08	///HP3*O41*O5G
SGTR	33	4.3822E-08	///HP3*L14

TABLE 3.4-6: Top 50 Sequences from HRA sensitivity study which did not make screening criteria in base case study

Initiator.	Index....	Frequency......	Failed Split Fractions.................	End State
LOSP	306	1.5220E-04	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*HRA*CSF	PDS9
SGTR	15	1.3040E-04	///OS1*O5E*SO3	PDS48A
LOSP	1751	4.5440E-05	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*L13*P21*T22	PDS1
LOFW	3	4.4259E-05	///L11*HRA*CSF	PDS34
TTRIP	3	4.3422E-05	///L11*HRA*CSF	PDS34
LODC22	20	2.9926E-05	/D2F*F03//L13*O1F*FCF	PDS24
LOSP	340	1.9960E-05	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*P31*HRA*CSF	PDS9
RXTRIP	18	1.9413E-05	///PV1*HRA*CSF	PDS33A
LOSP	307	1.9042E-05	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*HRA*DP1*CSF	PDS9
LOSP	1723	1.8958E-05	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*L13*HRA*CSF	PDS9
LOSP	369	1.7563E-05	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*P31*T32*C13*C27	PDS4
LOFW	18	1.2081E-05	///PV1*HRA*CSF	PDS33A
TTRIP	18	1.1852E-05	///PV1*HRA*CSF	PDS33A
LOSP	1960	1.0956E-05	/OGF*Y5F*Z6F*W2F*X3F*G23*A2F*A3F*F02/SBF *CCF/P11*STF*T12*HRA*CSF	PDS9
LOSP	1726	1.0042E-05	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*L13*O11	PDS1
LOSP	1763	8.5209E-06	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*L13*P21*T22*VF5	PDS12
LOSP	1709	5.8511E-06	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*P31*T32*SG1	PDS1
LOSP	1753	5.6286E-06	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*L13*P21*T22*LR6*CSF	PDS7
LOSP	1752	5.0489E-06	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*L13*P21*T22*CS4	PDS7
RXTRIP	8	4.6662E-06	///L11*O11*LR6*CSF	PDS32A
RXTRIP	7	4.1856E-06	///L11*O11*CS4	PDS32
MSIVC	3	3.9504E-06	///L11*HRA*CSF	PDS34
LODC22	24	3.8064E-06	/D2F*F03//L13*O1F*FCF*LR8*CSF	PDS32B
LODC22	21	3.3843E-06	/D2F*F03//L13*O1F*FCF*CS5	PDS32
LOSP	1742	3.3288E-06	/OGF*Y5F*Z6F*W2F*X3F*F03/SBF*CCF/P11*STF *T12*L13*P21*O11	PDS1
LOSP	2025	3.2709E-06	/OGF*Y5F*Z6F*W2F*X3F*G23*A2F*A3F*F02/SBF *CCF/P11*STF*T12*L13*P21*T22	PDS1
LOFW	8	2.9038E-06	///L11*O11*LR6*CSF	PDS32A
TTRIP	8	2.8488E-06	///L11*O11*LR6*CSF	PDS32A
LOFW	7	2.6047E-06	///L11*O11*CS4	PDS32

TABLE 3.4-6 (cont'd): Top 50 Sequences from HRA sensitivity study which did not make screening criteria in base case study

TTRIP	7	2.5554E-06	///L11*O11*CS4	PDS32
LOSP	3711	2.1924E-06	/OGF*Y5F*Z6F*W2F*X3F*G13*G2C*A5F*A2F*A3F //P11*STF*T12*HRA*CSF	PDS9
LOSP	371	2.1754E-06	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*P31*T32*C13*C27*LR6*CSF	PDS9
LOSP	1708	2.1564E-06	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*P31*T32*C13*C27*VF1*CF1	PDS23
MSIVC	6	2.0924E-06	///L11*O11	PDS24
LOSP	370	1.9514E-06	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*P31*T32*C13*C27*CS4	PDS9
LOPF	3	1.8947E-06	///L11*HRA*CSF	PDS34
LOCCWA	10	1.0854E-06	//CCF/RT1*PL1*BRF*MD2*LRF*CSF	PDS32A
LOSP	1704	1.7435E-06	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*P31*T32*C13*C27*VF1	PDS13
LOSP	1980	1.4367E-06	/OGF*Y5F*Z6F*W2F*X3F*G23*A2F*A3F*FO2/SBF *CCF/P11*STF*T12*P31*HRA*CSF	PDS9
LOSP	1061	1.3535E-06	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*FO2/SBF*CCF /P11*STF*T12*L13*HRA*CSF	PDS9
LOPF	14	1.2931E-06	///PV4*HRA*CSF	PDS33A
LOCCW	5	1.2651E-06	//CCF/L11*O11	PDS24
LOSP	1990	1.2642E-06	/OGF*Y5F*Z6F*W2F*X3F*G23*A2F*A3F*FO2/SBF *CCF/P11*STF*T12*P31*T32*C13*C27	PDS4
LOSP	1038	1.2538E-06	/OGF*Y5F*Z6F*W2F*X3F*G13*A5F*FO2/SBF*CCF /P11*STF*T12*P31*T32*C13*C27	PDS4
LOSP	1728	1.2438E-06	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*L13*O11*LR6*CSF	PDS7
LOSP	4402	1.2132E-06	/OGF*Y5F*Z6F*W2F*X3F*G31*A6F*FO2/SBF*CCF /P11*STF*T12*P31*T32*C13*C27	PDS4
LOSP	1786	1.1766E-06	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*PV7 *STF*T12*P21*T22	PDS4
LOSP	1727	1.1157E-06	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*L13*O11*CS4	PDS7
MSIVC	15	1.0783E-06	///PV1*HRA*CSF	PDS33A
LOSP	2901	1.0638E-06	/OGF*Y5F*Z6F*W2F*X3F*G23*G31*A6F*A2F*A3F //P11*T11*L13*HRA*CSF	PDS34
LOSP	1765	1.0555E-06	/OGF*Y5F*Z6F*W2F*X3F*FO3/SBF*CCF/P11*STF *T12*L13*P21*T22*VF5*LR6*CSF	PDS15

TABLE 3.4-7: IP-2 Functional Accident Sequence Grouping According to NUMARC Guidelines

Functional Accident Sequence	Definition	Core Damage Frequency
IA	Accident Sequences Involving Loss of Both Primary and Secondary Heat Removal in the Injection Phase.	1.42E-05
IB	Accident Sequences Involving Loss of Both Primary and Secondary Heat Removal in the Recirculation Phase.	5.58E-07
IIA	Accident Sequences Involving an Induced LOCA with Loss of Primary Coolant Make Up or Adequate Heat Removal in the Injection Phase.	1.55E-06
IIB	Accident Sequences Involving an Induced LOCA with Loss of Primary Coolant Make Up or Adequate Heat Removal in the Recirculation Phase.	8.50E-08
IIIA	Accident Sequences Initiated by a Small LOCA with Loss of Primary Coolant Make Up or Adequate Heat Removal in the Injection Phase.	2.26E-06
IIIB	Accident Sequences Initiated by a Small LOCA with Loss of Primary Coolant Make Up or Adequate Heat Removal in the Recirculation Phase.	3.32E-06
IIIC	Accident Sequences Initiated by a Medium or Large LOCA with Loss of Primary Coolant Make Up in the Injection Phase.	1.39E-06

TABLE 3.4-7(cont): **IP-2 Functional Accident Sequence Grouping According to NUMARC Guidelines**

Functional Accident Sequence	Definition		Core Damage Frequency
IIID	Accident Sequences Initiated by a Medium or Large LOCA with Loss of Primary Coolant Make Up in the Recirculation Phase.		3.45E-06
IV	Accident Sequences Involving Failure of Reactivity Control.		1.81E-06
VA	Systems LOCA Outside Containment with Loss of Effective Coolant Inventory Make up		2.67E-08
VB	Steam Generator Tube Rupture with Loss of Effective Coolant Inventory Make UP and a stuck open valve on the Ruptured SG.		3.72E-07
VC	Steam Generator Tube Rupture with Loss of Effective Coolant Inventory Make up and a cycling SG Relief Valve which closes when RCS depressurizes at vessel failure.		1.25E-06
		Total	3.02E-05

Notes:

1) Based on grouping of all sequences > 5.0E-09/yr ie 96.5% of total CDF.

2) Induced LOCAs include, RCP seal LOCA due to loss of seal cooling, induced tube rupture following main steam line break, or non-isolated stuck open PORV.

3) Following loss of offsite power, staion blackout, no AC power recovery in 1 hour and loss of auxiliary feed water, an induced seal LOCA or stuck open PORV may occur. However, since core damge will occur directly as a result of lack of heat removal (regardless of the induced LOCA) such sequences have been categorized as IA.

TABLE 3.4-8: Summary of Core Damage Frequency by Initiator (> 1.E-09 contribution per year)

Symbol	Initiating Event	Contribution to cdf (/yr)	%
		LOCAs[1]	
BECCSL	LOCA Beyond ECCS	3.000E-07	0.96
LLOCA	Large LOCA	2.560E-06	8.20
MLOCA	Medium LOCA	1.902E-06	6.09
SLOCA	Small LOCA	5.659E-06	18.13
		SGTR w/ SOV+SGTR w/o SOV	
SGTR	S.G. Tube Rupture	1.623E-06	5.20
		General Transients	
TTRIP	Turbine Trip	2.678E-06	8.58
RXTRIP	Reactor Trip	4.380E-06	14.03
LOFW	Loss of Feedwater	2.715E-06	8.70
CPI	Core Power Increase	3.824E-08	0.12
LOPF	Loss of Prim. Flow	1.158E-07	0.37
MSIVC	MSIV Closure	2.418E-07	0.77
MSLBOC	Stm. Line Brk O.C	1.004E-08	0.03
		Station Blackout + General Transient	
LOSP	Loss of Offsite Power	5.926E-06	18.98
		Loss of Support Systems Initiating Event	
LODC21	Loss of 125v dc Bus D21	5.052E-07	1.62
LODC22	Loss of 125v dc Bus D22	3.781E-07	1.22
LOSW	Loss of Non-Essential Service Water	1.079E-08	0.03
LOCCW	Loss of Component Cooling Water	3.586E-07	1.15
LO692	Loss of 6.9 kv Bus 2	2.014E-08	0.06
LO693	Loss of 6.9 Kv Bus 3	2.261E-08	0.07
		Interfacing Systems LOCA	
VSEQ	Interfacing Systems LOCA (Event V)	2.672E-08	0.09

TABLE 3.4-8 (cont): Summary of Core Damage Frequency by Initiator (> 1.E-09 contribution per year)

Symbol	Initiating Event	Contribution to cdf (/yr)	%
		ATWS	
TTRIPA	Turbine Trip ATWS	4.883E-07	1.56
LOFWA	Loss of Feedwater ATWS	4.978E-07	1.59
MSIVCA	MSIV Closure ATWS	4.396E-08	0.14
LOSPA	Loss of Offsite Power ATWS	5.673E-07	1.82
LOCCWA	Loss of Component Cooling Water ATWS	1.540E-07	0.49
	Total CDF	3.13E-05	100.00

TABLE 3.4-9: Summary of Core Damage Frequency by Initiator Group

Initiating Event Group	Contribution to CDF (/ yr.)	%
LOCAs	1.043E-05	33.30
Steam Generator Tube Rupture with SOV	3.725E-07	1.19
Steam Generator Tube Rupture without SOV	1.250E-06	3.99
General Transients	1.167E-05	37.26
Station Blackout	4.467E-06	14.26
Interfacing Systems LOCA	2.672E-08	0.09
Loss of Support System Initiating Events	1.296E-06	4.14
Anticipated Transients Without Scram	1.810E-06	5.78
Total CDF	3.13E-05	100.00

TABLE 3.4-10: Top Event Importance Sorted By Non Guaranteed Failure Importance

Symbol	Top Event Description	Non Guaranteed Failure Importance
L1	Auxiliary Feedwater	0.48
O1	Primary Bleed	0.32
T1	Start Gas Turbine in 1/2 hr	0.19
P1	Recover Offsite Power in 1/2 hr.	0.19
LR	Low Pressure Recirculation	0.18
G2	EDG No 22	0.12
P2	Offsite Power Recovery in 1 hour (given P1)	0.11
T2	Gas Turbine Start and Run in 1 hr (given T1)	0.10
G1	EDG No 21	0.10

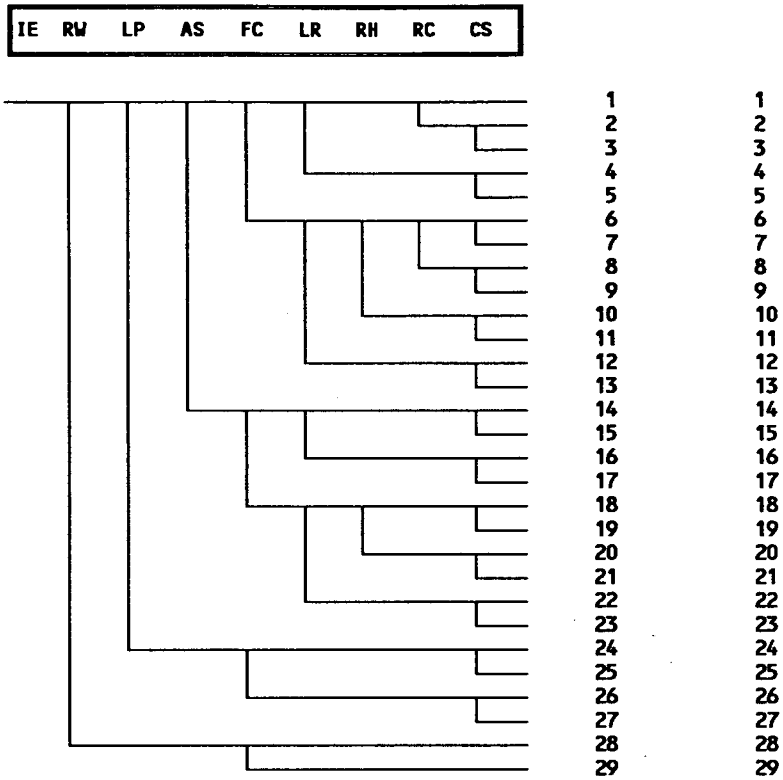
TABLE 3.4-11: Comparisons of Initiating Events and in the IP-2 IPE and Shutdown Decay Heat Removal Case Study

IP-2 IPE	Case Study	
Small LOCA	Small LOCA	
Loss of Offsite Power	Loss of Offsite Power	
Transients resulting from loss of Feedwater	Transients resulting from loss of PCS	
Transient due to MSIV Closure		
Transients due to turbine trip, loss of Primary Flow, Power Increase.	Transients with offsite and PCS available	Core
Transient resulting from loss of a DC bus (D21 or D22 treated separately)	Transient resulting from loss of AC or DC Bus	
Transient resulting from loss of a 6.9 kv bus (bus 2 and 3 treated separately)		
Medium LOCA		
Large LOCA		
Interfacing LOCA		
LOCA Beyond ECCS Capacity		
Steam Generator Tube Rupture		
Loss of Component Cooling		
Loss of Seervice Water		
Steam LIne Break Inside Containemnt		
Steam LIne Break Outside Containment		
Anticipated Transients without Scram		

TABLE 3.4-12: Comparison of Front Line and Support Systems in the IP-2 IPE and Shutdown Decay Heat Removal Case Study.

IP-2 IPE	Case Study
Front Line Systems	
Auxiliary Feedwater	Auxiliary Feedwater
High Pressure Injection and Recirculation System	High Pressure Injection and Recirculation System
Low Pressure Injection and Recirculation System	Low Pressure Injection and Recirculation System
Pressurizer Safety and Relief Valves	Pressurizer Safety and Relie Valves
Secondary Safety and Relief Valves	Secondary Safety and Relief Valves
Containment Spray Recircualtion and Heat Removal	
Containemnt Fan Coolers	
Charging Pumps	
Emergency Boration	
Support Systems	
Emergency AC and DC power	Emergency AC and DC power
Service Water	Service Water
Component Cooling	Component Cooling
Emergency Safeguards Actuation	Emergency Safeguards Actuation
Reactor Protection System	
Emergency Diesel Generator Building Ventilation	

Figure 3.1-1: Large LOCA Event Tree (ET-1)

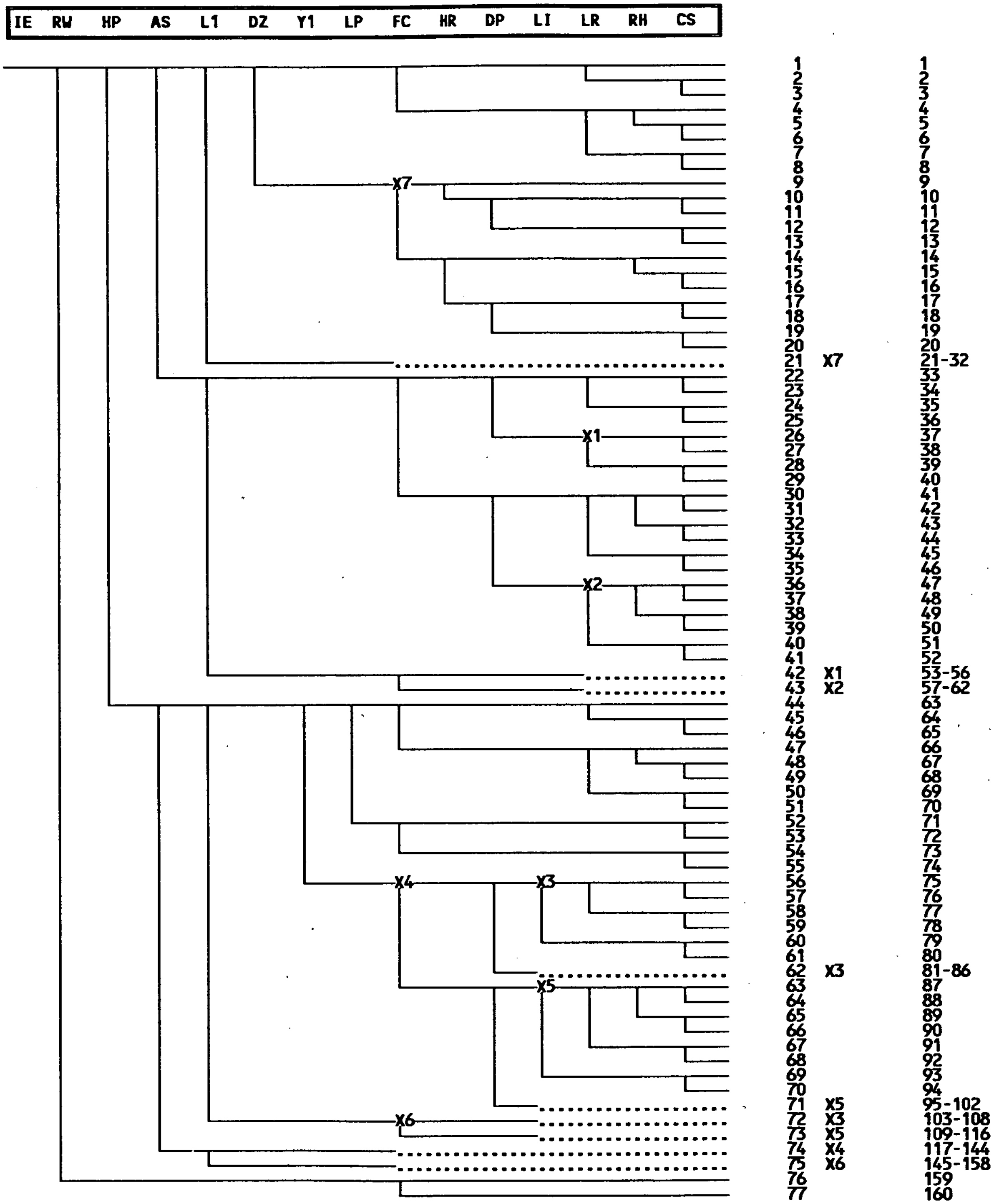


Top Event Designator

IE	INITIATING EVENT, LARGE LOCA
RW	REFUELING WATER STORAGE TANK
LP	LOW PRESSURE INJECTION
AS	ACCUMULATOR INJECTION
FC	FAN COOLER UNITS
LR	LOW HEAD RECIRCULATIONS
RH	RECIRCULATION HEAT REMOVAL
RC	HOT LEG RECIRCULATION
CS	CONTAINMENT SPRAY INJECTION AND RECIRCULATION

FIGURES FOR SECTION 3

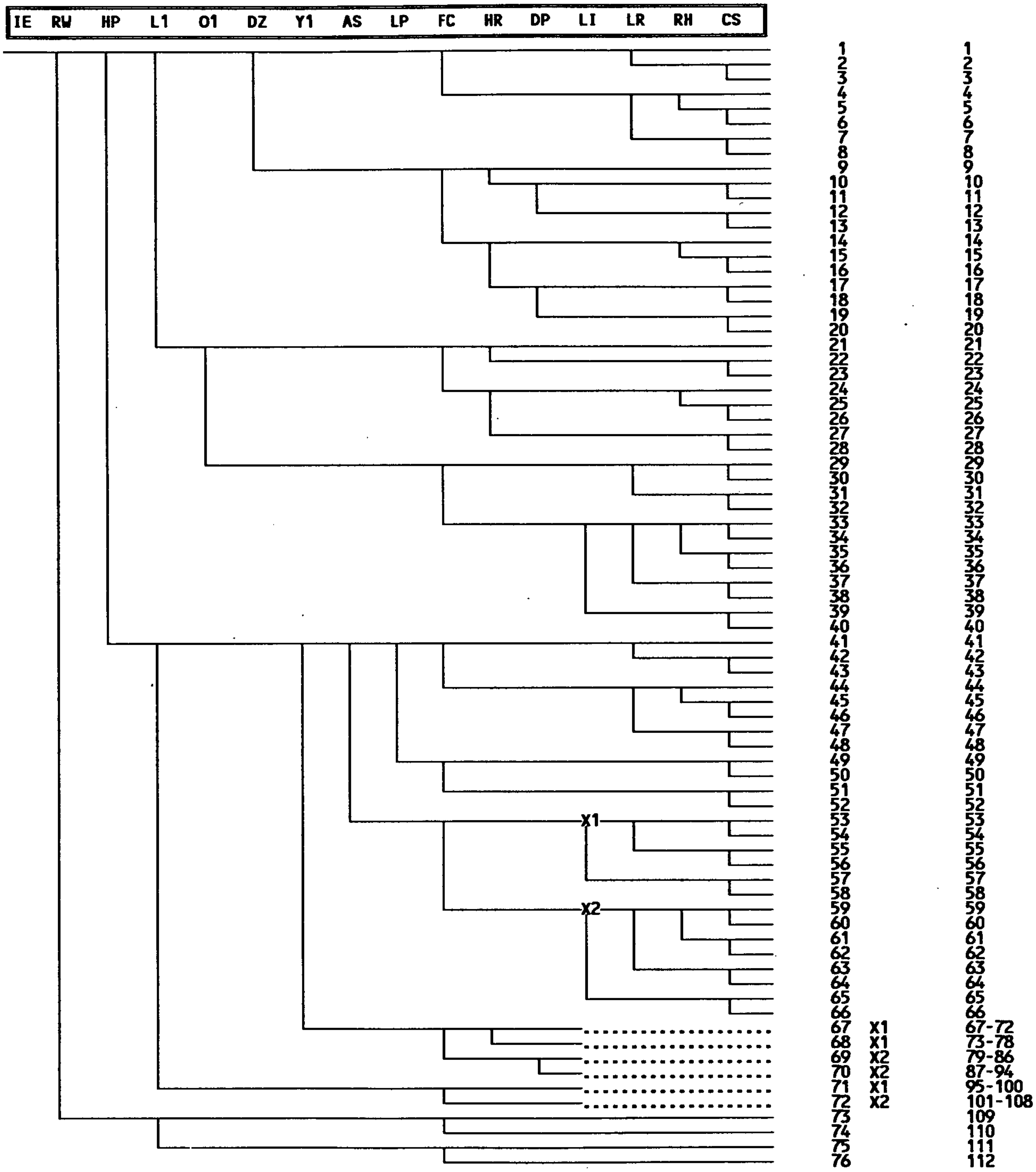
Figure 3.1-2: Medium LOCA Event Tree (ET-2)



Top Event Designators

IE	INITIATING EVENT (MEDIUM LOCA)	RW	RWST
HP	HIGH PRESSURE INJECTION	AS	ACCUMULATOR INJECTION
L1	AFWS ACTUATION AND SECONDARY COOLING	DZ	POST LOCA COOLDOWN AND DEPRESSURIZATION
Y1	CORE COOLING RECOVERY	LP	LOW PRESSURE INJECTION
FC	FAN COOLER UNITS	HR	HIGH HEAD RECIRCULATION
DP	DEPRESSURIZATION BEFORE VESSEL FAILURE	LI	LOW HEAD INJECTION - LATE
LR	LOW PRESSURE RECIRCULATION	RH	RECIRCULATION COOLING
CS	CS INJECTION AND CS RECIRCULATION		

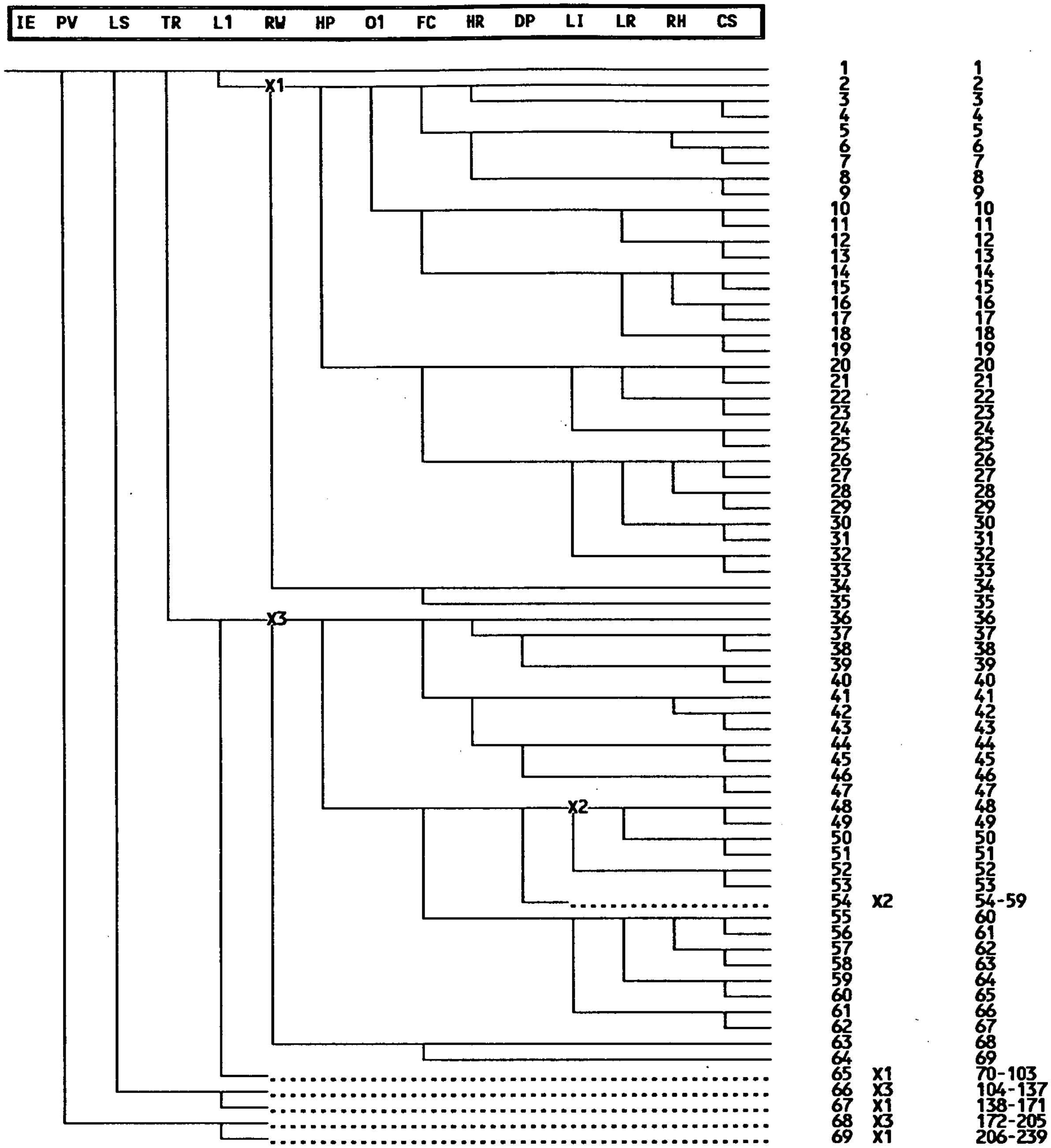
Figure 3.1-3: Small LOCA Event Tree (ET-3)



Top Event Designator

IE	INITIATING EVENT SMALL LOCA (ET-3)	RW	RWST AND OUTLET VALVE
HP	HIGH HEAD INJECTION (HH-2)	L1	AFWS ACTUATION AND SECONDARY COOLING (L-1)
O1	PRIMARY COOLING FEED AND BLEED (OP-1)	DZ	POST LOCA COOLDOWN AND PRESSURIZATION
Y1	CORE COOLING RECOVERY	AS	ACCUMULATOR INJECTION
LP	LOW PRESSURE INJECTION	FC	CONTAINMENT FAN COOLERS (CF-1)
HR	RECIRCULATION COOLING (R-2)	DP	DEPRESSURIZATION BEFORE VESSEL FAILURE
LI	LATE INJECTION	LR	LOW HEAD RECIRCULATION
RH	RECIRCULATION COOLING	CS	CS INJECTION AND CS RECIRCULATION

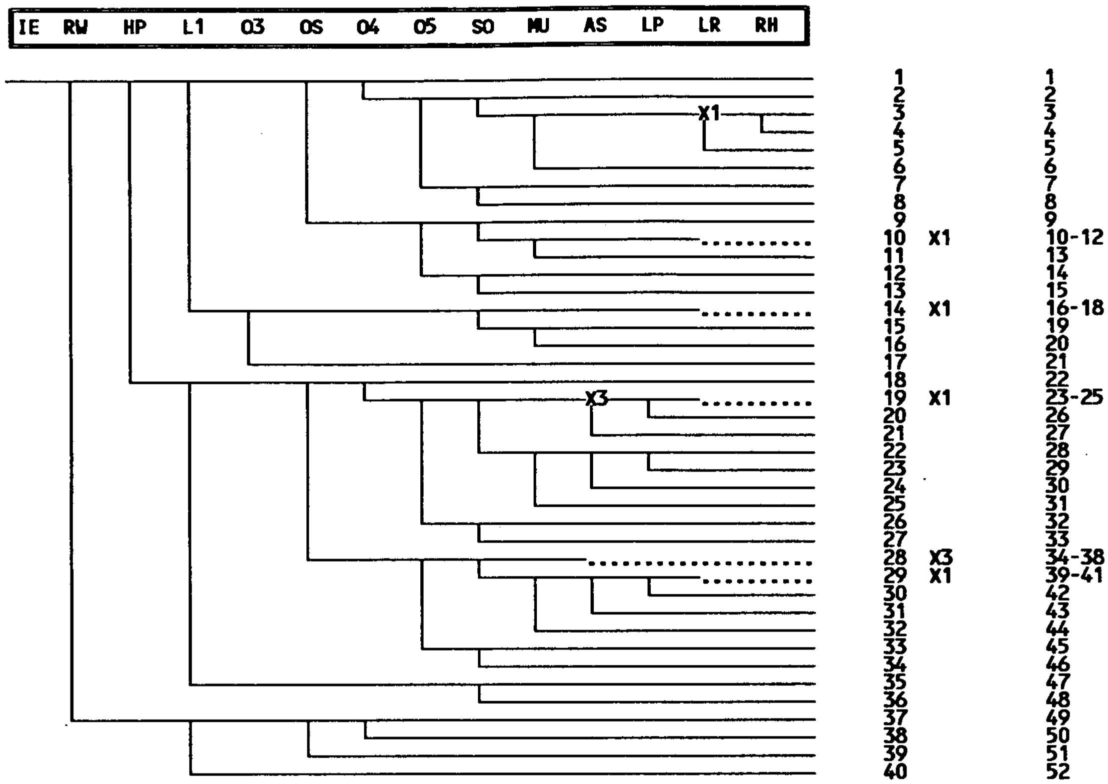
Figure 3.1-4: General Transient Event Tree



Top Event Designator

IE	INITATING EVENT - GENERAL TRANSIENT	PV	PORVS RECLOSE
LS	RCS SEAL COOLING	TR	CONSEQUENTIAL STEAM GENERATOR TUBE RUPTURE
L1	AFWS ACTUATION AND SECONDARY COOLING	RW	RWST
HP	HIGH PRESSURE SAFETY INJECTION	01	PRIMARY COOLING - BLEED ONLY
FC	FAN COOLER UNITS	HR	HIGH HEAD RECIRCULATION
DP	DEPRESSURIZE BEFORE VESSEL FAILURE	LI	LOW HEAD INJECTION - LATE
LR	LOW PRESSURE INJECTION - LATE	RH	RECIRCULATION COOLING
CS	CS SPRAY AND CS RECIRCULATION		

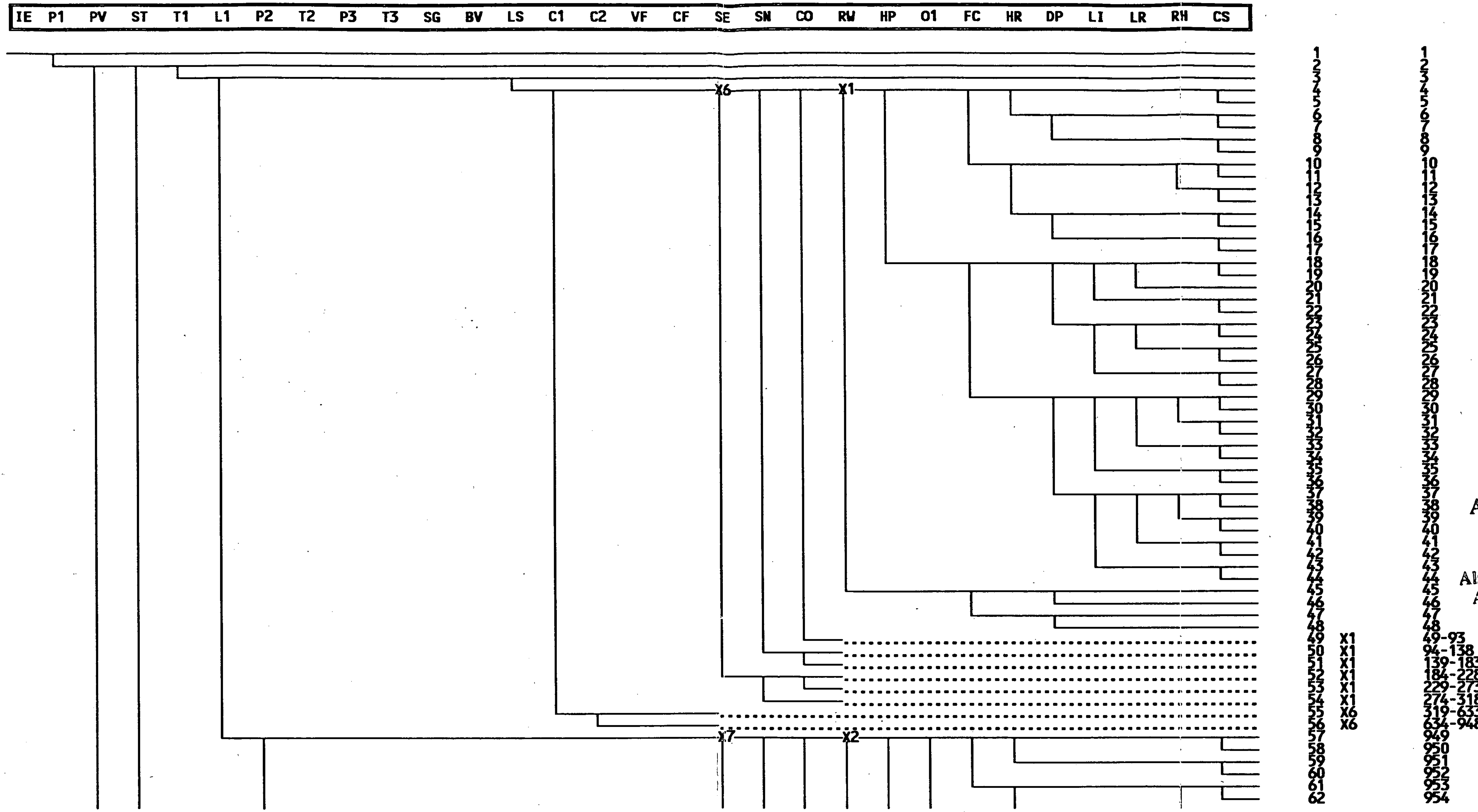
Figure 3.1-5: Steam Generator Tube Rupture Event Tree (ET 4)



Top Event Designator

IE INITIATING EVENT - STEAM GENERATOR TUBE RUPTURE
RW RWST
HP HIGH HEAD INJECTION
L1 AFWS ACTUATION & SECONDARY COOLING
O3 OPERATOR COOLDOWN AND DEPRESSURIZE WITHOUT AFS
OS ISOLATE FAULTED STEAM GENERATOR EARLY
O4 OPERATOR COOLS DOWN AND DEPRESSURIZES EARLY
O5 OPERATOR COOLS DOWN AND DEPRESSURIZES LATE
SO ISOLATE FAULTED SG LATE
MU RWST MAKEUP
AS ACCUMULATORS
LP LOW PRESSURE INJECTION
LR LOW HEAD RECIRCULATION
RH RECIRCULATION HEAT REMOVAL

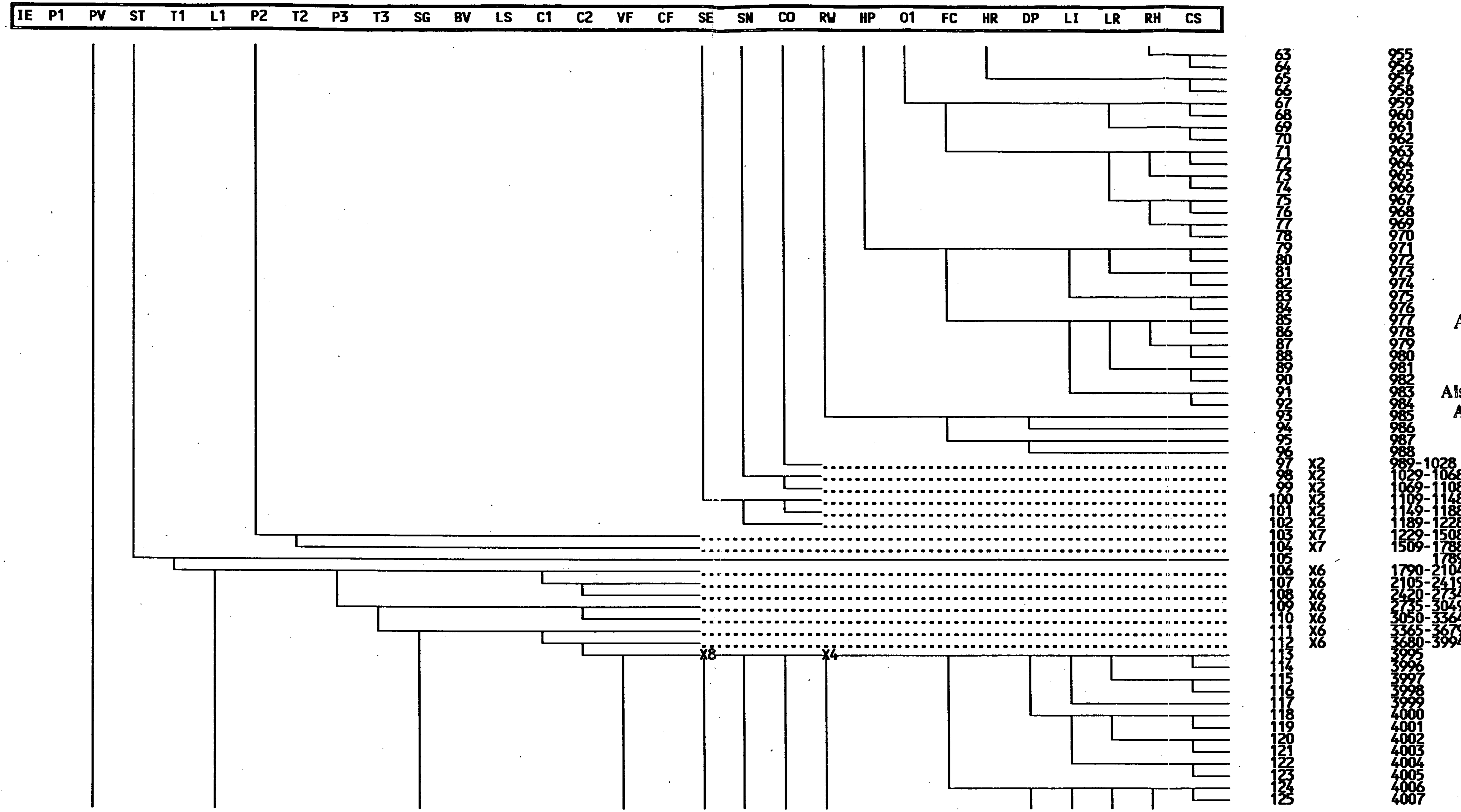
Figure 3.1-6: Loss of Offsite Power Event Tree (Page 1 of 4)



Top Event Designator............................

IE	LOSS OF OFFSITE POWER INITIATING EVENT	P1	OSP POWER REC BETWEEN 0<=T<=1/2 HRS.	PV	PORV'S
ST	STATION BLACKOUT/EDG BUILDING VENTILATION	T1	GT'S START AND LOAD BETWEEN 0 <= T <= 1/2 HRS.	L1	AUXILIARY FEEDWATER SYSTEM
P2	OSP RECOVERY BETWEEN 1/2 <= T <= 1 HR.	T2	GT'S START AND LOAD BETWEEN 1/2<= T<= 1 HR.	P3	OSP RECOVERY BETWEEN 1 <= T <= 3 HRS.
T3	GT'S START ANS LOAD BETWEEN 1/2<= T< 3 HRS.	SG	OPERATORS CONTROL S/G LEVEL GIVEN LOSS OF ALL AC AND DEPLETION OF DC POWER	BV	BLOCK VALVES
LS	RCP SEAL COOLING	C1	NO OSP RECOVERY BEFORE CORE UNCOVERY	C2	GT'S FAIL TO START BEFORE CORE UNCOVERY
VF	NO OSP RECOVERY BETWEEN CORE UNCOVERY AND CORE SLUMP	CF	NO OSP RECOVERY BETWEEN CORE SLUMP AND CONTAINMENT FAILURE	SE	ESSENTIAL SERVICE WATER RECOVERY
SN	NON-ESSENTIAL SERVICE WATER RECOVERY	CO	COMPONENT COOLING WATER RECOVERY	RW	RWST
HP	HIGH PRESSURE INJECTION	O1	PRIMARY COOLING - BLEED ONLY	FC	FAN COOLER UNITS
HR	HIGH PRESSURE RECIRCULATION	DP	DEPRESSURIZATION	LI	LOW PRESSURE INJECTION LATE
LR	LOW PRESSURE RECIRCULATION	RH	RECIRCULATION COOLING	CS	CONTAINMENT SPRAY

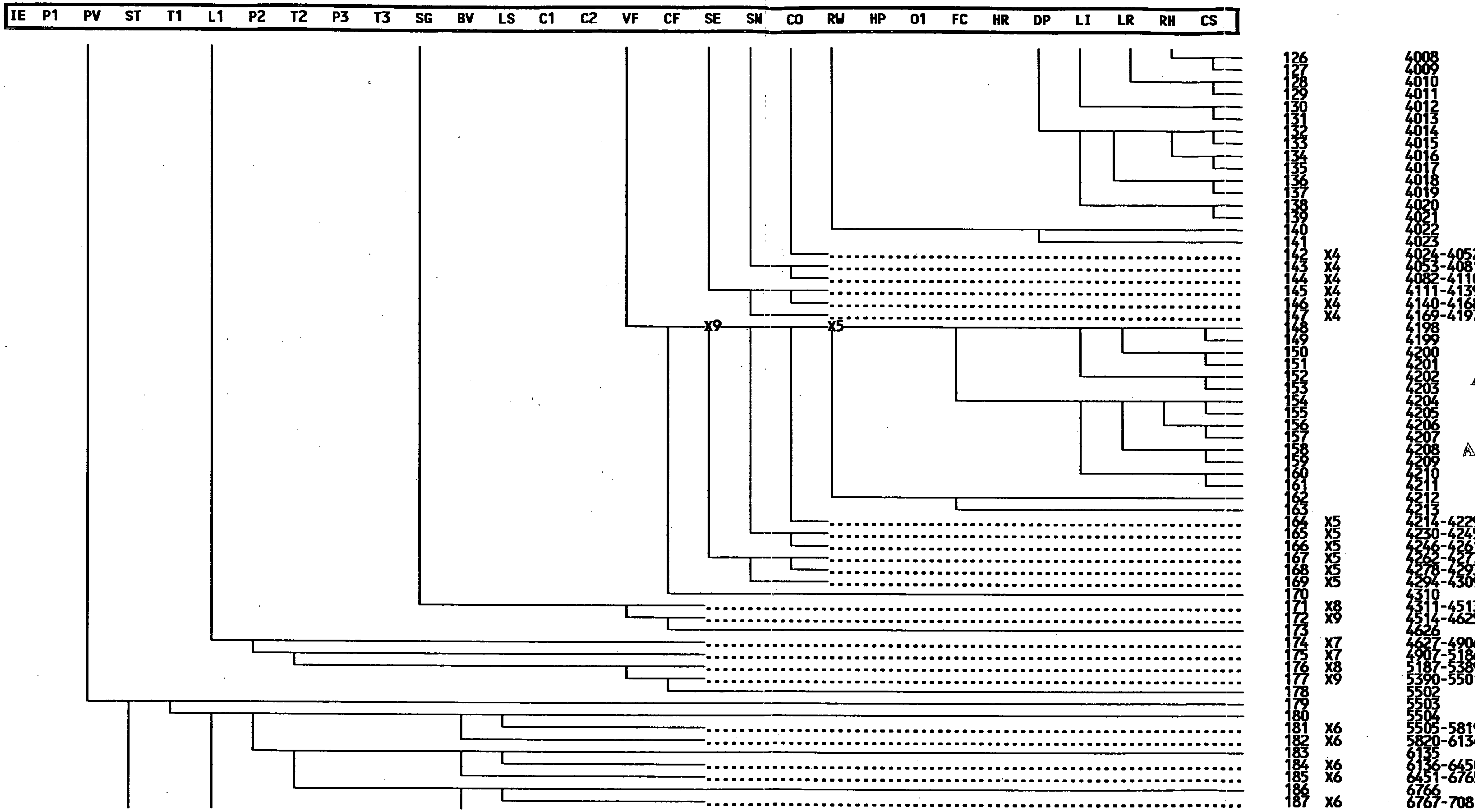
Figure 3.1-6: Loss of Offsite Power Event Tree (Page 2 of 4)



Top Event Designator............................

IE	LOSS OF OFFSITE POWER INITIATING EVENT	P1	OSP POWER REC BETWEEN 0<=T<=1/2 HRS.	PV	PORV'S
ST	STATION BLACKOUT/EDG BUILDING VENTILATION	T1	GT'S START AND LOAD BETWEEN 0 <= T <= 1/2 HRS.	L1	AUXILIARY FEEDWATER SYSTEM
P2	OSP RECOVERY BETWEEN 1/2 <= T <= 1 HR.	T2	GT'S START AND LOAD BETWEEN 1/2<= T<= 1 HR.	P3	OSP RECOVERY BETWEEN 1 <= T <= 3 HRS.
T3	GT'S START ANS LOAD BETWEEN 1/2<= T< 3 HRS.	SG	OPERATORS CONTROL S/G LEVEL GIVEN LOSS OF ALL AC AND DEPLETION OF DC POWER	BV	BLOCK VALVES
LS	RCP SEAL COOLING	C1	NO OSP RECOVERY BEFORE CORE UNCOVERY	C2	GT'S FAIL TO START BEFORE CORE UNCOVERY
VF	NO OSP RECOVERY BETWEEN CORE UNCOVERY AND CORE SLUMP	CF	NO OSP RECOVERY BETWEEN CORE SLUMP AND CONTAINMENT FAILURE	SE	ESSENTIAL SERVICE WATER RECOVERY
SN	NON-ESSENTIAL SERVICE WATER RECOVERY	CO	COMPONENT COOLING WATER RECOVERY	RW	RWST
HP	HIGH PRESSURE INJECTION	O1	PRIMARY COOLING - BLEED ONLY	FC	FAN COOLER UNITS
HR	HIGH PRESSURE RECIRCULATION	DP	DEPRESSURIZATION	LI	LOW PRESSURE INJECTION LATE
LR	LOW PRESSURE RECIRCULATION	RH	RECIRCULATION COOLING	CS	CONTAINMENT SPRAY

Figure 3.1-6: Loss of Offsite Power Event Tree (Page 3 of 4)



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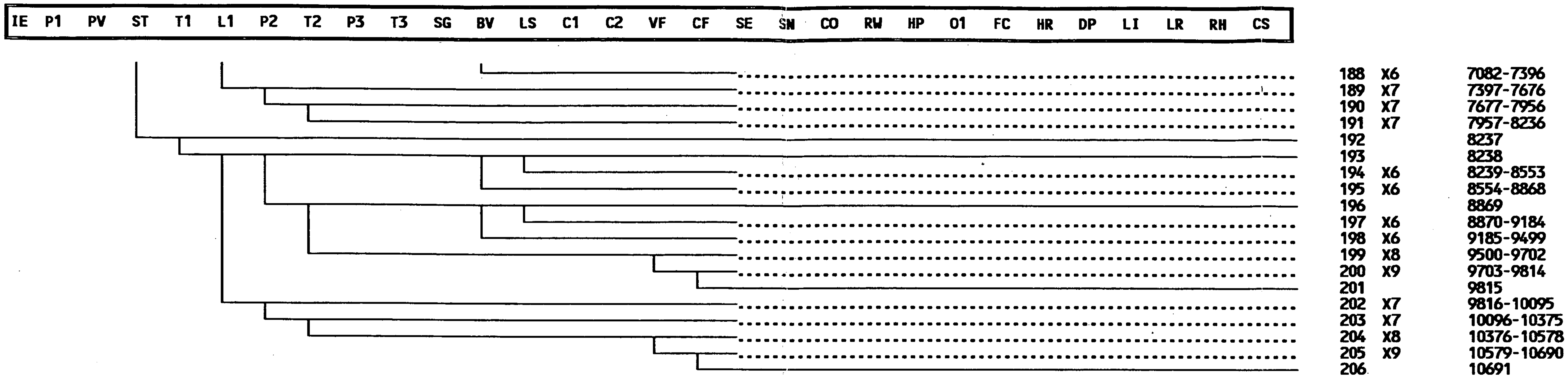
Top Event Designator............................

IE	LOSS OF OFFSITE POWER INITIATING EVENT	P1	OSP POWER REC BETWEEN 0<=T<=1/2 HRS.	PV	PORV'S
ST	STATION BLACKOUT/EDG BUILDING VENTILATION	T1	GT'S START AND LOAD BETWEEN 0 <= T <= 1/2 HRS.	L1	AUXILIARY FEEDWATER SYSTEM
P2	OSP RECOVERY BETWEEN 1/2 <= T <= 1 HR.	T2	GT'S START AND LOAD BETWEEN 1/2<= T<= 1 HR.	P3	OSP RECOVERY BETWEEN 1 <= T <= 3 HRS.
T3	GT'S START ANS LOAD BETWEEN 1/2<= T< 3 HRS.	SG	OPERATORS CONTROL S/G LEVEL GIVEN LOSS OF ALL AC AND DEPLETION OF DC POWER	BV	BLOCK VALVES
LS	RCP SEAL COOLING	C1	NO OSP RECOVERY BEFORE CORE UNCOVERY	C2	GT'S FAIL TO START BEFORE CORE UNCOVERY
VF	NO OSP RECOVERY BETWEEN CORE UNCOVERY AND CORE SLUMP	CF	NO OSP RECOVERY BETWEEN CORE SLUMP AND CONTAINMENT FAILURE	SE	ESSENTIAL SERVICE WATER RECOVERY
SN	NON-ESSENTIAL SERVICE WATER RECOVERY	CO	COMPONENT COOLING WATER RECOVERY	RW	RWST
HP	HIGH PRESSURE INJECTION	O1	PRIMARY COOLING - BLEED ONLY	FC	FAN COOLER UNITS
HR	HIGH PRESSURE RECIRCULATION	DP	DEPRESSURIZATION	LI	LOW PRESSURE INJECTION LATE
LR	LOW PRESSURE RECIRCULATION	RH	RECIRCULATION COOLING	CS	CONTAINMENT SPRAY

9208200239-03

Figure 3.1-6: Loss of Offsite Power Event Tree (Page 4 of 4)



Top Event Designator............................

IE	LOSS OF OFFSITE POWER INITIATING EVENT	P1	OSP POWER REC BETWEEN 0<=T<=1/2 HRS.	PV	PORV'S
ST	STATION BLACKOUT/EDG BUILDING VENTILATION	T1	GT'S START AND LOAD BETWEEN 0 <= T <= 1/2 HRS.	L1	AUXILIARY FEEDWATER SYSTEM
P2	OSP RECOVERY BETWEEN 1/2 <= T <= 1 HR.	T2	GT'S START AND LOAD BETWEEN 1/2<= T<= 1 HR.	P3	OSP RECOVERY BETWEEN 1 <= T <= 3 HRS.
T3	GT'S START ANS LOAD BETWEEN 1/2<= T< 3 HRS.	SG	OPERATORS CONTROL S/G LEVEL GIVEN LOSS OF ALL AC AND DEPLETION OF DC POWER	BV	BLOCK VALVES
LS	RCP SEAL COOLING	C1	NO OSP RECOVERY BEFORE CORE UNCOVERY	C2	GT'S FAIL TO START BEFORE CORE UNCOVERY
VF	NO OSP RECOVERY BETWEEN CORE UNCOVERY AND CORE SLUMP	CF	NO OSP RECOVERY BETWEEN CORE SLUMP AND CONTAINMENT FAILURE	SE	ESSENTIAL SERVICE WATER RECOVERY
SN	NON-ESSENTIAL SERVICE WATER RECOVERY	CO	COMPONENT COOLING WATER RECOVERY	RW	RWST
HP	HIGH PRESSURE INJECTION	01	PRIMARY COOLING - BLEED ONLY	FC	FAN COOLER UNITS
HR	HIGH PRESSURE RECIRCULATION	DP	DEPRESSURIZATION	LI	LOW PRESSURE INJECTION LATE
LR	LOW PRESSURE RECIRCULATION	RH	RECIRCULATION COOLING	CS	CONTAINMENT SPRAY

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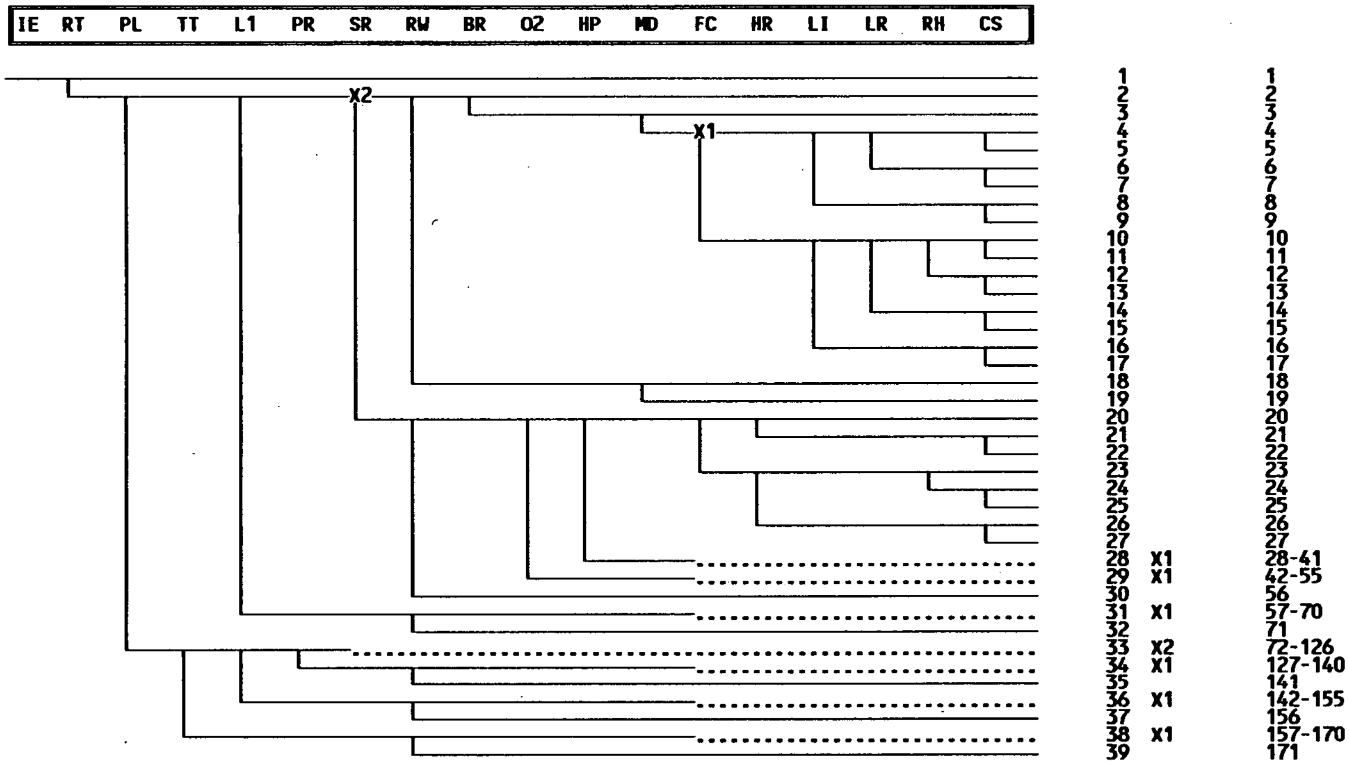
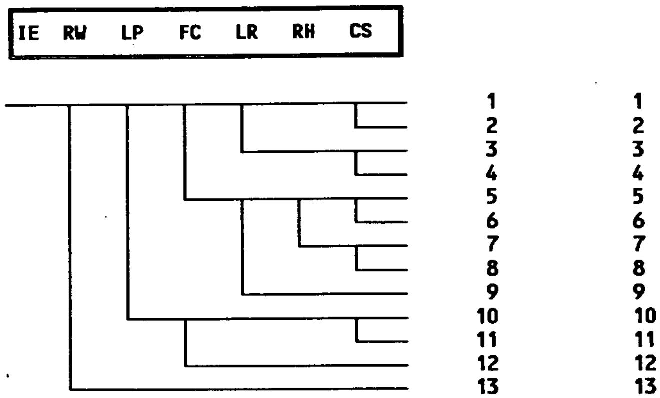
Figure 3.1-7: ATWS Event Tree



Top Event Designators

IE	INITIATING EVENT - Transients/ LOCAs	RT	REACTOR TRIP
PL	POWER LEVEL > 40%	TT	TURBINE TRIP
L1	AUX FEEDWATER	PR	PRESUURE RELIEF
SR	SECURE FORM PRESSURE RELIEF	RW	RWST
BR	EMERGENCY BORATION	O2	RCS BLEED FOR SI BORATION
HP	HIGH PRESSURE INJECTION	MD	MANUALLY DEENERGIZE THE RODS
FC	FAN COOLER UNITS	HR	HIGH HEAD RECIRCULATION
LI	LOW HEAD INJECTION	LR	LOW HEAD RECIRCULATION
RH	RECIRCUALATION HEAT REMOVAL	CS	CONTAINMENT SPRAY

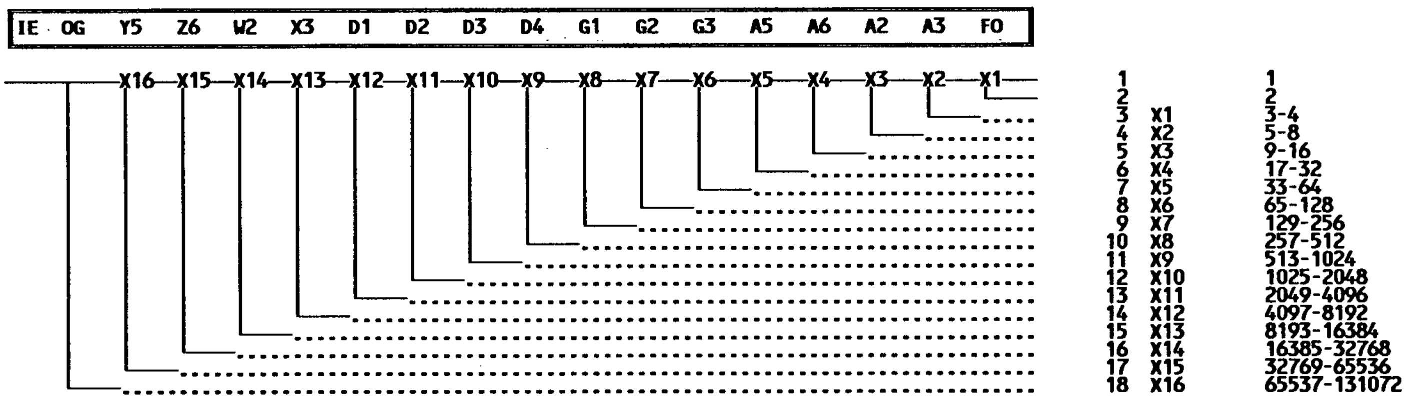
Figure 3.1-8: LOCA Beyond ECCS Capacity Event Tree



Top Event Designator

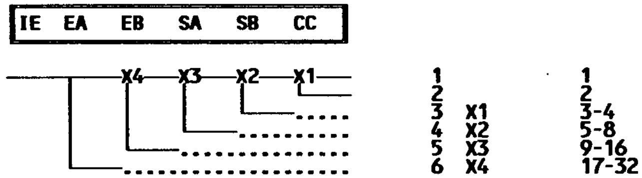
IE	INITIATING EVENT, LARGE LOCA	RW	REFUELING WATER STORAGE TANK
LP	LOW PRESSURE INJECTION	FC	FAN COOLER UNITS
LR	LOW HEAD RECIRCULATION	RH	RECIRCULATION HEAT REMOVAL
CS	CONTAINMENT SPRAY		

Figure 3.1-9: Electric Power Support Systems Event Tree



Top Event Designator	
IE	INITIATING EVENT
OG	OFFSITE GRID SYSTEM
Y5	6.9 KV BUS 5
Z6	6.9 KV BUS 6
W2	6.9 KV BUS 2
X3	6.9 KV BUS 3
D1	DC BUS 21
D2	DC BUS 22
D3	DC BUS 23
D4	DC BUS 24
G1	EDG 21
G2	EDG 22
G3	EDG 23
A5	480 V BUS 5A
A6	480 V BUS 6A
A2	480 V BUS 2A
A3	480 V BUS 3A
FO	EDG FUEL OIL SYSTEM

Figure 3.1-10: Other Support Systems Event Tree



Top Event Designator

IE	INITIATING EVENT FREQUENCY
EA	SAFETY INJECTION ACTUATION TRAIN A
EB	SAFETY INJECTION ACTUATION TRAIN B
SA	ESSENTIAL SERVICE WATER HEADER (2 HDR SYS)
SB	NON-ESSENTIAL SERVICE WATER HEADER (2 HDR SYS)
CC	COMPONENT COOLING SYSTEM

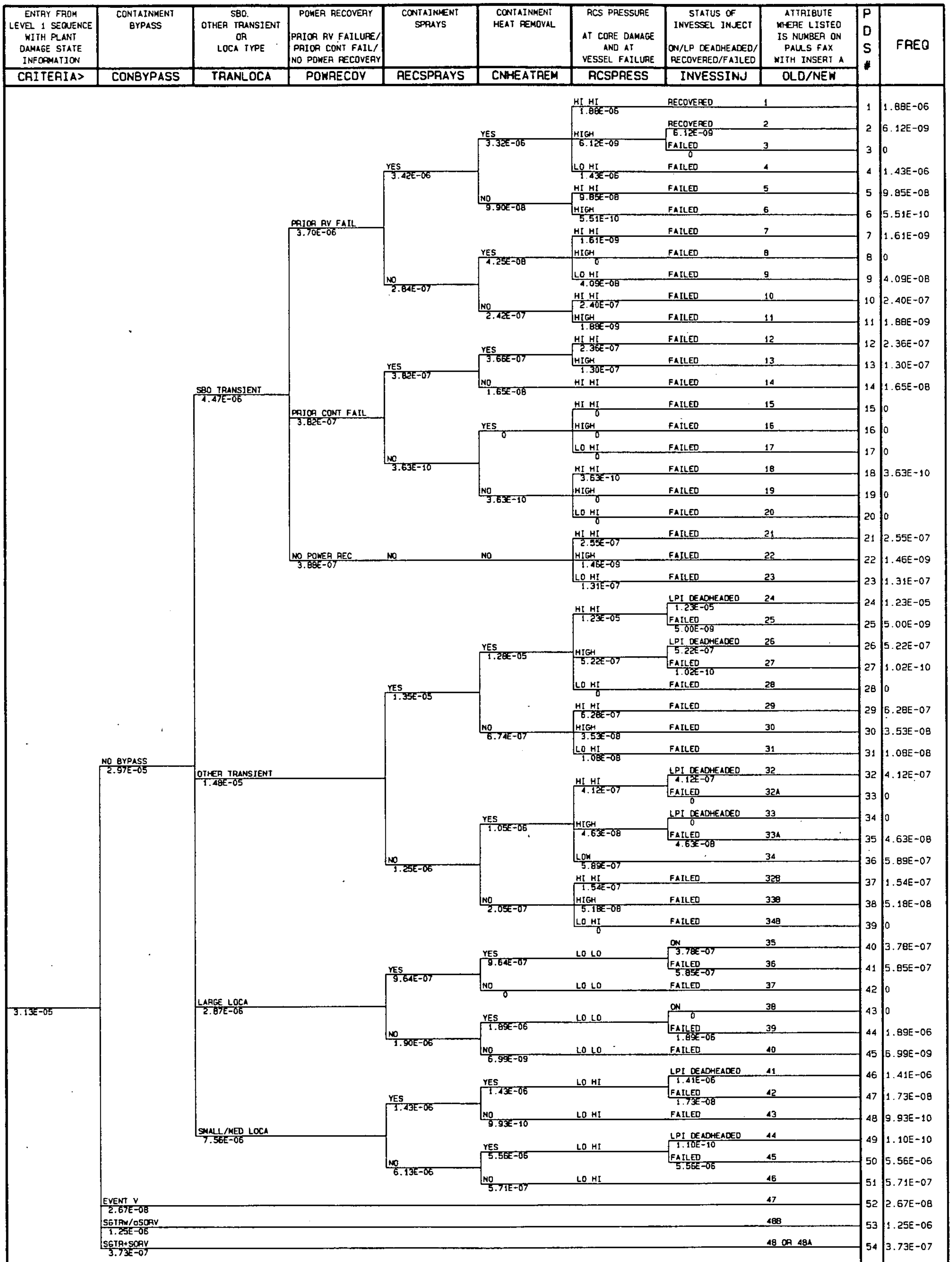


DIAGRAM: REV7-IP2.PDD 30 APR 92 DATA FILE: 30 APR 92 Sum = 3.132E-005

Figure 3.1-11

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

PLANT DAMAGE STATE GROUPING LOGIC

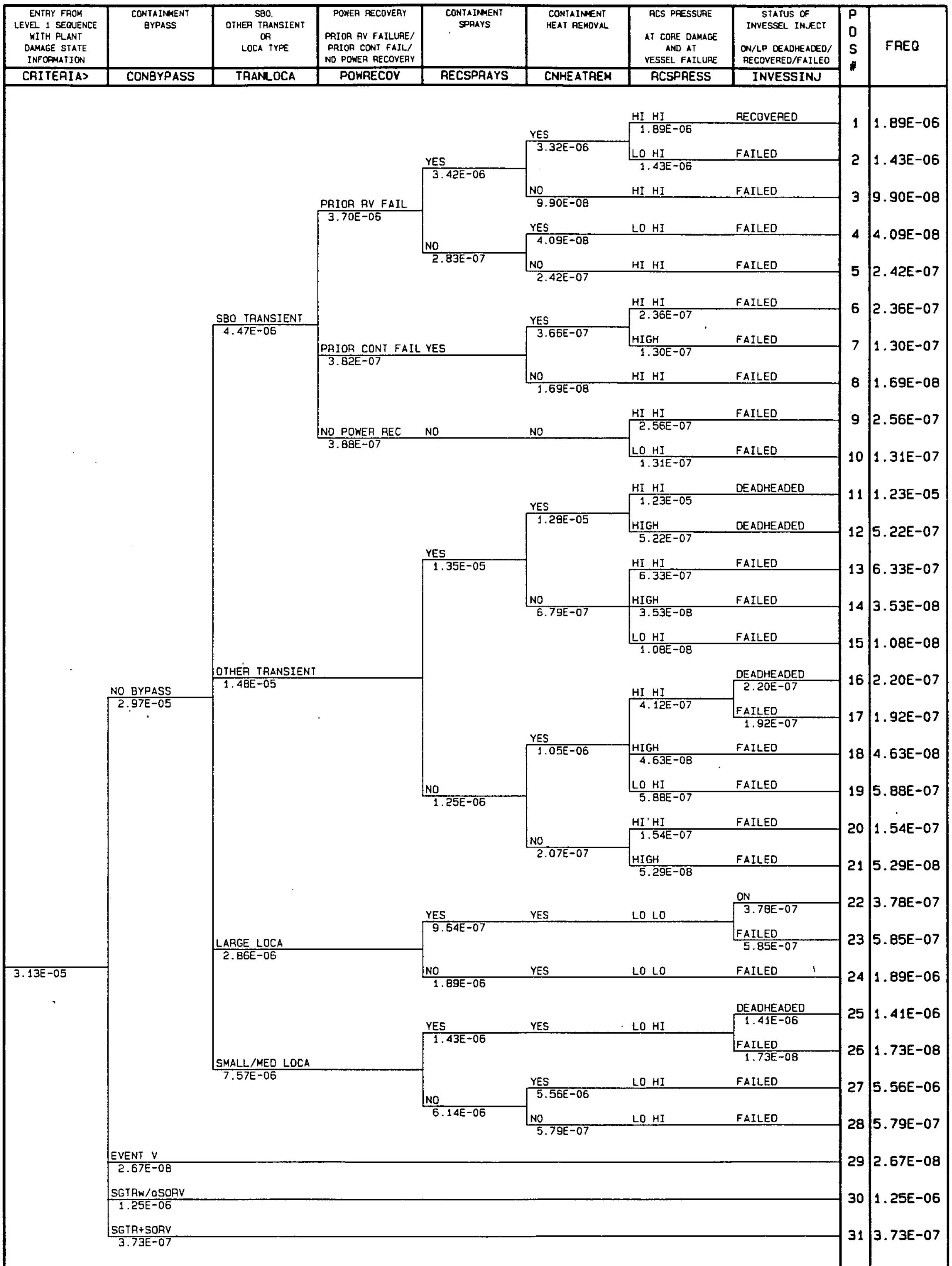
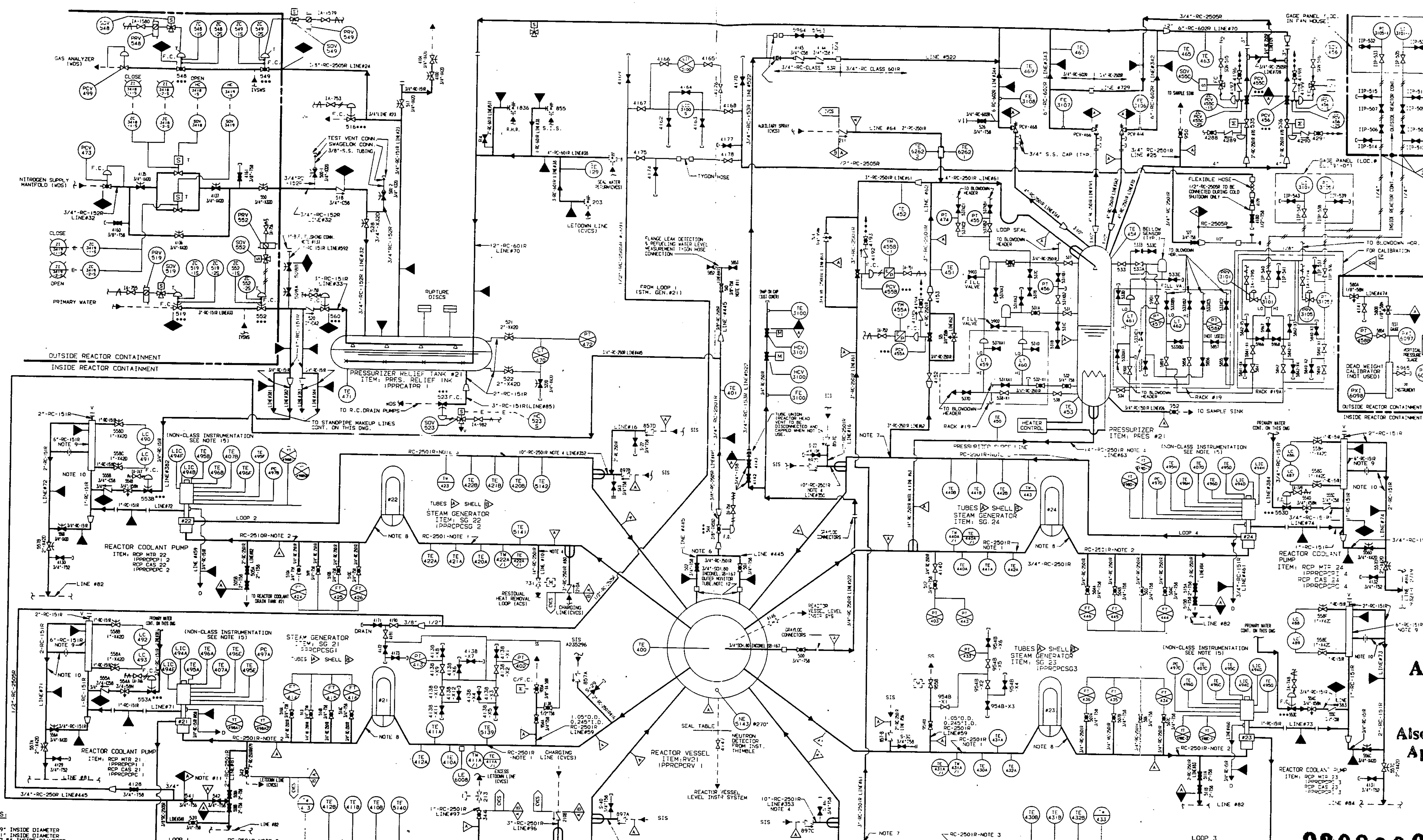


DIAGRAM: REV9-IP2.PDD 1 MAY 92 DATA FILE: 21 JUL 92 Sum = 3.132E-005

Figure 3.1-12

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

PLANT DAMAGE STATE GROUPING LOGIC



NOTES:

1. 29" INSIDE DIAMETER
2. 31" INSIDE DIAMETER
3. 27.5" INSIDE DIAMETER
4. SCHEDULE 140 PIPE
5. GLOBE VALVES NORMALLY INSTALLED WITH FLOW UNDER SEAT
6. LOCATE OUTSIDE SECONDARY SHIELD WALL VALVE NO.501 IS FROM INNER O-RING VALVE NO.502 IS FROM OUTER O-RING
7. SPRAY LINE SCOOP
8. ELBOW FLOW METERS
9. STAND PIPE IS SCH. 10S PIPE
10. PIPE SLOPED DOWNHILL TO DRAIN TANK
11. LOCATE VALVES 539, 540, 541 & 542 BELOW HOT LEG PIPING
12. TRANSITION WELD REQUIRED BETWEEN S.S. PIPING & INCONEL CONN. TO VESSEL
13. REFUELING CANAL FLUSH CONNECTION
14. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL
15. PER CLASSIFICATIONS 81-36.PE1.1 & 89-090-CL.THE FOLLOWING INSTRUMENTATION IS "NON-CLASS."

RCP-#21	RCP-#22	RCP-#23	RCP-#24
LIC-494A	LIC-494B	LIC-494C	LIC-494D
LIC-494E	LIC-494F	LIC-494G	LIC-494H
PC-497A	PC-497B	PC-497C	PC-497D
TE-407A	TE-407B	TE-407C	TE-407D
TE-495A	TE-495B	TE-495C	TE-495D
TE-495E	TE-495F	TE-495G	TE-495H
TE-496A	TE-496B	TE-496C	TE-496D
TE-496E	TE-496F	TE-496G	TE-496H
YT-498A-1	YT-498B-1	YT-498C-1	YT-498D-1
YT-498A-2	YT-498B-2	YT-498C-2	YT-498D-2

REFERENCES:

1. PROCESS FLOW DIAGRAM (W)
2. DEFINITION OF SYMBOLS
   (W) E SPEC. G675176 REV.2
3. INSTRUMENTATION AND CONTROL STANDARDS
   (W) SYMBOLS & APPLICATIONS FOR INSTRUMENT DIAGRAMS. SECTION 1.1. ISSUED AUG.12, 1966
   (W) INSTRUMENT INSTALLATION SECTION 3.0, ISSUED NOV.16, 1966
4. MATERIAL SPEC & FITTINGS
   (W) E. SPEC. G569866 REV.2
   (W) E. SPEC. G676398 REV.0

LEGEND

IVSWS - ISOLATION VALVE SEAL WATER SYS.
CVCS - CHEMICAL & VOLUME CONTROL SYS.
ACS - AUXILIARY COOLANT SYS.
SIS - SAFETY INJECTION SYS.
SS - SAMPLING SYS.
WDS - WASTE DISPOSAL SYS.

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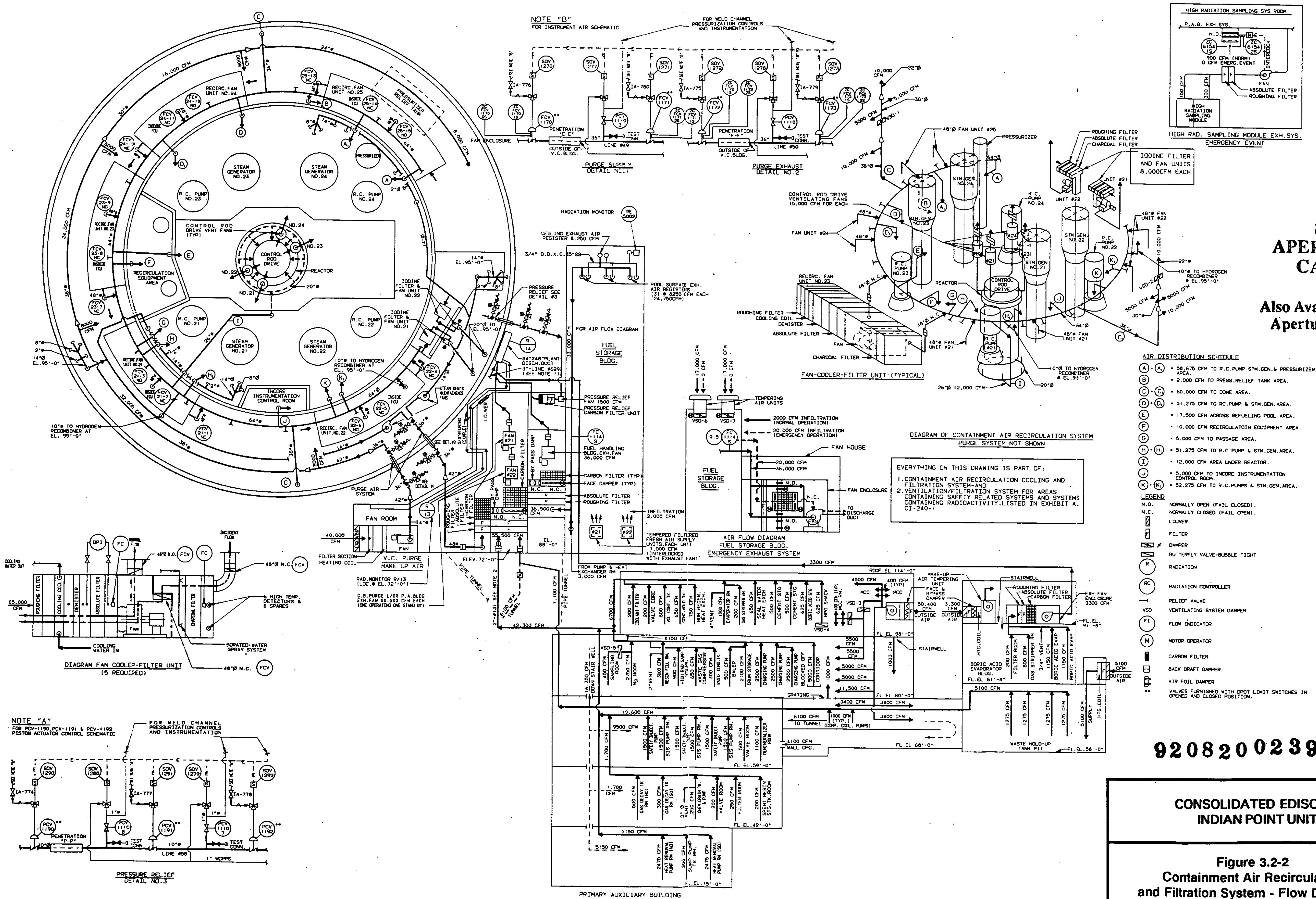
INDIAN POINT UNIT 2

Figure 3.2-1
Reactor Coolant System
Flow Diagram



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INDIAN POINT UNIT 2

Figure 3.2-2
Containment Air Recirculation and Filtration System - Flow Diagrams

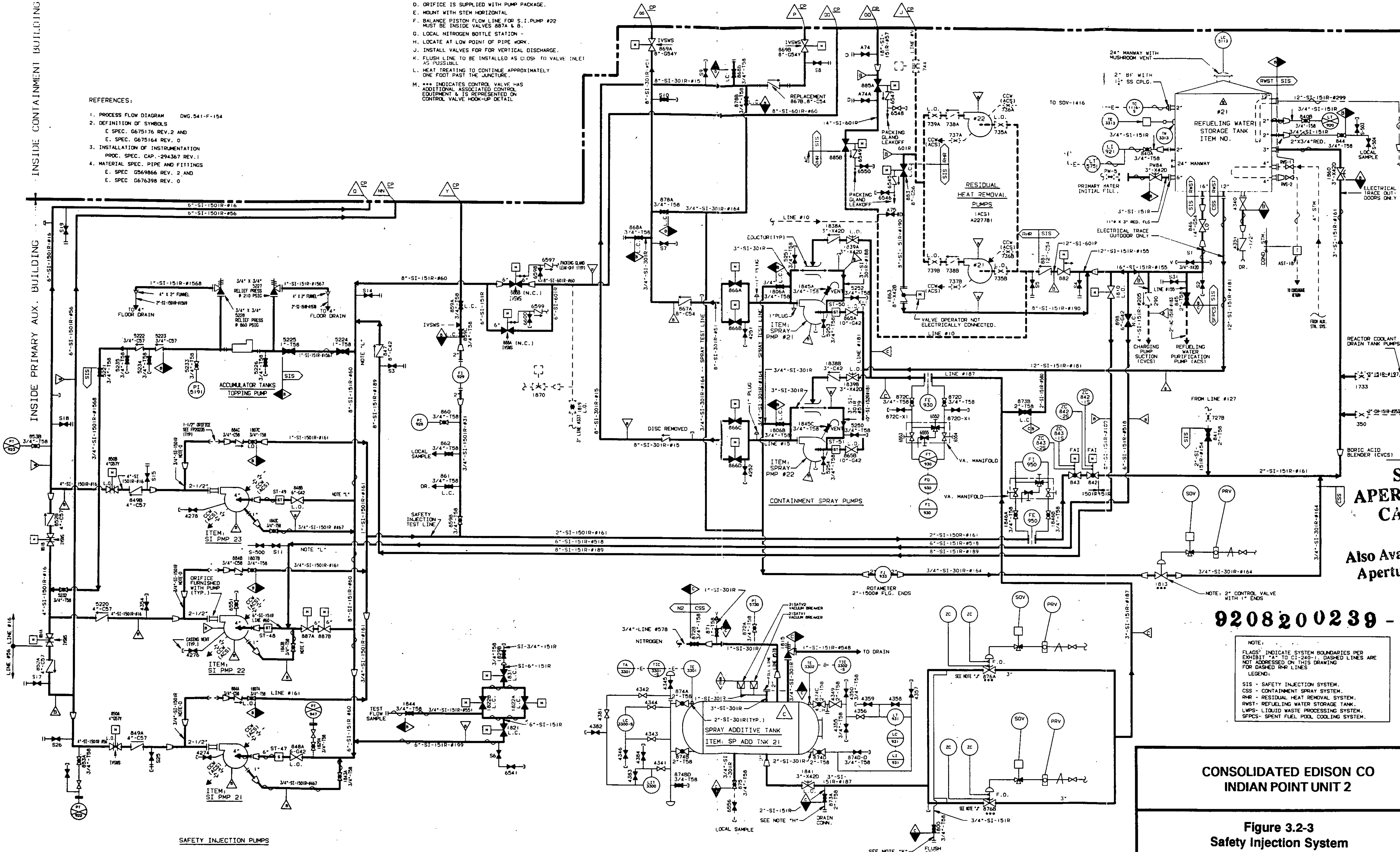
Revision 9

NOTES:

A. PIPING IS SCHEDULE 140
B. LOCATE IN HIGH SIDE OF PIPE IN LOCAL HIGH POINT.
D. ORIFICE IS SUPPLIED WITH PUMP PACKAGE.
E. MOUNT WITH STEM HORIZONTAL
F. BALANCE PISTON FLOW LINE FOR S.I.PUMP #22 MUST BE INSIDE VALVES 887A & B.
G. LOCAL NITROGEN BOTTLE STATION -
H. LOCATE AT LOW POINT OF PIPE WORK.
J. INSTALL VALVES FOR FOR VERTICAL DISCHARGE.
K. FLUSH LINE TO BE INSTALLED AS CLOSE TO VALVE INLET AS POSSIBLE
L. HEAT TREATING TO CONTINUE APPROXIMATELY ONE FOOT PAST THE JUNCTURE.
M. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL

REFERENCES:

1. PROCESS FLOW DIAGRAM DWG.541-F-154
2. DEFINITION OF SYMBOLS
   E SPEC. G675176 REV.2 AND
   E. SPEC. G675164 REV. 0
3. INSTALLATION OF INSTRUMENTATION
   PROC. SPEC. CAP.-294367 REV.1
4. MATERIAL SPEC. PIPE AND FITTINGS
   E. SPEC G569866 REV. 2 AND
   E. SPEC G676398 REV. 0



NOTE:

FLAGS INDICATE SYSTEM BOUNDARIES PER EXHIBIT "A" TO CI-240-1. DASHED LINES ARE NOT ADDRESSED ON THIS DRAWING FOR DASHED RHR LINES

LEGEND:

SIS - SAFETY INJECTION SYSTEM.
CSS - CONTAINMENT SPRAY SYSTEM.
RHR - RESIDUAL HEAT REMOVAL SYSTEM.
RWST- REFUELING WATER STORAGE TANK.
LWPS- LIQUID WASTE PROCESSING SYSTEM.
SFPCS- SPENT FUEL POOL COOLING SYSTEM.

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CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 3.2-3
Safety Injection System
Flow Diagram - Sheet 1

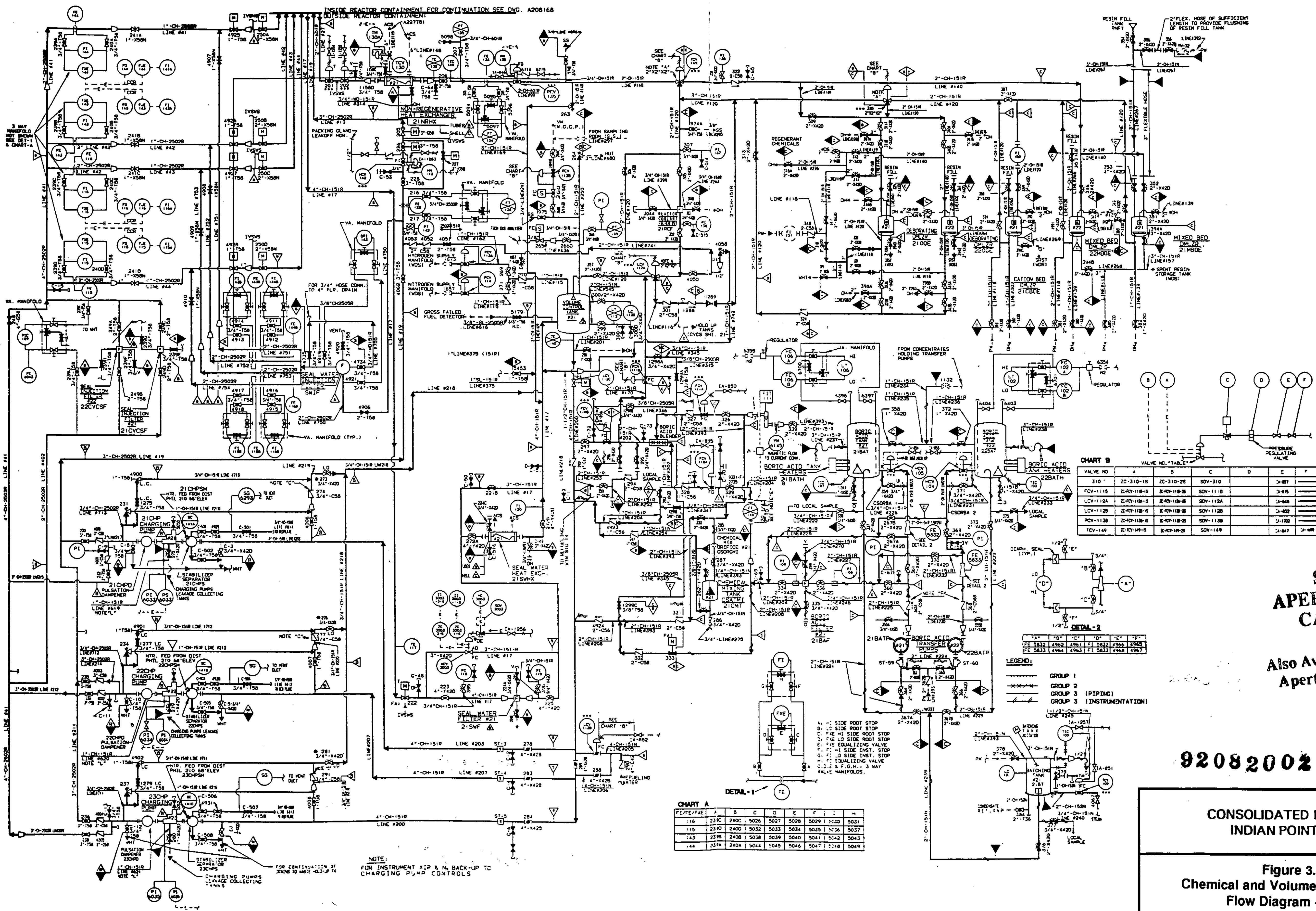

CHART A

FI/FE/FXE	A	B	C	D	E	F	G	H
116	239C	240C	5026	5027	5028	5029	5030	5031
115	239D	2400	5032	5033	5034	5035	5036	5037
143	239B	240B	5038	5039	5040	5041	5042	5043
144	239A	240A	5044	5045	5046	5047	5048	5049

CHART B

VALVE NO	A	B	C	D	E	F
310	ZC-310-1S	ZC-310-2S	SOV-310		IA-857	—
FCV-111B	ZC-FCV-111B-1S	ZC-FCV-111B-2S	SOV-111B		IA-875	—
LCV-112A	ZC-FCV-112A-1S	ZC-FCV-112A-2S	SOV-112A		IA-848	—
LCV-112B	ZC-FCV-112B-1S	ZC-FCV-112B-2S	SOV-112B		IA-852	—
PCV-113B	ZC-FCV-113B-1S	ZC-FCV-113B-2S	SOV-113B		IA-1702	—
TCV-149	ZC-TCV-149-1S	ZC-FCV-149-2S	SOV-149		IA-847	[illegible]

DETAIL-2

"A"	"B"	"C"	"D"	"E"	"F"
FE 5832	4962	4961	FI 5832	4966	4965
FE 5833	4964	4963	FI 5833	4968	4967

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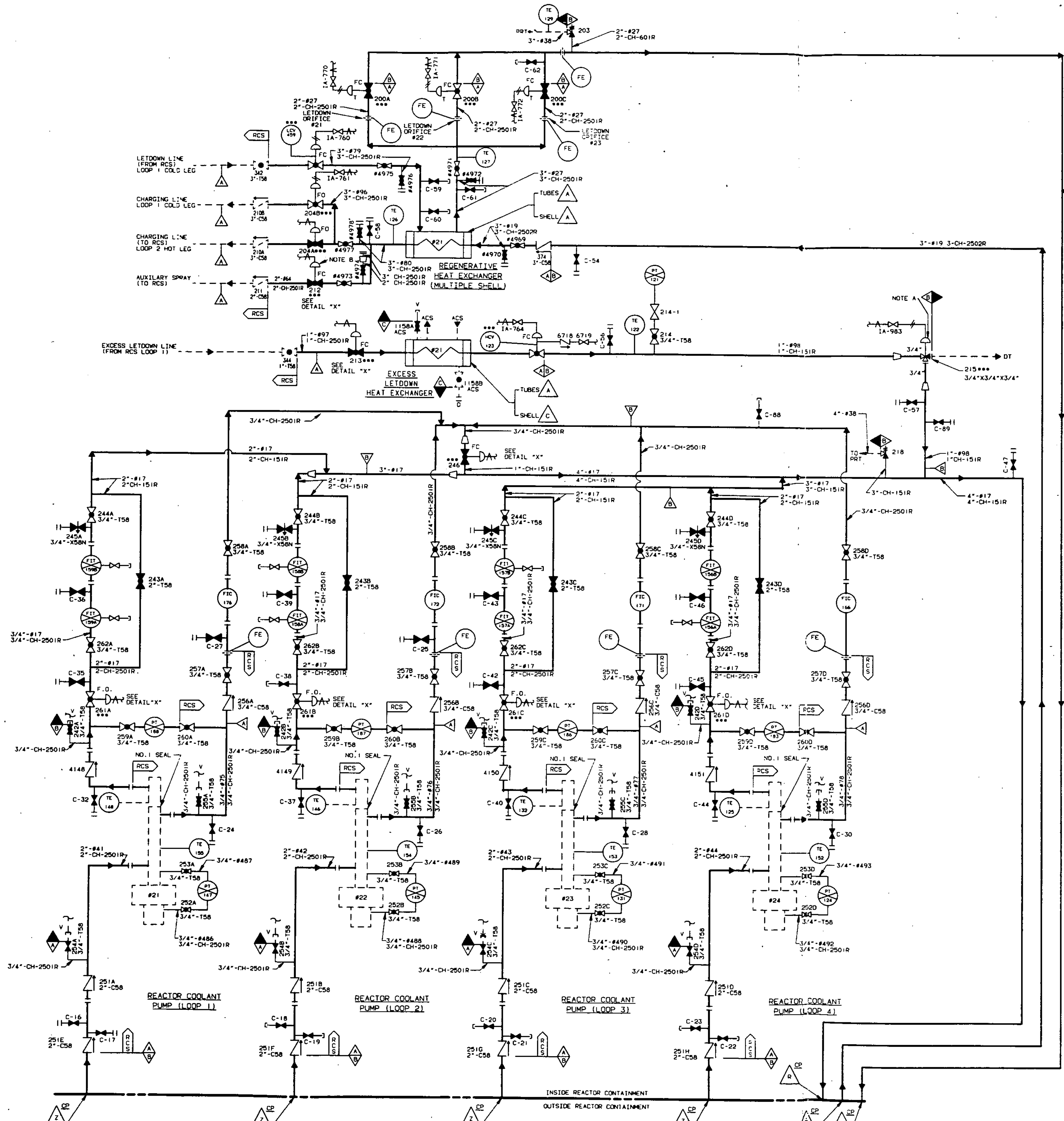
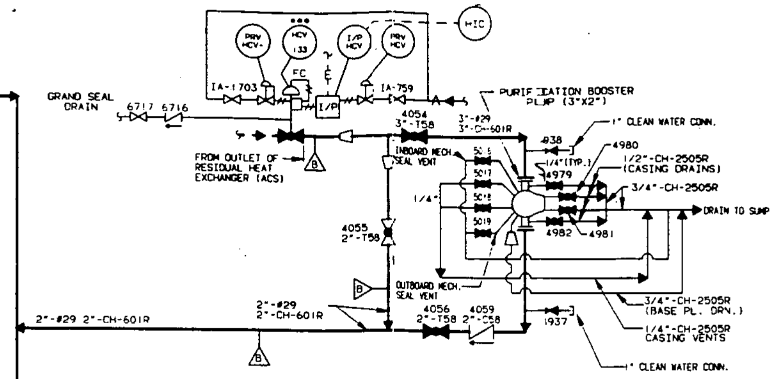
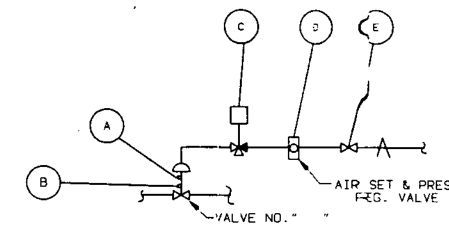
CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 3.2-4
Chemical and Volume Control System Flow Diagram - Sheet 1







VALVE NO	A	B	C	D	E
246	ZC-246-1S	ZC-246-2S	SOV-236		IA-773
261A	ZC-261A-1S	ZC-261A-2S	SOV-211A		IA-766
261B	ZC-261B-1S	ZC-261B-2S	SOV-211B		IA-767
261C	ZC-261C-1S	ZC-261C-2S	SOV-211C		IA-768
261D	ZC-261D-1S	ZC-261D-2S	SOV-211D		IA-769
212	———	———	SOV-212		IA-1312
213	———	———	SOV-213		IA-765

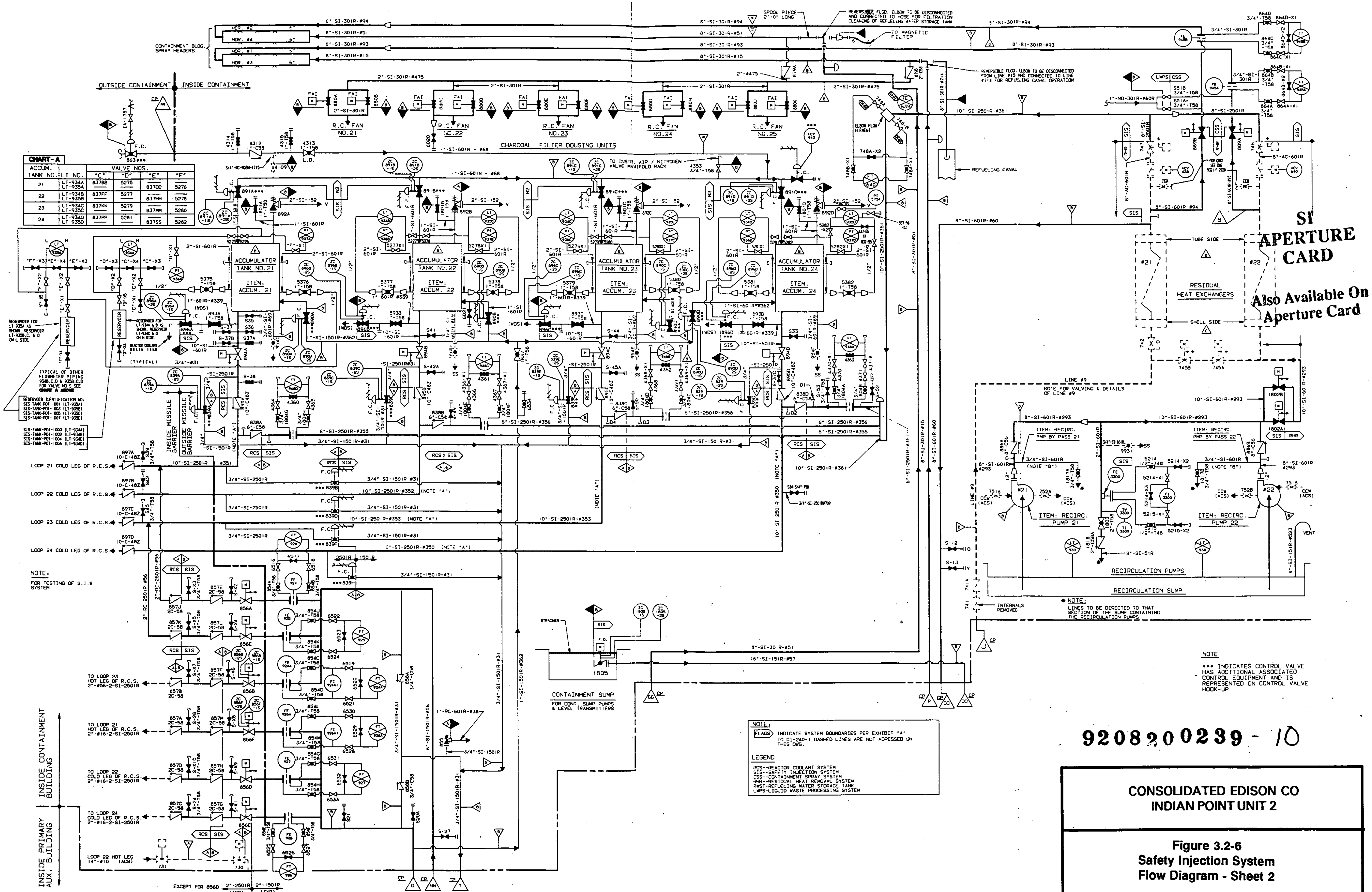
DETAIL X"

NOTES

A. VALVE FAILS WITH FLOW TO VOLUME CONTROL TANK
B. SPECIAL VALVE-FUNCTIONS AS BOTH ISOLATION & RELIEF VALVE.
C. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT & IS REPRESENTED ON CONTROL VALVE HOOK-UP

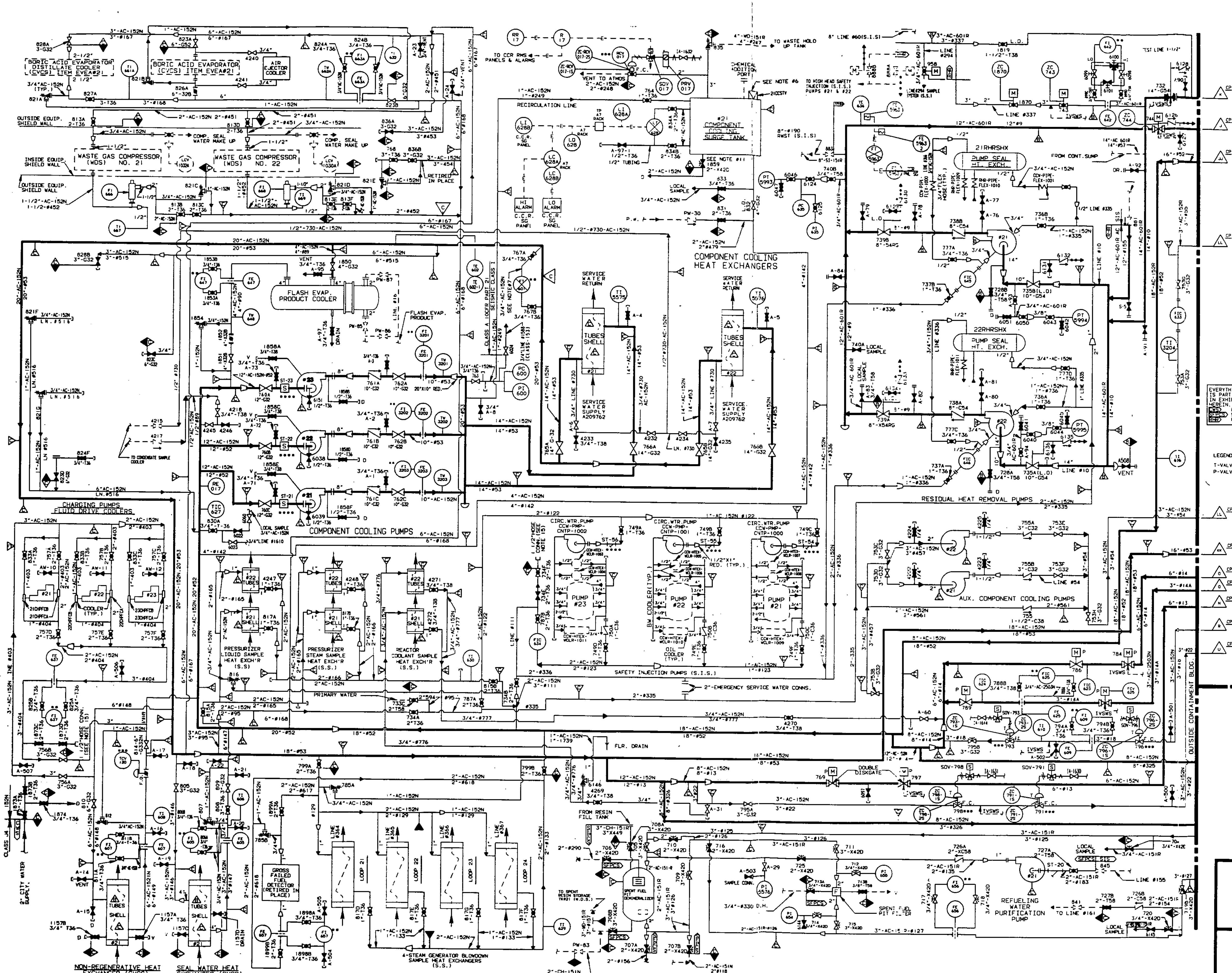
CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 3.2-5
Chemical and Volume Control System
Flow Diagram - Sheet 2



CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 3.2-6
Safety Injection System
Flow Diagram - Sheet 2



INSIDE SPENT FUEL STORAGE BLDG. | OUTSIDE CONTAINMENT BLDG. | INSIDE CONTAINMENT BLDG.

NOTES

1. VALVES ARE NORMALLY INSTALLED WITH FLOW UNDER SEAT, EXCEPT FOR VALVE NO. 831.
2. LOCATE SUCTION CONNECTION IN BOTTOM HALF OF REACTOR COOLANT PIPING ON 45° ANGLE TO VERTICAL.
3. SPRING LOADED CHECK VALVE.
4. LOCATE IN ANNULAR RING BETWEEN SECONDARY SHIELD AND CONTAINMENT WALL.
5. LOCATE VALVE CLOSE TO SPENT FUEL PIT WALL
6. VACUUM BREAKER, SUPPLIED WITH TANK.
7. PRESSURE TAP LOCATED PER Ⓦ I&C STANDARDS.
8. PENETRATE WALL 6 FT. ABOVE FUEL ASSEMBLIES.
9. TERMINATE PIPE 6 FT. ABOVE FUEL ASSEMBLIES.
10. VENT AND DRAIN REQUIREMENT DEPEND UPON PIPING LAYOUT TO BE SPECIFIED BY A.E..
11. ELEVATION OF SURGE TANK NORMAL WATER LEVEL TO BE HIGHEST POINT IN COMPONENT COOLING SYSTEM.
12. REACTOR COOLANT PRESSURE INTERLOCK PREVENTS ISOLATION VALVE OPENING ABOVE SET PRESSURE.
13. SCHEDULE 140 PIPE.
14. FOR MISC. VENTS AND DRAINS REFER TO PHYSICAL PIPING DRAWINGS.
15. HOSE PROVIDED TO ENABLE COOLING WATER TO BE PIPED OUTSIDE THE BUILDING.

17. *** INDICATES CONTROL VALVE HAS ADDITIONAL ASSOCIATED CONTROL EQUIPMENT AND IS REPRESENTED ON CONTROL VALVE HOOK-UP DETAIL
18. ** -INDICATES INSTRUMENT HAS ADDITIONAL VALVES. DETAILS & VALVE IDENTIFICATION
19. **** ST-21, ST-22, ST-23, ST-54, ST-55 AND ST-56 ARE TEMPORARY START-UP STRAINERS WITH INTERNAL SCREENS REMOVED.

EVERYTHING ON THIS DRAWING (EXCEPT FOR DASHED LINES) IS PART OF THE COMPONENT COOLING SYSTEM (CCS) AS DESCRIBED IN EXHIBIT "A" TO CI-240-1, UNLESS OTHERWISE INDICATED HEREIN.

CWS CITY WATER SYSTEM (PORTION NOT LISTED IN CI-240-1)
SFPCS SPENT FUEL POOL COOLING SYSTEM
RHR RESIDUAL HEAT REMOVAL

LEGEND

T-VALVE TO TRIP OR CLOSE ON HIGH CONTAINMENT PRESSURE
P-VALVE TO TRIP OR CLOSE ON HIGH-HIGH CONTAINMENT PRESSURE

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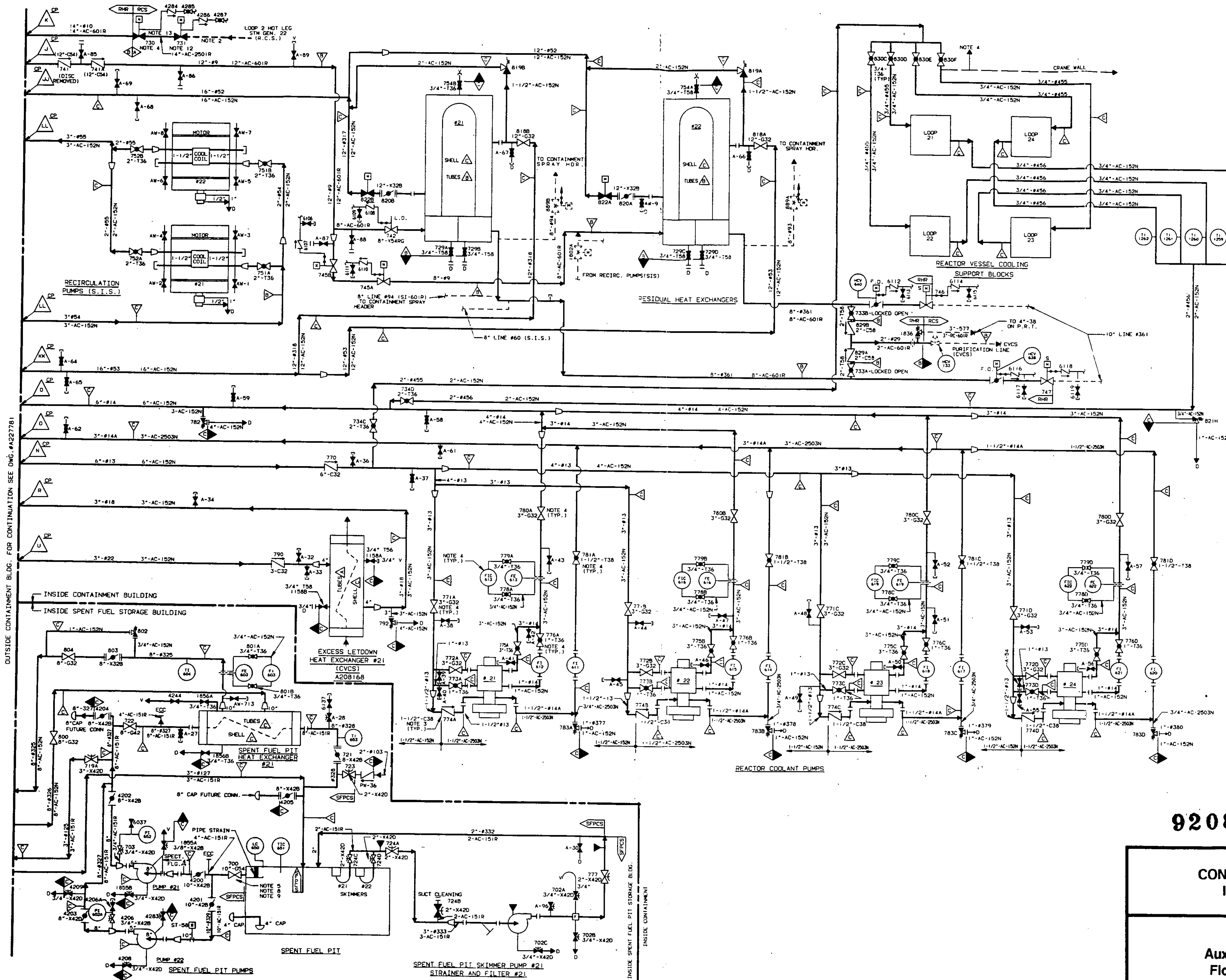
CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 3.2-7
Auxiliary Coolant System
Flow Diagram - Sheet 1



EVERYTHING ON THIS DRAWING (EXCEPT FOR DASHED LINES) IS PART OF THE COMPONENT COOLING SYSTEM AS DESCRIBED IN EXHIBIT A. TO CI-240-1 UNLESS OTHERWISE INDICATED

SFPCS — SPENT FUEL POOL COOLING SYSTEM
RHR — RESIDUAL HEAT REMOVAL SYSTEM
RCS — REACTOR COOLANT SYSTEM

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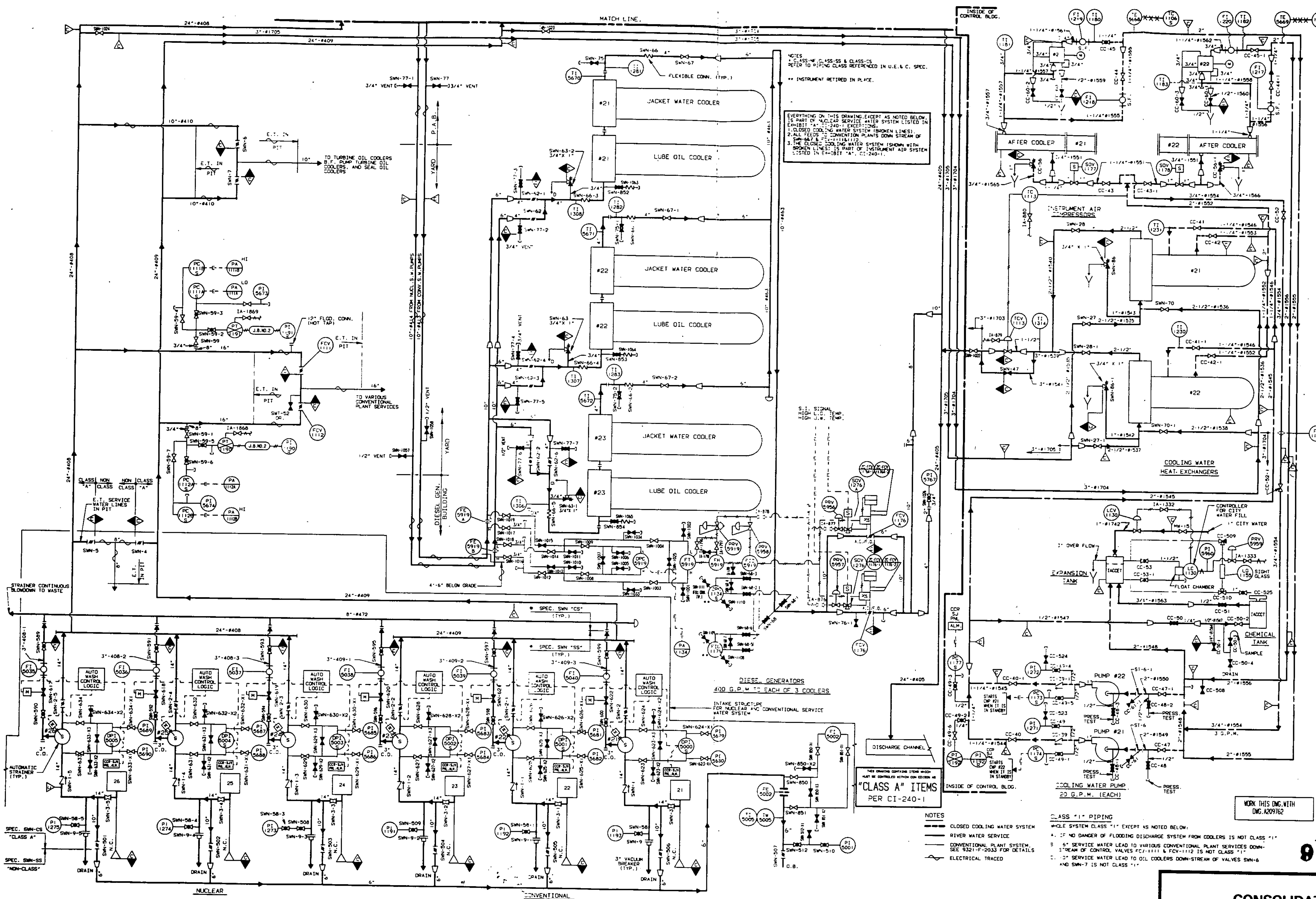
CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 3.2-8
Auxiliary Coolant System
Flow Diagram - Sheet 2



CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 3.2-9
Service Water System
Flow Diagram - Sheet 1

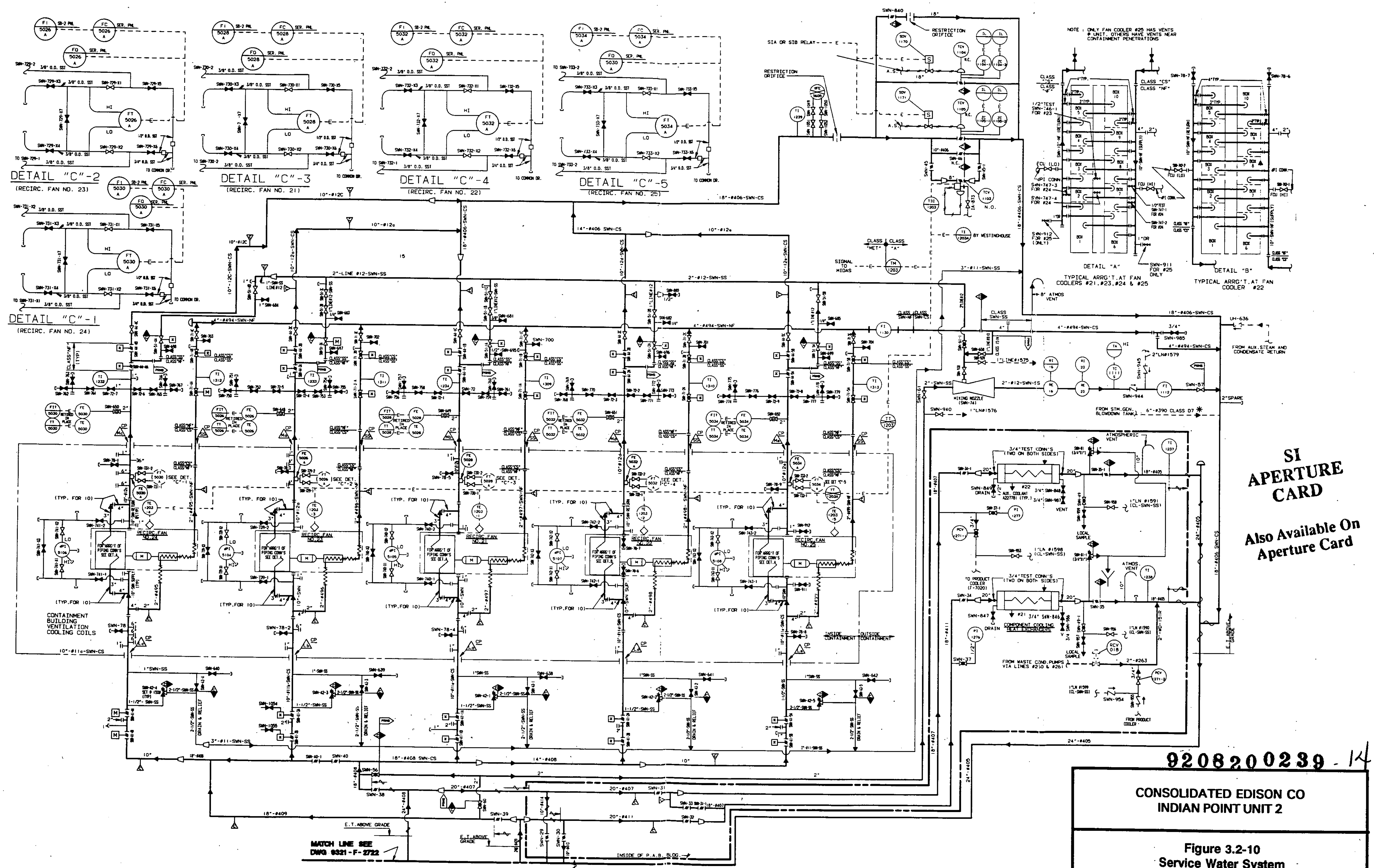


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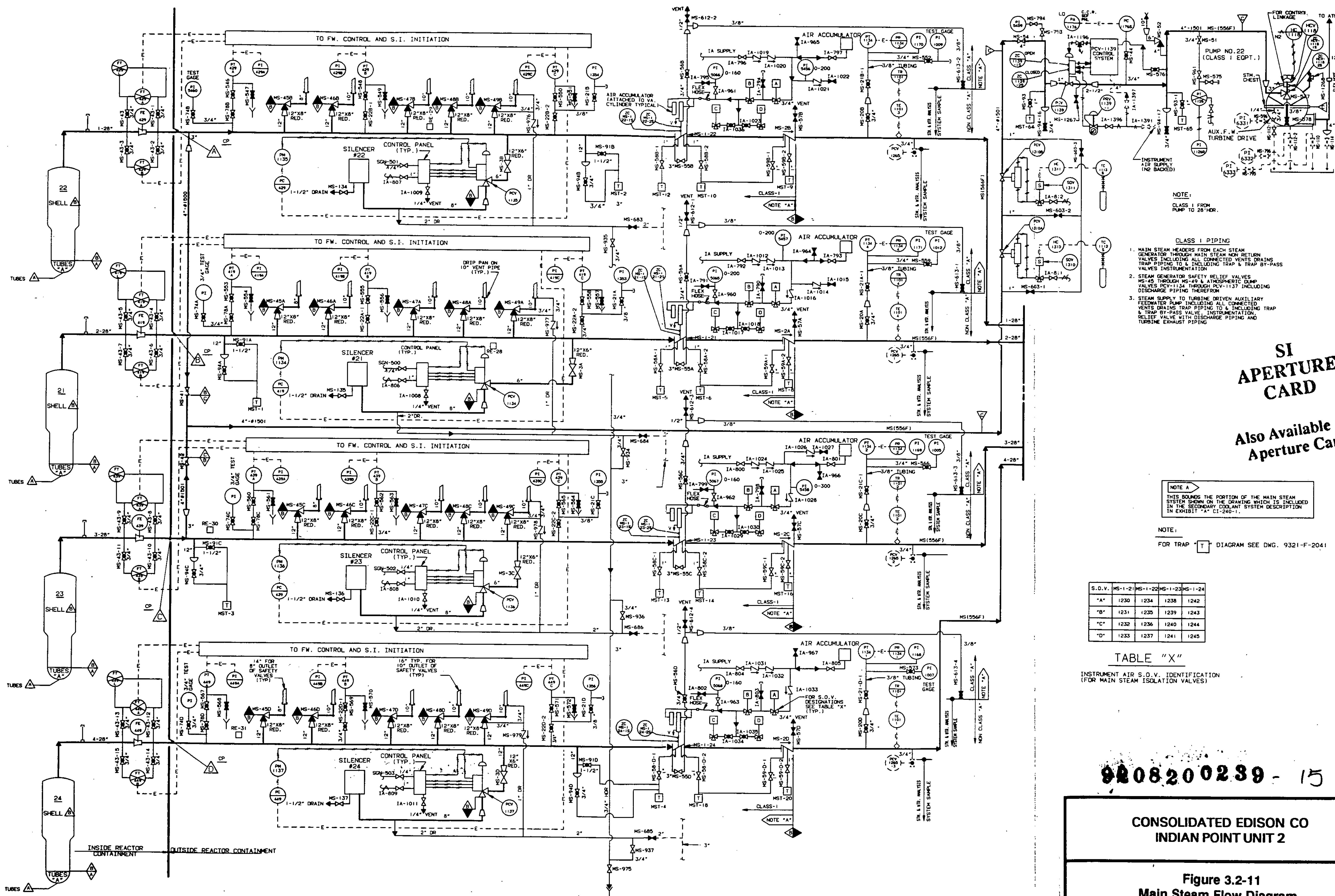
Figure 3.2-10
Service Water System
Flow Diagram - Sheet 2



NOTE:

CLASS I FROM PUMP TO 28'HDR.

CLASS I PIPING

1. MAIN STEAM HEADERS FROM EACH STEAM GENERATOR THROUGH MAIN STEAM NON RETURN VALVES INCLUDING ALL CONNECTED VENTS DRAINS TRAP PIPING TO & INCLUDING TRAP & TRAP BY-PASS VALVES INSTRUMENTATION
2. STEAM GENERATOR SAFETY RELIEF VALVES MS-45 THROUGH MS-49 & ATMOSPHERIC DUMP VALVES PCV-1134 THROUGH PCV-1137 INCLUDING DISCHARGE PIPING THEREFROM
3. STEAM SUPPLY TO TURBINE DRIVEN AUXILIARY FEEDWATER PUMP INCLUDING ALL CONNECTED VENTS DRAINS TRAP PIPING TO & INCLUDING TRAP & TRAP BY-PASS VALVE, INSTRUMENTATION, RELIEF VALVE WITH DISCHARGE PIPING AND TURBINE EXHAUST PIPING

NOTE A

THIS BOUNDS THE PORTION OF THE MAIN STEAM SYSTEM SHOWN ON THE DRAWING WHICH IS INCLUDED IN THE SECONDARY COOLANT SYSTEM DESCRIPTION IN EXHIBIT "A" CI-240-1.

NOTE:

FOR TRAP "T" DIAGRAM SEE DWG. 9321-F-2041

S.O.V.	MS-1-21	MS-1-22	MS-1-23	MS-1-24
"A"	1230	1234	1238	1242
"B"	1231	1235	1239	1243
"C"	1232	1236	1240	1244
"D"	1233	1237	1241	1245

TABLE "X"

INSTRUMENT AIR S.O.V. IDENTIFICATION (FOR MAIN STEAM ISOLATION VALVES)

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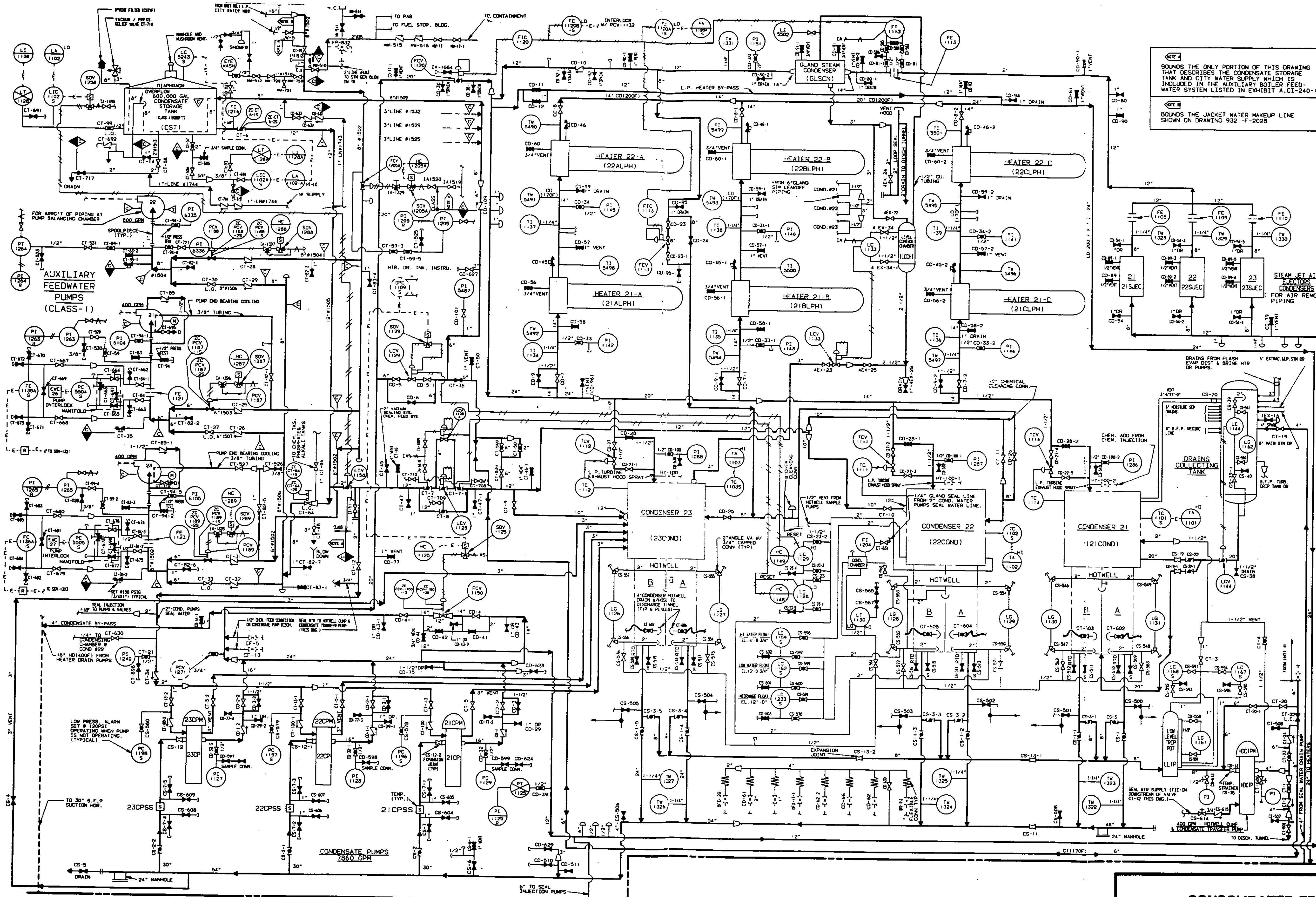
INDIAN POINT UNIT 2

Figure 3.2-11
Main Steam Flow Diagram - Sheet 2



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INDIAN POINT UNIT 2

Figure 3.2-12
Condensate and Boiler Feed Pump Suction - Flow Diagram - Sheet 1

9208200289 - 16

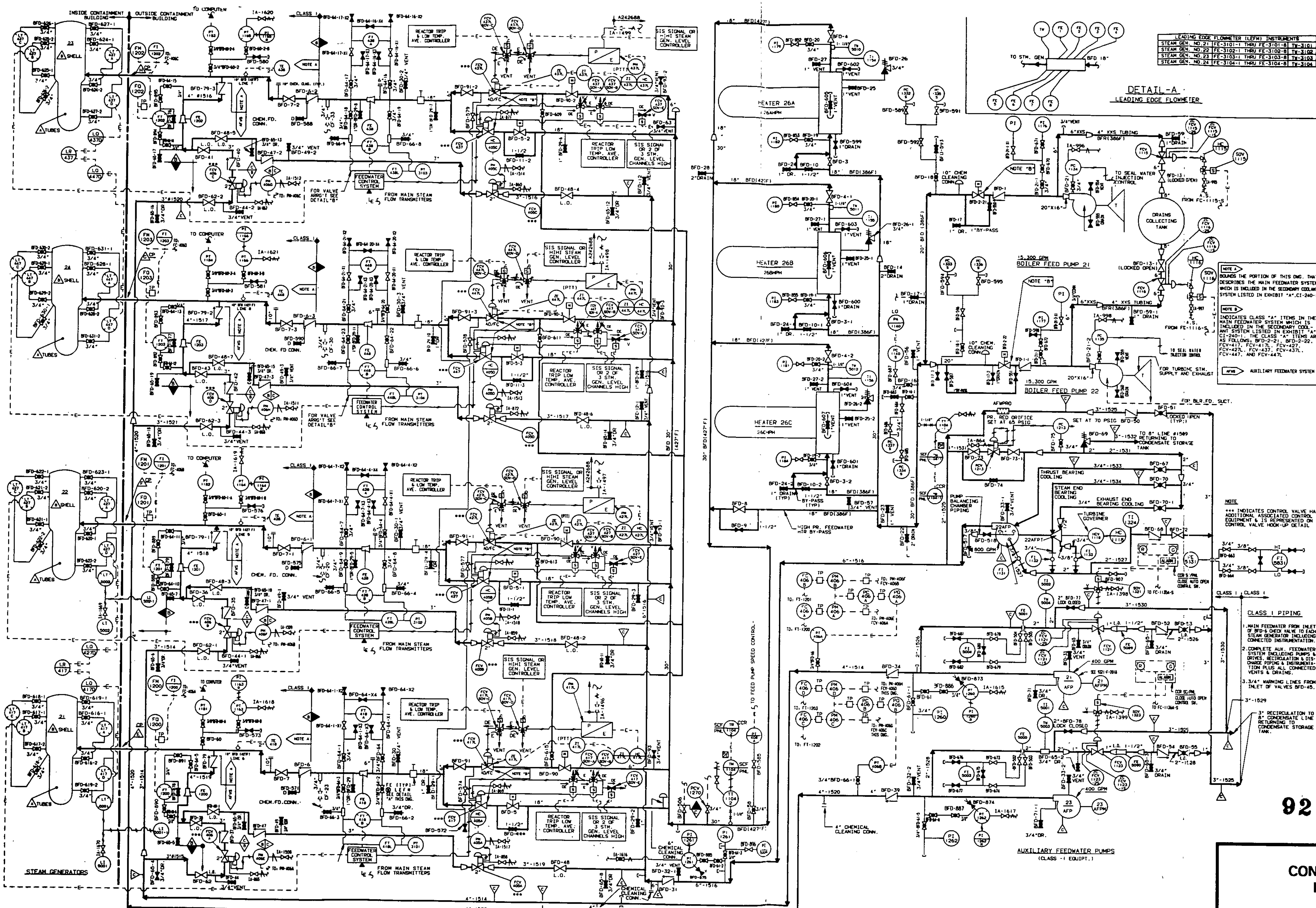

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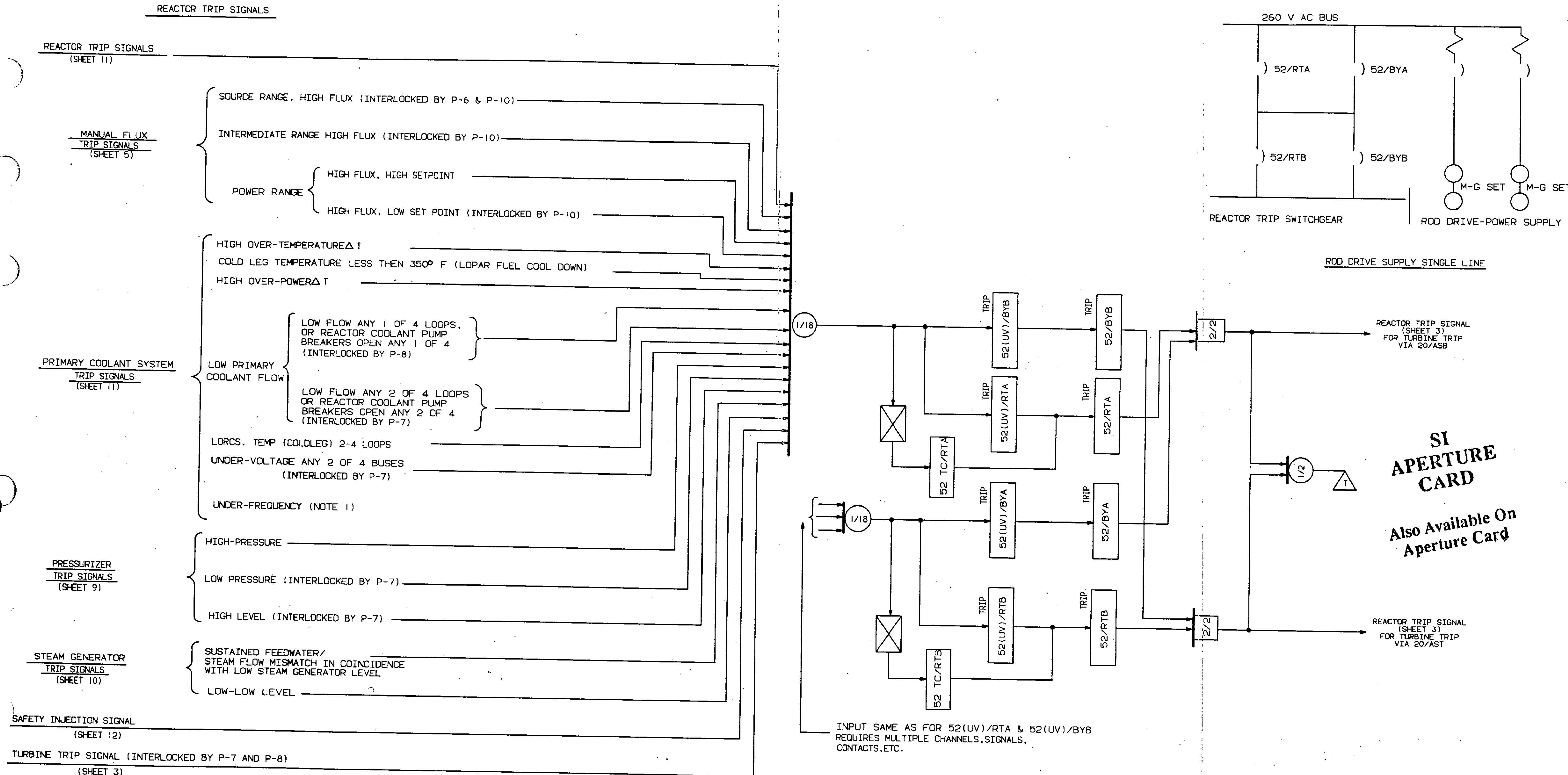
Figure 3.2-13
Boiler Feedwater
Flow Diagram



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NOTES

1 - UNDER-FREQUENCY ON ANY 2 OF 4 BUSES WILL OPEN THE BREAKERS OF ALL REACTOR COOLANT PUMPS AND CONSEQUENTLY CAUSE REACTOR TRIP.

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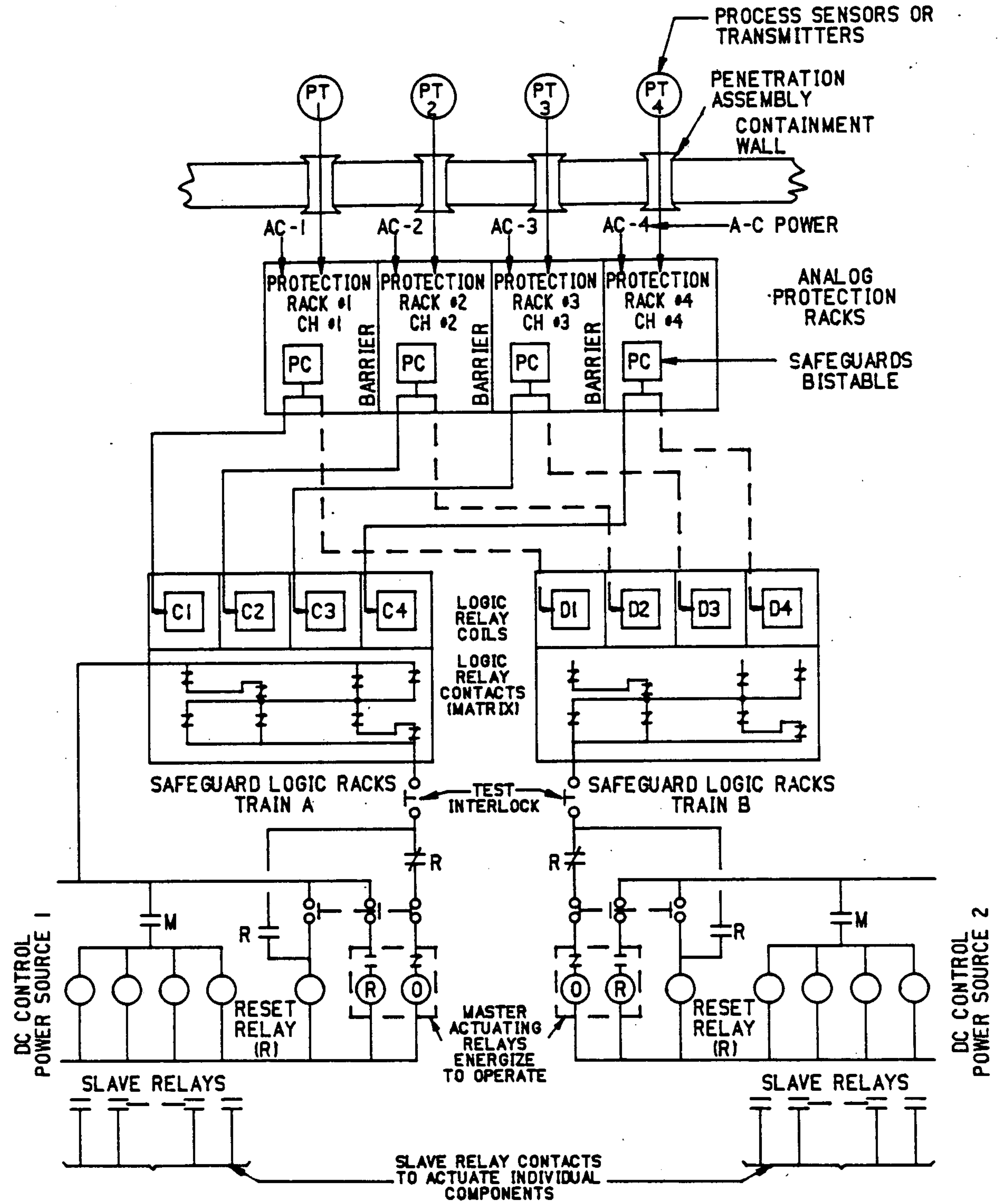
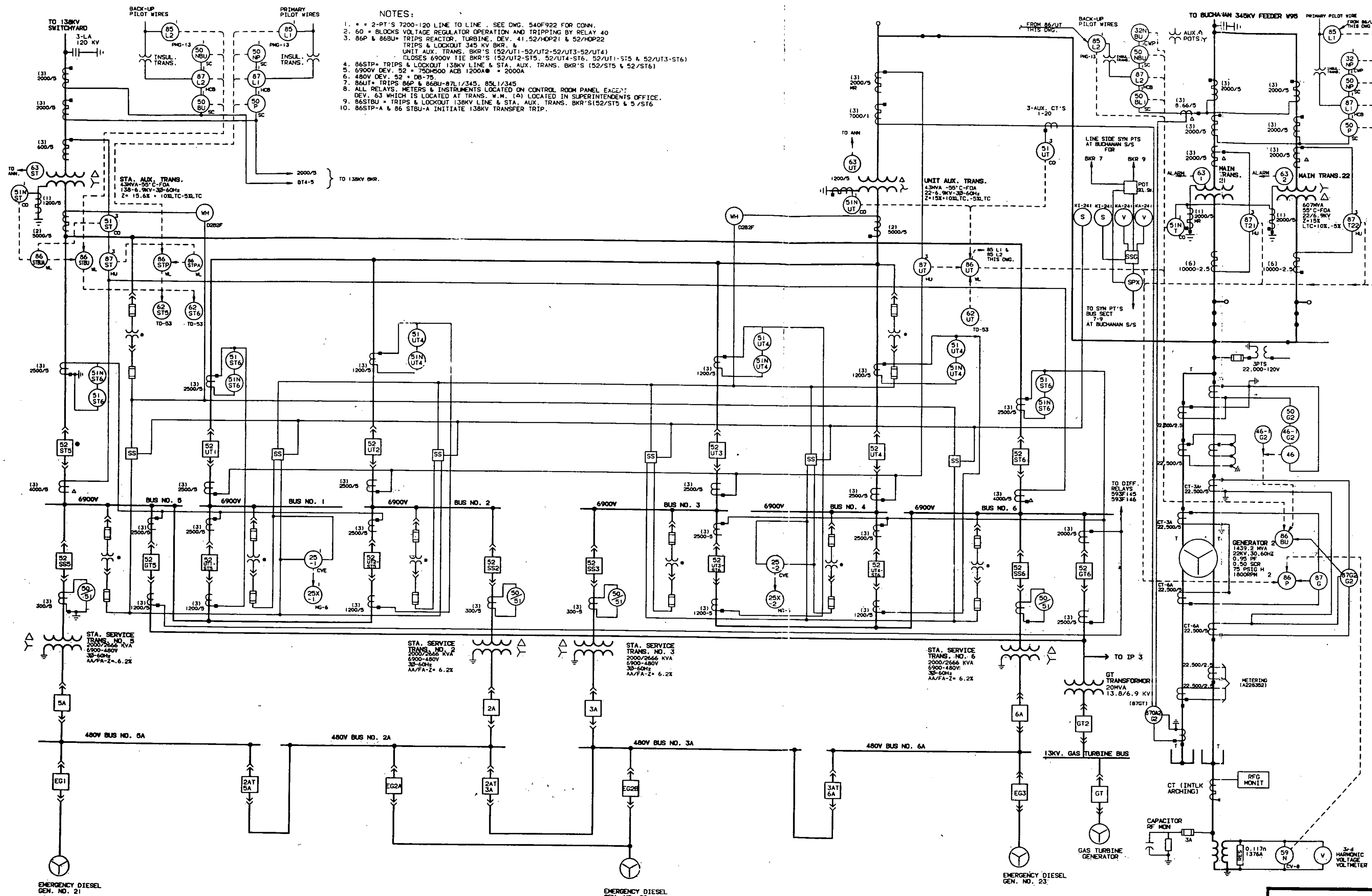
INDIAN POINT UNIT 2

Figure 3.2-14
Reactor Trip Signals
Logic Diagram



SAFEGUARD ACTUATION CIRCUITRY
AND HARDWARE CHANNELIZATION

CONSOLIDATED EDISON CO. INDIAN POINT UNIT 2
Figure 3.2-15 Safeguards Actuation Circuitry and Hardware Channelization



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Also Available On Aperture Card

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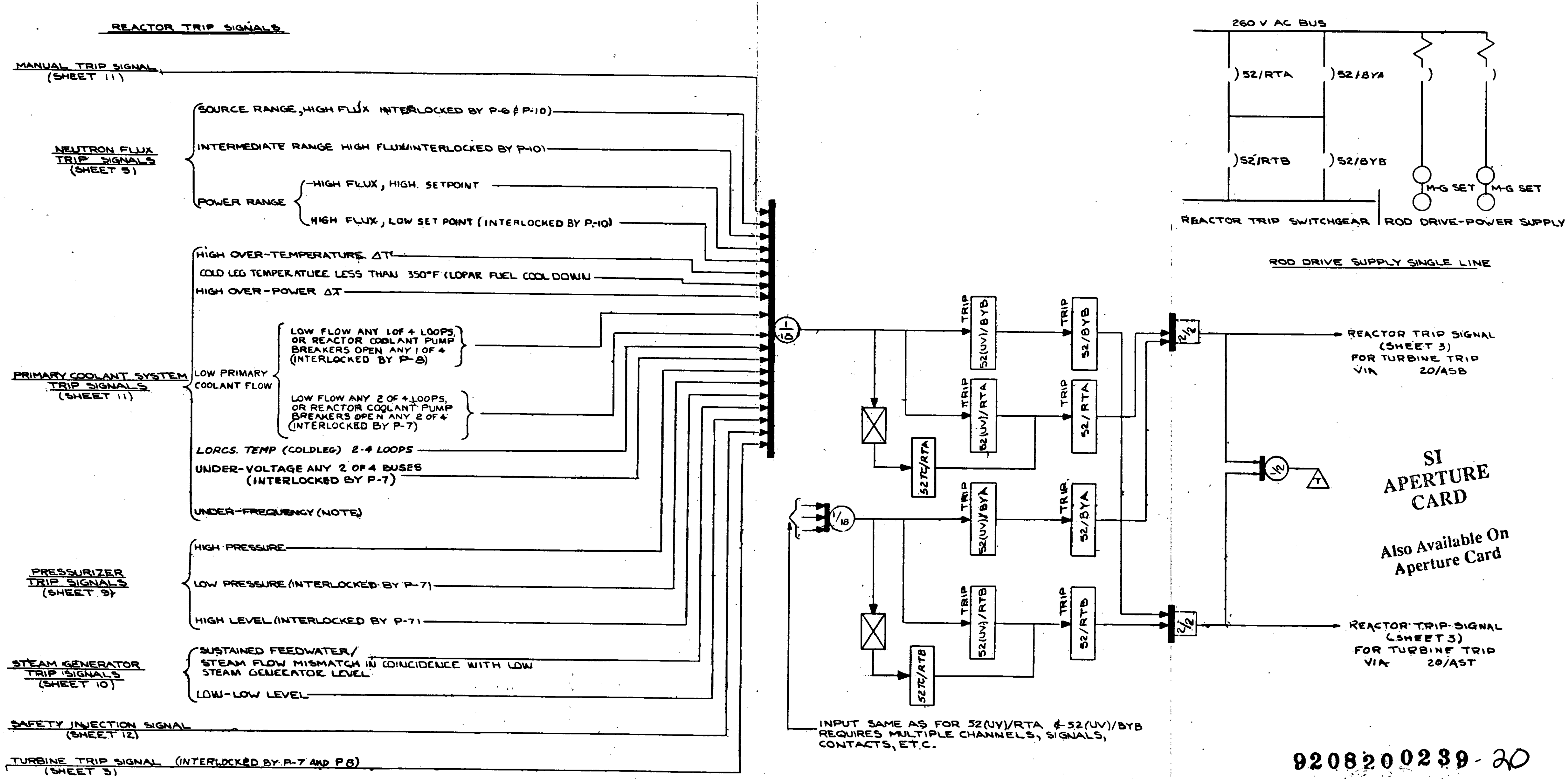
INDIAN POINT UNIT 2

Figure 8.2-3
Main One-Line Diagram

Revision 8



SI APERTURE CARD

Also Available On Aperture Card

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UNDER-FREQUENCY ON ANY 2 OF 4 BUSES WILL OPEN THE BREAKERS OF ALL REACTOR COOLANT PUMPS AND CONSEQUENTLY CAUSE REACTOR TRIP.

CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 3.2-16
Main One-Line Diagram

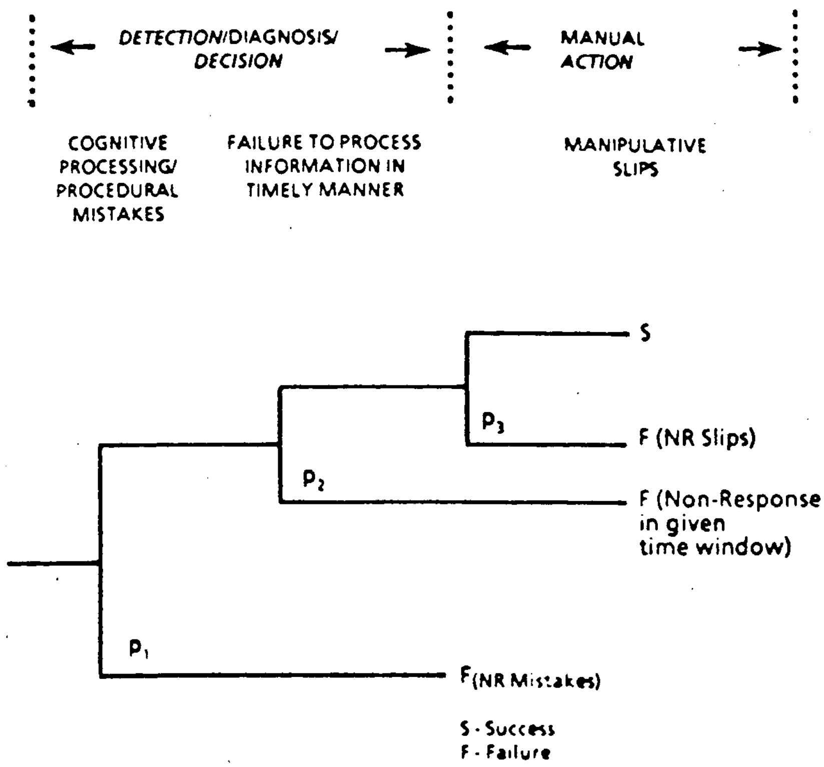


Figure 3.3-1: Generalized Event Tree Representation of Post Accident Operator Actions

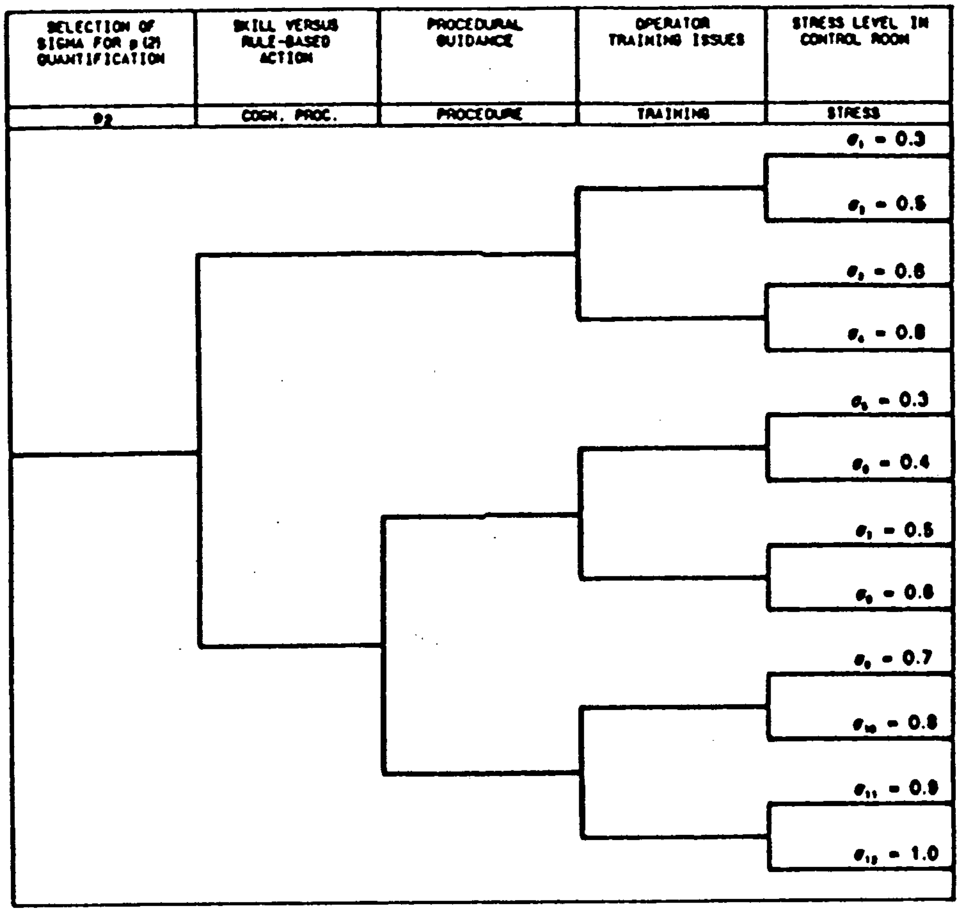
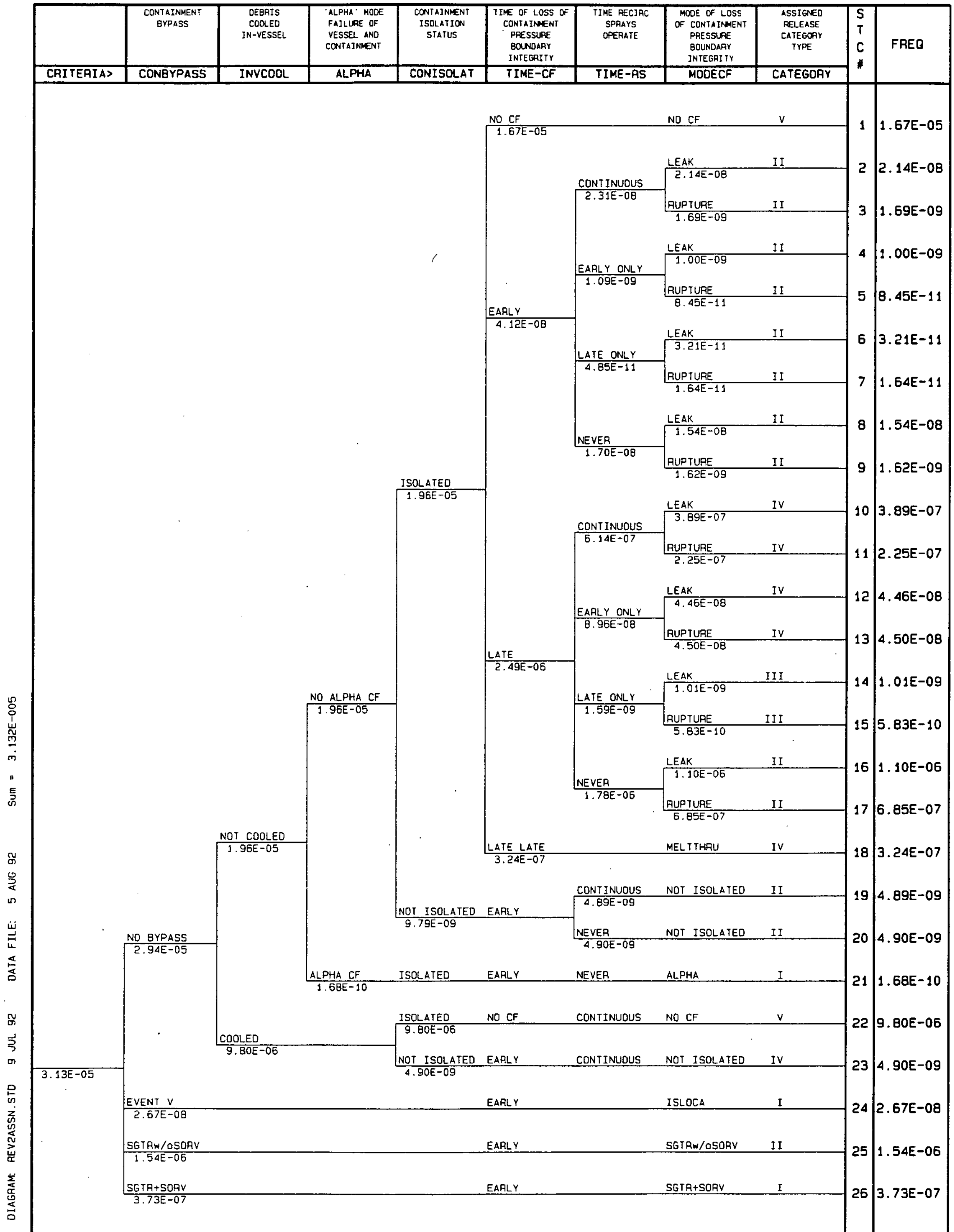


Figure 3.3-2: Decision Tree for Modified ORE/HCR Correlation



CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

SOURCE TERM CATEGORY GROUPING DIAGRAM

Figure 3.4-1

SECTION 4.0

CONTAINMENT RESPONSE (LEVEL 2 "BACK-END") ANALYSIS

4.0 CONTAINMENT RESPONSE (LEVEL 2 "BACK-END") ANALYSIS

This chapter presents the analysis of the Containment Building (Containment) response to severe accidents. The accident data are treated on the bases of internal event initiators with and without including internal flooding initiators. The first seven sections are generally organized as requested in NUREG-1335. A further section is added here to present sensitivity analyses results.

Section 4.1 identifies and highlights the component, system, and structure data that is of significance in assessing severe accident progressions.

Section 4.2 discusses the MAAP plant analytical model and the selection of empirical factor and data inputs.

Section 4.3 covers the coupling of the front-end (Level 1) analysis to the back-end (Level 2) analysis, through the binning of the Level 1 accident sequences, extended to include Containment systems, into plant damage states with similar back-end characteristics.

Section 4.4 characterizes the Containment strength assessment and the magnitude of various loads necessary to fail Containment.

Section 4.5 delineates the Containment event trees which characterize the possible paths that an accident sequence may progress along, given the sets of initial conditions defined by the various plant damage states. The decomposition event trees that expand on each of the Containment event tree headings are presented. These ancillary trees include the numerical expression of the judgment of the phenomenological uncertainties ("split fractions") and it is convenient to present these split fraction assessments in this section. The methods and the results of the Containment event tree probabilistic analyses (quantification) are also in this section.

Section 4.6 describes the deterministic Containment accident progression analyses performed to support the Containment event tree development and quantification and to provide insights and information on the plant response.

Section 4.7 presents the radionuclide release source term development, analyses, and numerical results.

Section 4.8 discusses the results of a structured sensitivity analysis performed to identify the significant sensitivities to phenomenological probability variations and to assess the impact of variation in Level 1 results on the overall Level 2 results.

SECTION 4.1

PLANT DATA AND PLANT DESCRIPTION

4.1 Plant Data and Plant Description

This section provides a summary of the important IP2 design data and a description of the plant features relevant to the Level 2 analysis. Tables 4.1-1 thru 4.1-3 present data for the IP2 core and primary containment.

4.1.1 General Containment Building Structure

The reactor containment structure is a reinforced concrete, vertical, right cylinder with a flat base and hemispherical dome. The reactor containment has a free volume of 2,610,000 ft^3 and completely encloses the entire reactor and reactor coolant system. The design objective of the containment structure is to contain all radioactive material which might be released from the core following a loss-of-coolant accident. The structure, as shown on Figures 4.1-1 through 4.1-6, serves as both a biological shield and a pressure container.

The containment structure consists of a base slab, side walls, and dome acting as one structure. The side walls measure 148 feet from the base to the springline of the dome, and has an inside diameter of 135 feet. The side walls for the cylinder and the dome are 4 feet 6 inches and 3 feet 6 inches thick respectively. The inside radius of the dome is equal to the inside radius of the cylinder so that there is no inner surface discontinuity at the springline due to the change in thickness.

The flat concrete base mat is 9 ft thick with the bottom liner plate located on top of this mat. The bottom liner plate is covered with 3 ft of concrete, the top of which forms the floor of the containment. The reactor cavity concrete chemical analysis (w/o) is as follows:

	Sidewall %	**Floor** %
Al_2O_3	15.8	14.3
SiO_2	33.8	36.6
Fe_2O_3	1.3	2.9
CA O	36.6	21.9
Free H_2O	2.2	6.1

Reinforcing steel for the dome, cylindrical walls and base mat is high-strength, deformed billet steel bars. This steel has a minimum yield strength of 60,000 psi, a minimum tensile strength of 90,000 psi, and a minimum elongation of 7 per cent in an 8-in. specimen. Reinforcing bars No. 11 and smaller in diameter are lapped spliced in the mat for flexural loadings and spliced by the Cadweld process in the walls and dome for tension loading. Bars No. 14S and 18S are spliced by the Cadweld process. The plate steel liner is carbon steel and has a minimum yield strength of 32,000 psi and a minimum tensile strength of 60,000 psi with an elongation of 22 percent in an 8-in. gauge.

Structures internal to the reactor containment include equipment supports, shielding, reactor cavity and canal for fuel transfer, and miscellaneous concrete and steel for floors and stairs. All internal structures are supported on the basemat with the exception of equipment supports secured to the intermediate floors. Information describing the structural heat sinks within the Containment is provided in Table 4.1-3.

A three foot thick concrete ring wall serving as a missile and partial radiation shield surrounds the reactor coolant system components and supports the polar-type reactor containment crane. A two foot thick reinforced concrete floor at approximately the 95 foot elevation covers the reactor coolant system with removable gratings in the floor provided for crane access to the reactor coolant pumps. The four steam generators, the pressurizer, and various piping penetrate this floor. Stairs provide normal access to the areas below this elevation. A reinforced missile shield surrounds the portion of the pressurizer that extends above this operating floor.

A welded steel liner is attached to the inside face of the concrete shell and acts as a vapor barrier to ensure a high degree of leaktightness. The liner is 0.25 inches thick at the bottom, 0.50 inches thick in the first three courses (except 0.75 inches thick at penetrations), and 0.375 inches thick for the remaining portion of the cylindrical walls. The liner is 0.50 inches thick in the dome. The liner is anchored to the concrete shell by means of stud anchors.

All piping systems that penetrate the vapor barrier are anchored at the liner. The penetrations for the main steam, feedwater, blowdown, and sample lines are designed so that the penetration is stronger than the piping system. All lines connected to the primary coolant system that penetrate the vapor barrier are also anchored in the secondary shield walls (i.e., walls surrounding the steam generators and reactor coolant pumps) and are each provided with at least one valve between the anchor and the reactor coolant system. These anchors are designed to withstand the thrust, moment, and torque resulting from a hypothesized rupture of the attached pipe.

4.1.2 Primary Auxiliary Building

The Primary Auxiliary Building houses systems which provide safety, control and support functions to the primary system during both normal and transient or accident conditions. These systems include, among others, the High and Low Pressure Injection Systems, the Containment Spray System, the Component Cooling Water System, the Charging System and portions of the Electrical Distribution System. The majority of the containment penetrations are located in areas which communicate directly with the Primary Auxiliary Building and utilize a common filtered release point. General arrangement drawings for the PAB are provided in Figures 4.1-7 and 4.1-8.

The lower levels of the PAB and some portions of the upper levels utilize concrete exterior walls. The remaining portions of the upper levels utilize siding covering a steel superstructure. Although the PAB ventilation system is designed to assure monitored, controlled releases of airborne activity and includes both high efficiency and carbon filter units, no credit has been taken in the original IPPSS or in the IPE for radionuclide scrubbing or retention in the PAB.

SECTION 4.2

PLANT MODELS AND METHODS FOR PHYSICAL PROCESSES

4.2 Plant Models and Methods for Physical Processes

The Modular Accident Analysis Program (MAAP) was used in the Indian Point 2 IPE Containment evaluation for the accident progression analysis, to assist in quantifying the CET, and for estimating source terms. Information from prior analyses (principally the NUREG-1150 work, especially for Surry and also the previous IPPSS studies) was also utilized.

4.2.1 MAAP Analysis Assumption (Model Parameters)

The MAAP model parameters generally represent inputs to phenomenological models in which significant uncertainties exist. Variation in the values of these parameters can be used to assess the impact of uncertainties in important physical models. The nominal, or default, values of these parameters are generally the code developers best estimate for the value of the model parameter. These values are shown in the MAAP User's Manual (Ref. 4.2-1) and also contained in the MAAP User's Guide (Ref. 4.2-2).

For most model parameters the default values have been used for base case analysis in the Indian Point 2 IPE. The following MAAP model parameter input was varied from the default values.

FCRBUC - MAAP in-core blockage model parameter

This parameter activates/deactivates the IDCOR blockage model in the core. Selection of this model stops oxidation and gas flow through a node at the onset of melting in that node. Use of this model tends to greatly reduce hydrogen production. For the base case calculations for Indian Point 2 this model has been deactivated. Hence, predicted hydrogen production would be expected to be on the same level as predicted by the Source Term Code Package.

4.2.2 References for Section 4.2

4.2-1 "PWR Westinghouse Large Dry MAAP Users Guide", Fauske and Associates, May 1990

4.2-2 "Modular Accident Analysis Program (MAAP) 3.0B Users Manual", Fauske and Associates, March 1990.

SECTION 4.3

BINS AND PLANT DAMAGE STATES

4.3 Bins and Plant Damage States

The interface between the Level 1 Systems Analysis and the Level 2 Containment Analysis consists of a set of plant damage states (PDS). The plant damage states are defined by a set of functional characteristics for system operation which are important to accident progression, Containment failure and source term definition. Each PDS contains Level 1 sequences with sufficient similarity in system functional characteristics that the Containment accident progression for all sequences in the group can be considered to be essentially the same. Each PDS defines a unique set of conditions regarding the state of the plant and Containment Building systems and the physical state of the core, Primary Coolant System and the Containment boundary at (approximately) the time of core damage/vessel failure. The important functional characteristics for each PDS were determined by defining the critical parameters (system functions) which impact the key results. The sequence characteristics which are important were defined by the requirements of the Containment accident progression analysis. They include the type of accident initiator, the operability/non-operability of important systems, the value of important state variables (e.g., Primary System pressure) which are defined by system operation, and timing of key events.

The Indian Point 2 PDS (Level II) Logic Diagram is shown in Figure 4.3-1, which shows the frequency of each plant damage state as input to the Level 2 analysis.

The Level 2 PDS set are a collapsed version of the original PDS set derived in the Level analysis. Further detailed discussion of the Level 1 sequence binning process is provided in section 3.1.6. Individual sequence contributors to important PDSs are provided in section 3.4.

SECTION 4.4

CONTAINMENT BUILDING FAILURE CHARACTERIZATION

4.4 Containment Building Failure Characterization

The containment structure is a reinforced concrete vertical right cylinder with a flat base and hemispherical dome. A welded steel liner with a minimum thickness of 1/4 inch is attached to the inside face of the concrete to ensure a high degree of leak-tightness. The design objective of the containment structure is to contain all radioactive material which might be released from the core following a loss-of-coolant accident. The structure serves as both a biological shield and a pressure containment.

The structure consists of side walls measuring 148 feet from the liner on the base to the springline of the dome, and has an inside diameter of 135 feet. The side walls of the cylinder and the dome are 4 feet 6 inches and 3 feet 6 inches thick, respectively. The inside radius of the dome is equal to the inside radius of the cylinder so that the discontinuity at the springline due to the change in thickness is on the outer surface. The flat concrete base mat is 9 feet thick with the bottom liner plate located on top of this mat. The bottom liner plate is covered with 3 feet of concrete, the top to which forms the floor of the containment.

There are two large openings in the Indian Point Containment Structures. A 16 ft diameter equipment hatch is located in the north east quadrant at a center line elevation of 101'6 and a 8'6 diameter personnel lock is in the south east quadrant at a center line elevation of 83'6. Both are constructed of ASTM 516 GR 60 steel and are anchored into reinforced concrete bosses by means of stud anchors. The reinforced concrete bosses are thickened to 7'6 at the equipment hatch and 5'6 at the personnel lock. The steel liner plate is thickened to 3/4" in the area adjacent to the penetrations and is anchored into the concrete by hooked L-anchors. The thickened boss is heavily reinforced in addition to the dense reinforcement which already exists in the 4 feet 6 inches thick Containment cylinder wall.

4.4.1 Containment Building Failure Modes

The Containment Building failure modes identified for Indian Point 2 are derived from the analyses discussed in Section 4.4.2 below. NUREG-1335 gives a list of potential Containment failure modes and mechanisms and states that all of these failure modes and mechanisms were considered in NUREG-1150. The following text discusses each of these items.

Direct Bypass

Direct bypass of the Containment is considered in the Indian Point 2 IPE. The bypass sequences include both V-sequence and Steam Generator tube rupture (SGTR)-initiated sequences as well as induced SGTR cases.

Failure to Isolate

A leak in Containment either existing at the time of the accident or resulting from the failure of the isolation paths to close may result in a significant release pathway especially if the path is in direct contact with the Containment atmosphere. The Indian Point 2 IPE has considered this issue. An IP2 Level 1 study shows that loss of isolation sequences involve piping with cross section areas less that 1 ft^2 and that piping with areas greater than 1 ft^2 can be screened out. The failure probability derived by a screening and modeling analysis of the potential pathways for the failure of the normally open lines in contact with the Containment atmosphere. The probability of containment isolation failure for all PDS sequences was assigned a constant value of 4.68×10^{-4} (rounded up to 0.0005).

Vapor Explosions

There is a substantial body of evidence to suggest that in-vessel steam explosions do not represent a credible threat to early containment failure (i.e., the probability of early containment failure resulting from in-vessel steam explosions is negligibly small). This opinion appears to be shared by the authors of Appendix 1 to Generic Letter 88-20. However, since in-vessel steam explosions were considered in the NUREG-1150 containment analysis for Surry (NUREG/CR-4551, Ref. 4.4-1) and because this event, if it should occur, can result in large and early environmental releases, this event has been included in the IP-2 IPE.

Ex-vessel steam explosions were dismissed for the Surry plant in NUREG-1150 because steam explosions in the cavity would not directly contact structures that are both vulnerable and essential to the containment function. Based on the NUREG-1150 reasoning, containment failure resulting directly from ex-vessel steam explosions was not considered in the Indian Point 2 IPE.

Combustion Processes

The combustion of hydrogen prior to reactor vessel breach was treated in NUREG-1150 as an expert elicitation issue. However, it was decided that hydrogen combustion is of much greater concern for lower capacity containments [Boiling Water Reactor (BWR) plants and ice condenser PWR plants] than it is for large high capacity containments such as Surry (and Indian Point 2). In the words of NUREG-1150: "... the importance of early hydrogen combustion to the uncertainty in reactor risk for these plants is minor in comparison to that observed in the Grand Gulf and Sequoyah analyses."

Nonetheless, hydrogen combustion was considered in the Surry NUREG-1150 accident progression analysis. Both early and late combustion were considered. Since the Surry Containment Building was found to be robust by the structural experts, the possibility of Containment failure prior to reactor vessel failure is so remote as to be considered negligible and was not included in the NUREG/CR-4551 Surry Containment Building event analysis. The failure of containment due to a hydrogen burn at the time of reactor vessel failure or subsequent to vessel failure was considered likely enough to be included. As has been mentioned previously, the strengths of the IP-2 and the Surry containments are comparable so that the same considerations would apply.

In the Indian Point 2 IPE Containment analyses the impact of hydrogen combustion on Containment overpressurization was considered at vessel failure and late in the accident sequence after vessel failure. Based on the results from NUREG-1150, global detonations were considered of negligible importance and were not included in the Indian Point 2 IPE Containment analysis. The late Containment failure modes are basemat melt-through or gradual steam overpressurization failures.

The effects of local hydrogen combustion on equipment is accounted for in the quantification of the effect of the containment environment on the spray pumps and fan coolers. Because of the diversity and redundancy of these systems, local hydrogen burns is not expected to have a significant impact on the failure probability.

Steam Overpressurization

Gradual pressurization of the Containment Building would result from the protracted generation of steam and non-condensible gases from the interaction of molten core material with water on the Containment floor or with the concrete basemat. This pressurization process could last from several hours to several days, depending upon accident-specific factors such as the availability of water in the Containment and the operability of engineered safety features.

Gradual Containment pressurization by steam production and from the non-condensible gases generated during debris concrete attack was considered in the Indian Point 2 IPE.

Core-Concrete Interaction (Basemat Melt-through)

The Indian Point 2 design is such that water fills the reactor cavity when the primary system contents are released. Also, the design of the sump is such that the Containment floor is also covered with water even when the RWST contents are not injected into containment. However, if the debris is not in a coolable configuration then basemat melt-through may occur at Indian Point 2. Basemat melt-through was considered in the Indian Point 2 IPE Containment analysis.

Blowdown Forces (Vessel Thrust Force)

Failure of the Containment Building as a result of gross displacement of the reactor vessel (above the shield wall) was considered in the NUREG/CR-4551 Surry accident progression analysis. However, the assigned probability for this event was sufficiently small that it made a negligible contribution to the probability of early containment failure. This mode of containment failure was not considered in the Indian Point 2 IPE Containment analysis.

Liner Melt-Through (Direct Contact of Containment Shell with Fuel Debris)

This issue is of primary concern to BWR plants because of the drywell design. This mode of failure was not considered in the Indian Point 2 IPE since the pathways for debris transport out of the reactor cavity are to interior Containment Building compartments away from the Containment wall.

Failure of Containment Building Penetrations

Failure of Containment Building penetrations (electrical, fluid, equipment hatch, personnel hatch, etc.) was evaluated in the NUREG-1150 Surry analysis and was judged to be significantly less important than over-pressure failure of the cylinder wall. Based on the NUREG-1150 results and on reported Indian Point 2 studies, this failure mode was not explicitly included in the Indian Point 2 IPE.

4.4.2 Containment Building Over-pressure Fragility

The Level 2 analysis considers the possibility of the Containment Building failing under various accident scenarios. In order to be comprehensive, failures resulting over the spectrum of possible pressures must be considered. The NUREG-1150 work characterized Containment failure using four parameters: likelihood of failure as a function of Containment pressure, failure size, location of failure and timing. Likelihood of failure is the primary parameter of interest in the study. Failure size is important because the larger the hole the faster the release of radionuclides following an accident. The location of the failure is important because the retention of radioactive materials can be dependent on this parameter. The longer the materials can be retained inside the Containment before escaping the larger the reduction in source term to the environment since the radionuclides are removed from the Containment atmosphere by natural processes and ESFs. For a similar reason timing is also important.

The results of the United Engineers (UE), which is presented in the IPPSS (Appendix 4.4.1), were that the Indian Point Units 2 and 3 containment vessels could withstand a pressure of 126 psig (141 psia), "without impairing the functional capability of the containment." It was also stated that "a confident lower bound of functional capability" was defined primarily because minimum specified material strengths were used in the analysis. Other than inducing thermal strains in the containment, temperature to at least 300°F was found to have little or not effect on capability. This value has been presented (Ref. 4.4-2) in the IPPSS hearings. Previous Sandia and Los Alamos studies indicated the possibility of lower values. The 1980 Sandia study (Ref. 4.4-3) reported results of simple hand calculations using hoop stress formulae is given as 123 psig for the pressure causing failure. It is noted in the report that minimum properties were used where in actuality they are probably higher and also that the seismic rebar was not included. A dynamic finite analysis axisymmetric model attempted as a quasi-static analysis and ignoring penetrations indicated a failure pressure of 110 psig. The 1982 study by Los Alamos (Ref 4.4-4) gave quasi-static analyses that predicted failure at the basemat-sidewall cylinder location at an internal pressure of 118 psig with a lower bound failure pressure of 112 psig and an upper bound of 133 psig.

The best available recent applicable consideration of uncertainty and failure values comes from the Expert Panel Assessment reported in NUREG-1150 for Surry (Ref. 4.4-1). The Indian Point 2 and the Surry containments are both of reinforced concrete and have the same general design. The expert panel considered them similar and referenced the UE IPPSS work heavily as a basis for Surry. They also relied on a Stone & Webster study of Surry (Ref. 4.4-5) which quoted a "minimum theoretical yield capacity" of 119 psig. Even though two of the four experts on the panel did not consider failure possible below 120 psig (a view point that could be considered analogous to the SWEC analysis statements), the other two experts did believe that there was a considerable chance of failure below such levels, giving reasons based on such things as construction quality uncertainties. The aggregrated results for Surry were given as a median failure pressure of 128 psig (with leakage as the most likely failure mode below that value.) The 5th and 95th percentiles are 95 psig and 150 psig, respectively. This assessed distribution cannot be ignored and is considered applicable to Indian Point 2 because of the plant similarities and the methodology of the panel. It should also be noted that at the ASLB hearings (Ref. 4.4-2) on IP-2, the NRC staff analysis that was presented used a distribution with a failure probability of 0.02 at 106 psig and 0.98 at 128 psig.

There is significant material available indicating that failures are possible below the point value calculated by UE for Indian Point. These are the Surry Expert Panel reasoning which appear applicable to Indian Point, the NRC staff presentations, and the lower values calculated by Sandia and Los Alamos. The existence of such failure probabilities below a calculated point value due to various uncertainties is a concept widely applied in other PRAs. The UE analysis for Indian Point 2 and the SWEC analysis for Surry used comparable methods and properties in coming up with strengths of 126 psig and 119 psig, respectively. The Surry Expert Panel arrived at a composite value of 128 psig. The differences between these three values is not deemed significant. Considering the material summarized above, a recommended value for the <u>(median) failure pressure the Indian Point 2 Containment of 126 psig is selected</u>. It attributed as the median because it is judged that there is a probability of failure below this value and that it is likely that the same type of uncertainty distribution derived for Surry would apply to Indian Point. The particular median value recommended corresponds to the UE analysis result.

Based on the same reasoning as above, the distributions for the various failure modes, and the modes themselves, developed for Surry in NUREG 1150 are considered directly applicable to Indian Point 2. The 5th and 95th percentiles for the failure pressure for Indian Point 2 are selected to be 95 psig and 150 psig, respectively. The difference in medians between 126 and 128 psig is not considered significant in applying these distributions. Leakage is assessed as the most probable mode of failure for breaches occuring up to 140 psig, while ruptures are the most likely modes of breach for failure pressures in the 140-150 psig range. A 'leak' is defined as a containment breach that would arrest a gradual pressure buildup, but would not result in containment depressurization in less than 2 hours. It is on the order of 0.1 ft^2. A 'rupture' is defined as a containment breach that would arrest a gradual buildup and would depressurize containment within 2 hours. It is a hole size in excess of approximately 1.0 ft^2.

Global failure from a hydrogen detonation will not occur and temperature effects on global failures are discounted. The Sandia analysis of a 0.03 second triangular pulse shape peaking at 250 psig caused strains on the order of 1% which was considerably below the failure strains of 22% and 7% for the liner and rebar material, respectively. The Los Alamos transient analysis indicated that the building would not fail from a pressure shock pulse applied from the detonation of a 25% hydrogen concentration ignited at the center of the dome resulting in a step overpressure of 65 psig and an additional impulse of 0.071 psi/s with a peak pressure at the wall of over 500 psig.

The expert panel who addressed the issue of containment performance at Surry relied in part on the calculations previously performed for the similar containment building of Indian Point (IPPPS, Appendix 4.4.1) and in part on the Stone & Webster (SWEC) study of the Surry Containment. The 1/6 scale model tests at Sandia (Ref 4.4-6) and other containment analyses were also used by one or more of the experts as source material.

Surry has a design pressure of 45 psig. The SWEC study concluded that the "minimum theoretical yield capacity .. is 119 psig." The study was abbreviated at the point when the reinforcement was at approximately two times yield strain. The study did not examine the behavior of the containment at the ultimate (tensile) capacity of the reinforcement. Minimum specified yield strengths were used in the analysis. No judgement of actual material, modeling, or construction uncertainty is given in the reference.

The results of the NUREG 1150 Expert Panel are summarized on NUREG/CR-4551, Figure 2-1. Expert A calculated by hand a hoop stress of 119 psig which he took to be the lowest pressure at which he would expect to find any chance of failure. Expert B placed the lowest bound at 75 psig with the bulk of the failure probability above 90 psig to account for possible construction defects such as poor cadwelds of the rebar. As with the other panel members he expects failures at low pressures to be mostly leaks due to defects, liner tears, and such. In the middle of the failure pressure range ruptures predominate, and catastrophic ruptures or burst failures only at the upper end of the range. Expert B thus placed half his probability of failure below 120 psig. He pointed out that the Surry Containment was constructed quite some time ago when construction methods and quality control were not at today's standards. Expert C was fairly confident that failure could be expected between 135 psig and 155 psig as 85% of his probability lay within that range. He referenced the Sandia tests regarding the leak mode and liner tear failures. Expert D concluded that a leak was certain to develop by 130 psig at a rebar strain of 1 per cent. He took 110 psig for his median value for leaks. 110 psig places both the liner and the hoop reinforcement at their respective yield stresses. He concluded that their was no chance of a leak developing below 75 psig. He noted that if the leak did not arrest the pressure rise, then the hole size would increase up to the rupture size.

The probability distribution over potential failure modes was derived by aggregrating the distributions of each expert for the modes. The 5th-95th percentile range extends from approximately 95 psig to 150 psig. The mean and the median pressures are around 127 psig. Leakage was assessed as the most probable mode of failure for breaches occuring up to 140 psig, while ruptures were the most likely modes of breach for failure pressures in the 140-150 psig range. A 'leak' was defined as a containment breach that would arrest a gradual pressure buildup, but would not result in containment depressurization in less than 2 hours. It is on the order of 0.1 ft^2. A 'rupture' was defined as a containment breach that would arrest a gradual buildup and would depressurize containment within 2 hours. It is a hole size in excess of approximately 1.0 ft^2.

Yielding of one of the steel hoop bars that reinforce the vertical concrete wall was identified as a likely mode of failure by all four of the experts. The location was assessed to be near the intersection of the wall with the dome. Leakage due to the formation of a tear in the steel liner was also identified as the most likely failure mode in light of the results of the 1:6 scale model reinforced concrete containment test performed at Sandia.

The NUREG-1150 characterization of the failure sizes were also utilized in this study. They are as follows:

> A leak was defined as a containment breach that would arrest a gradual pressure buildup, but would not result in containment depressurization in less than 2 hours. The typical leak size was evaluated for all plants to be of the order of 0.1 ft^2.
>
> A rupture was defined as a containment breach that would arrest a gradual pressure buildup and would depressurize the containment within 2 hours. For all plants, a rupture was evaluated to correspond to a hole size in excess of approximately 1.0 ft^2.
>
> A catastrophic rupture was defined as the loss of a substantial portion of the containment boundary with possible disruption of the Piping Systems that penetrate or are attached to the containment wall.

Global failure from a hydrogen detonation will not occur and temperature effects on global failures are discounted. The Sandia analysis of a 0.03 second triangular pulse shape peaking at 250 psig caused strains on the order of 1% which was considerably below the failure strains of 22% and 7% for the liner and rebar material, respectively. The Los Alamos transient analysis indicated that the building would not fail from a pressure shock pulse applied from the detonation of a 25% hydrogen concentration ignited at the center of the dome resulting in a step overpressure of 65 psig and an additional impulse of 0.071 psi/s with a peak pressure at the wall of over 500 psig.

4.4.3 References for Section 4.4

4.4-1 NUREG/CR-4551, Evaluation of Severe Accident Risks: Surry Unit 1, Volume 3, Revision 1, Part 1 (Main Report) and Part 2 (Appendixes), October 1990.

4.4-2 See for example in USNRC Docket 50-247-SP ASLBP Memorandum and Order dated May 31, 1983. Also USNRC Decision CL1-85-06, dated May 1985.

4.4-3 NUREG/CR-1410, Volume 1, "Report on the Zion Indian Point Study", 1980

4.4-4 NUREG/CR-2946 " Response of the Zion and Indian Point containemnt Buildings to Severe Accident Conditions" May 1982.

4.4-5 TP 84-13, "Containment Integrity at Surry Nuclear Power Stations", Stone and Webster Engineering Corp., February, 1984.

4.4-6 Letter to J.F. Costello, USNRC, from D.S. Horschell, Sandia National Laboratory, August 2, 1987.

SECTION 4.5

CONTAINMENT EVENT TREES

4.5 Containment Event Trees

A containment event tree (CET) is a logic model to delineate the possible paths that an accident sequence may progress along given an initial set of conditions defined by a plant damage state. The headings in the IP-2 CETs consist of only the important "events" which can lead to significantly different outcomes in the sequence progression where the major outcomes of interest relate to timing and mode of containment failure and the atmospheric release of radionuclides (the source terms). The events in the containment event tree generally are chosen to:

1) represent the uncertainties in physical phenomena (e.g. direct containment heating, containment loading);
2) assess operator recovery and mitigation actions,
3) assess consequential failure of important systems given the occurrence of specific physical phenomena (e.g. H_2 burns) or as a result of the general severe accident environment.

The number of headings that are required for a containment event tree to depict the important accident progression possibilities and to define the spectrum of possible outcomes need not be large. Additional event detail required for the quantification of CET events have been relegated to decomposition event trees (DETs). These quantification aids are further discussed below.

4.5.1 Containment Event Tree Development

Containment event trees have to be developed for each plant damage state. The top events in the CET consist of phenomenological events or processes and consequential systems failures resulting from physical phenomena or the accident environment which are considered to be important to the definition of the source term and the time, mode, and location of containment failure. The severe accident phenomena and containment events specified in Generic Letter 88-20 have been evaluated for inclusion in the CET. Also considered were the detailed set of events developed for NUREG-1150 and for NUREG/CR-4551 (Ref. 4.5-1). A review of past PRAs (the IPPPS inparticular) and IDCOR results was performed to identify events which should be included in the CET.

Specific events to be included in each CET were determined to a large extent by the characteristics of the sequences in each plant damage state with which a particular CET is associated. Additional events were identified based on a review of the specific design and operational characteristics of the IP-2 plant.

In the CET, events that occur nearly simultaneously and/or have effects that are interrelated are combined into single events. For example events "Direct Containment Heating" and "Mode of Early Containment Failure" were combined since they relate to, or contribute to, over-pressure loading of the containment at the time of vessel failure.

Event timing was a key factor in organizing the events on the CET. The accident progression was divided into distinct time periods for which different phenomenological processes are important and for which different recovery and mitigation actions may be effective. The general time periods considered were:

prior to RV failure
at or within a few hours of the time of RV failure
late - many hours after RV failure

A general containment event tree structure was used to assess containment accident progression for nearly all plant damage states except those PDS associated with containment bypass sequences (SGTR or ISL) and loss of isolation sequences. For these later classes of plant damage states, special CETs were developed. Although the general CET structure was the same for all PDS, the quantification of the CET was different as a result of differing PDS characteristics. The general CET structure is shown in Figure 4.5-1. The events selected for incorporation into the general CET are those judged to be the most important for assessing IP-2 containment accident progression, containment failure and source term. These events are grouped on the tree into the three principle time periods of interest for the analysis shown above. To gain insights into the accident progression and support the CET development, analyses were carried out for selected topics. The MAAP calculations referred in Section 4.7 indicate the type of calculations performed.

4.5.2 IP-2 General Containment Event Tree Events

The following discussion summarizes the events included in the general IP-2 CET.

Mode of Induced Primary System Failure

This question asks if the elevated temperatures and pressures within the Reactor Coolant System following core uncovery can result in failure of the RCS pressure boundary outside of the vessel prior to reactor vessel lower head failure. Three branch possibilities are considered:

1. no induced RCS failure
2. rupture of a hot leg (or the pressurizer surge line)
3. steam generator tube rupture w/o SORV

Induced RCS pressure boundary failure is only likely to be important for sequences where the RCS pressure remains elevated during core uncovery and core heatup, since the high pressure conditions enhance natural convection heat redistribution from the core to the hot leg and steam generators (Generic Letter 88-20, Appendix 1) and the high pressure conditions may lead to failure of these components at elevated temperatures. Each of the possible branch pathways for this event has an important impact on accident progression. Hot leg failures are likely to be of sufficient size (large break LOCA) to cause depressurization of the RCS prior to vessel failure and consequently to greatly reduce the probability that energetic events at vessel failure (e.g., DCH or H_2 burning) will cause containment failure. Failure of one or more steam generator tubes can result in a bypass of containment if a secondary relief/safety valve opens or if there is significant leakage past the MSIVs. Unless the number of induced steam generator tube failures is large (> 10), the primary system would not be expected to depressurize prior to reactor vessel failure.

Debris Cooled In-Vessel

Given that core uncovery and some core damage has occurred, this question considers whether the damaged core can be cooled in-vessel and gross damage and vessel failure prevented. For there to be any possibility that the core be cooled in-vessel, then a supply of water to the vessel in excess of that required to remove decay heat must be supplied. This requires an absolute minimum of several hundred gpm injection flow. At this minimum flow level the probability of successfully cooling the damaged core in-vessel will be low, even given a core debris configuration favorable to cooling. At substantially higher injection flow rates (several thousand gpm) the probability of cooling the debris under less favorable debris configurations (e.g. at later times with greater amounts of core damage, core slumping and/or core melting) is enhanced.

The plant damage state entry conditions defines whether low pressure (or high pressure) injection flow is (or can be) provided. The types of core damage sequences with coolant injection to the vessel following core damage initiation can be divided in two major classes. The first class of sequences are those where the injection flows are insufficient to prevent core damage as defined by the Level 1 analysis success criteria of limiting peak core temperatures to less than 2200°F (1200°C). An example of this type of sequence is a large break LOCA with successful low pressure injection but with failure of the Accumulators to inject. The second class of sequences are those where there is no coolant injection prior to core uncovery and incipient core damage but where some form of injection is recovered prior to vessel failure. This second class of sequences would include station blackout with late recovery of power and high pressure sequences with failure of high pressure injection followed by late depressurization (as a result of induced hot leg or surge line rupture) followed by successful LPI. The possible branch pathways for this event are:

1) debris cooled in-vessel (no vessel failure), and
2) debris not cooled in-vessel.

If the debris is cooled in-vessel containment failure is extremely unlikely since only limited hydrogen production would be expected, steam generation will be limited, and DCH is not a possible threat. Furthermore, radionuclide release from the debris will be limited and longer-term revaporization of radionuclides deposited on RCS surfaces will be largely avoided. Hence, because the containment does not fail and because of the limited radionuclide release, the environmental source terms for core damage sequences successfully terminated in-vessel are expected to be very small. The sequences of this type are very similar to the TMI-2 accident.

Loss of Isolation or Mode of Early Containment Failure

This question determines whether the containment fails early in time, and if containment fails, what the mode of containment failure is. Early containment failure is defined as shortly before, at, or soon after reactor vessel failure. Early containment failure can potentially result from a combination of energetic processes and events which may occur at reactor vessel breach. These processes and events include blowdown of the primary system, direct containment heating (DCH), hydrogen combustion and rapid steam generation in the cavity, and a large in-vessel steam explosion causing an alpha mode containment failure.

The ultimate containment strength for the IP-2 containment was evaluated by United Engineers and included in the Indian Point Probabilistic Study. A supplemental analysis was performed as part of this IPE to determine a containment fragility curve based on the United Engineers study and on similar studies from other plants - see section 4.4. From this study, it was concluded that the median failure pressure of the IP-2 containment is approximately 126 psig. The limiting zone for the containment was found to be below the springline in the region where the seismic reinforcing steel is reduced. Two rupture sizes were considered: a rupture and a leak. The major difference between a rupture and a leak is that a rupture is capable of arresting a gradual pressure rise in containment and in depressurizing the containment in less than 2 hours. A leak would also arrest a gradual pressure buildup but would not result in containment depressurization within 2 hours. The break areas that characterize these failure modes are as follows:

1) rupture (leak size approximately 1 ft^2 or larger)
2) leak (leak size up to 1 ft^2 with typical size 0.1 ft^2)

The IP-2 containment fragility curve 5th to 95th percentile range of potential failure pressures extends from approximately 95 psig to 150 psig. The IP-2 containment analysis estimated that if containment failure occurred below 135 psig that leakage was the most likely failure mode. Ruptures were the most likely failure mode for failure pressures above 135 psig. (Note: In the NUREG-1150 study for Surry, a catastrophic rupture failure mode was defined at the upper end of the rupture sizes. This failure can lead to mechanical (structural) disruption of containment systems. However, based on the Surry IPE evaluation, this mode was not a significant contributor to containment failures in the early time frame. Therefore, this failure mode is excluded from the IP-2 early containment failure categories.)

Furthermore, for the IP-2 CET, steam explosion induced (alpha mode) containment failures are also considered to result in a catastrophic rupture of the containment. Postulated alpha mode containment failures result from large coherent in-vessel steam explosions which fail the reactor vessel and generate a missile (from part of the reactor vessel upper head) with sufficient mass and energy to fail containment. There is a substantial body of evidence to suggest that in-vessel steam explosions do not represent a credible threat to early containment failure (i.e., the probability of early containment failure resulting from in-vessel steam explosions is negligibly small). This opinion appears to be shared by the authors of Appendix 1 to Generic Letter 88-20. However, since in-vessel steam explosions were considered in the NUREG-1150 containment analysis for Surry (NUREG/CR-4551, Ref 4.5-1) and because this event, if it should occur, can result in large and early environmental releases, this event has been included in the IP-2 IPE CET.

Experimental evidence and calculations have shown that steam explosions are much less likely at elevated pressures than at low pressure, consequently the probability of an alpha mode containment failure should be significantly less for high pressure sequences than for low pressure sequences.

It should be noted that a fast pressure rise such as from DCH or a hydrogen burn will not be arrested by a small leak. Hence, for these loading conditions, a small leak, if it occurs, may progress to a rupture.

The containment failure modes discussed above would only occur if the core melt is not arrested in-vessel and if the containment is initially isolated. If the containment is not isolated at the time of core melt, the mode of failure is similar to that of a leak type failure. If the core melt is arrested in-vessel and the containment is isolated, no containment failure is postulated.

The branches for this event are:

1. No Early Containment Failure
2. Leak
3. Rupture
4. Alpha Mode Failure
5. Isolated (and core melt arrested in-vessel)
6. Not Isolated

Containment Heat Removal or Recirculation Spray Available Early

The failure of the containment heat removal systems and the Recirculation Spray System is included on the containment event tree because these systems provide the heat removal for the containment. Hence, without the Recirculation Sprays or heat removal

(RHR or fan coolers)the pressurization of the containment will continue unabated once the heat sinks absorb all the energy possible. Also, the failure of containment heat removal early in the transient could lead to the failure of the containment systems so that the possibility of long term in-vessel or ex-vessel debris cooling would be reduced. In addition, operation of the spray system or fan coolers provide an effective mechanism for fission product mitigation. Early is defined, as in previous event headings, to be before, at, or just after vessel failure.

Initial "failure" of the Recirculation Sprays or Containment Fan Coolers is most likely to be from station blackout. Since the Recirculation Spray System is diverse (RHR pumps can backup the RS pumps) random system failures are not likely to defeat this function. Other potential failure modes that may lead to failure of the Recirculation Sprays include spray failure as a result energetic containment failure, a massive blockage of the containment sump screens by the core debris or environmental conditions inside the containment or in the Primary Auxiliary Building that result in failure of the Recirculation Spray pumps or RHR pumps. Similarly, since only three of the five containment fan cooling units are required for success, random fan failures are not likely to defeat the function. However, failure of all the fans could result from a harsh environment within the containment or by energetic events inside the containment.

The effects of local hydrogen combustion on equipment is accounted for in the quantification of the effect of the containment environment on the spray pumps and fan coolers. Because of the diversity and redundancy of these systems, local hydrogen burns is not expected to have a significant impact on the failure probability. In addition, since only the catastrophic rupture failure mode of the containment is judged capable of failing the spray nozzle headers, header failure due to hydrogen combustion effects is considered bounded by the spray motor failures.

The four branches for this heading are the combinations of containment safeguards that might be available for success of the spray function or the heat removal function. These combinations are:

1. CHR and Sprays available
2. Only Sprays are available
3. Only CHR available
4. None (Neither Sprays or Fans available)

Debris Cooled Ex-vessel

This question concerns long term containment loadings resulting from core debris concrete attack. Debris concrete attack results in concrete degradation and ablation, production of non-condensible and combustible gases, additional heat generation from chemical reactions, changes in the corium mass chemical composition and releases of radionuclides and aerosols.

If the debris is cooled then its only subsequent challenge to the containment is the continued addition of the decay heat to the cooling water and hence to containment. The presence of long term containment heat removal is thus required for success in this event.

Physically, the debris is not cooled if the debris surfaces that are exposed to the heat-removing medium are not large enough with respect to the heat generating volume to prevent high temperatures being attained. High surface-to-volume ratios imply debris being spread thinly over a large surface area. Additionally, sufficient cooling water must be present. However, if spread thinly enough, fan coolers alone might be sufficient and water may not be necessary.

For vessel breach sequences where the primary system is at low pressure, the core debris will likely remain in the cavity. Due to the keyway design in IP-2, water will collect in the cavity from sources such as the containment sprays, primary coolant inventory, or from condensation of steam. Therefore the coolability of the debris will only depend on the spread of the debris in the cavity and in the presence of long term heat removal. For high pressure vessel breach sequences a considerable fraction of the debris may be transported out of the cavity, relocating to the upper containment. Here, there is a higher degree of debris spread but the the coolability of the debris will also depend on the availability of the Recirculation Spray system for water and for long term heat removal.

The branches for this event are:

1. Debris Cooled Ex-vessel
2. Debris Not Cooled Ex-vessel

Mode of Late Containment Failure

The CET heading, mode of late containment failure, is similar to the heading for early containment failure. The obvious difference is that the accident has been in progress for a significant amount of time. The time frame for late containment failure begins many hours after the vessel has failed and continues indefinitely.

The structural analysis discussed in the section entitled mode of early containment failure is also applicable in this section. The primary cause for failure of the containment late in time would be from steam overpressurization, resulting from loss of the Recirculation Sprays or containment heat removal. The possibility of late failure due to a late hydrogen burn is also considered.

Unlike the cases for early containment failures, there is a small possibility that a sufficiently energetic event could occur that may disrupt piping systems which are attached to or penetrate the containment wall. Thus, an additional containment failure mode, the catastrophic rupture, is considered. This failure mode will be considered the likely failure mode for failure pressures in excess of 155 psig.

The branches for this event are:

1. No Late Containment Failure
2. Leak
3. Rupture
4. Catastrophic Rupture

Recirculation Sprays Available Late

The Recirculation Spray System and the other containment heat removal systems are important for preventing both core damage and containment overpressurization in the late phases of an accident. In addition, the Recirculation Sprays will reduce the magnitude of the fission product release out of the containment.

The late failure of the Recirculation Sprays may be caused by a rupture of the containment or by environmental conditions inside containment and the Primary Auxiliary Building. Harsh environmental conditions can result from high radiation, high humidity, high temperatures, or from effects of local hydrogen burns.

The two branches for this heading are simply failure or no failure. Failure includes both the spray function and the heat removal function.

Containment Failure Long Term

The long term failure of the containment can result from one of several scenarios. If the Recirculation Sprays fail late in the accident then the containment pressure will increase. If containment fan coolers and other forms of heat removal are also non-functional, the containment can fail due to gradual steam overpressurization. Pressure rise in the containment can also result from the production of combustible or non-condensible gases. The containment concrete aggregate at IP-2 is limestone, which when compared to basaltic aggregate concrete, will produce more combustible carbon monoxide or non-combustible carbon dioxide upon decomposition. The addition of combustibles or non-condensibles from core-concrete interaction can result in a late containment overpressure failure. Finally, the containment can also fail due to basemat melt-through (even if the sprays function) if the molten debris is not coolable. Note that if the containment heat removal function is not available we assume that over-pressure failure will occur and neglect basemat melt-through since the offsite consequences of basemat melt-through would be small compared to over-pressure failure. The two branches for this heading are No Late Late Containment Failure and Basemat Melt-through.

Indian Point 2 CETs

Figure 4.5-1 shows the general IP-2 containment event tree which can be used for the plant damage states that do not bypass the containment. In addition, this CET can also be used for loss of containment isolation sequences. For these sequences, the most important question is whether or not the accident progression is terminated in-vessel (i.e. whether or not the debris is cooled in-vessel). Non-isolated sequences that are not terminated in-vessel are treated as leak type failures with no mitigation from containment systems (The leak type failure is chosen because the IP-2 level 1 study shows that loss of isolation sequences involves piping with cross section areas less that 1 ft^2 and that piping with areas greater than 1 ft^2 can be screened out).

For all other containment bypass sequences (i.e., interfacing system LOCAs or steam generator tube ruptures with or without a stuck open relief valve) the general CET in Figure 4.5-1 can be simplified. For these sequences, a bridge tree (i.e. a CET with one branch) is utilized. This is discussed below.

For interfacing system LOCAs ("Event V" sequences) the question is whether there is fission product mitigation in the auxiliary building. For these sequences the most important question is whether the break location is submerged in the auxiliary building. If the break is not submerged, no fission product mitigation is assumed before release into the atmosphere. As discussed in the DET for this sequence (see AUXBLDG.DET) the design of the auxiliary building at IP-2 is such that all water will drain out of the building. Therefore, there is no mitigation for any fission product release.

For SGTR sequences it is assumed that there exists a release pathway from the secondary system directly to the environment and that the tube break location is uncovered at the time of core melt. Hence, the most important factors which impact radionuclide release have been determined and no events are evaluated on the CET. Source terms from SGTR sequences will depend on whether or not there is a SORV caused by the tube rupture event. Therefore, two separate one-event "Containment" Event trees are used, one for SGTR with SORV and the other for SGTR without SORV. Note that the SGTR events entering into these bridge trees are sequences initiated by the tube rupture itself. Sequences initiated by other events but leading to an induced SGTR are covered in the general CET shown in Figure 4.5-1. For the induced SGTR cases as for the "regular" SGTR cases, no mitigation of fission product release is modelled.

Detailed Containment Event Trees for each plant damage state are given as Figures 4.5-2 thru 4.5-32.

4.5.3 References for Section 4.5

4.5-1 NUREG/CR-4551, Evaluation of Severe Accident Risks: Surry Unit 1, Volume 3, Revision 1, Part 1 (Main Report) and Part 2 (Appendixes), October 1990.

SECTION 4.6

ACCIDENT PROGRESSION AND CET QUANTIFICATION

4.6 Accident Progression and CET Quantification

4.6.1 Methods for Containment Event Tree Quantification

The purpose of the CET quantification is to assess the relative likelihood or probability of each distinct containment end state conditional on the plant damage state associated with the CET. This is accomplished by assigning a probability (branch fraction) to each branch in the CET and propagating (combining) the probabilities for each pathway leading to a distinct containment end state.

As discussed above, the events in the CET may represent phenomenological processes, operator actions or systems failures resulting from the severe accident phenomena and conditions. These events are different in character and the quantification process must recognize these differences.

Events associated with physical phenomena generally represent uncertainties regarding the effect the phenomenological event will have on the accident progression. The probability assigned to each branch pathway for these events are the analyst's degree-of-belief, for a given set of accident conditions, that the specific event outcome will occur. These subjective probabilities represent the uncertainty as to which is the physically correct outcome.

Conversely, an event associated with an operator action is similar to the system-based events modeled in the Level 1 event trees. In this case the event branch probabilities can be taken to represent the random or stochastic nature of the event.

To aid in the quantification of a CET event it is often helpful to logically decompose the event into "sub-events" which contribute to the event. For certain events sufficient information may be available (e.g., from past studies) to allow a direct assignment of branch probabilities without further in-depth analyses. This situation may be the case for an event which has been evaluated for a similar plant under similar conditions in a recent PRA or in NUREG-1150.

However, if the CET event cannot be readily quantified by reference to past studies then more in-depth analyses is required. The analysis proceeds by identifying the sub-events (or conditions) which can influence the CET event outcome. For example, if the CET event to be quantified is "Debris Cooled Ex-Vessel" the sub-events which contribute to this event may be identified as:

What is the pressure at vessel failure?
What was the reactor vessel failure mode?
How much has the debris spread?
Where has the debris relocated to?
What is the debris depth?
What is the debris particle size?
Is there cooling water supplied to the debris?

Some of these sub-events may be conditional on the plant damage state characteristics and some may be conditional on prior CET event branch decisions. A decomposition event tree (DET) or fault tree is often useful for decomposing and evaluating CET branch probabilities.

4.6.2 Decomposition Event Trees - General Discussion

Decomposition event trees (DETs) were developed to support the IP-2 CET quantification. They are shown in Figures 4.6-1 to 4.6-9.

There are two types of branching allowed for any DET event. The first type, called a sorting event, assigns one branch the value of one and all other branches a value of zero. The sorting event branching is based on a set of rules which determine the branch pathway based on the values for key plant damage state attributes and prior event decision in the CET. A rule is indicated on the DET diagrams by a left pointing arrow (<--) under each branch in place of a split fraction (see for example Figure 4.6-1).

The rules are logic expressions which result in the assignment to a particular event branch when the logic expression is true. Once a rule segment is evaluated as "true" processing stops and no other rule segments are evaluated. An example of a simple rule is presented later in this discussion.

The rule can be evaluated using information from PDS characteristics or from prior CET branching decisions. The rule can be simple or complex, but it must be structured so at least one of the rule segments for the DET heading will be evaluated as true.

The second type of event branching in the DETs are split fractions. For these events a probability is assigned to each of the event branches by the analyst.

The sources of "data" for quantification of the split fractions includes:

A. Results of Past Studies

B. Plant Specific Calculations

C. Separate Effects Calculations

D. Engineering Assessment/Judgment

E. System Failure Rate Date

F. Human Error Rate Data

Generally data sources A/B/C/D apply to phenomenological type events and A/D/E/F apply to system/operator action types of events.

The last event in the DET is the same event heading as in the CET. Each possible branch pathway shown in the CET for this event must also exist in the DET. After the DET is quantified the endpoint probabilities for similar branches in the last event are summed and these summed probabilities are passed back into the CET as the CET branch probabilities.

The basic considerations in the construction of a DET are that: 1) the DET endpoint outcomes match the CET event being decomposed; 2) the selected sub-events can be quantified with available data or analyses, and; 3) all dependencies in the sub-events on plant damage state conditions and prior CET branch point decisions are rigorously treated.

Split Fraction Probability Assessment

After determination of the event type and deciding whether to decompose the event, the next step is to quantify each DET split fraction branch point.

As an example of this process the following discussion describes the quantification for the DET for CET Event "Debris Cooled Ex-vessel". This DET is shown in Figure 4.6-5.

The first event on the DET "RCS Pressure at Reactor Vessel Failure" is a sorting type event which assesses whether the vessel pressure at the time of vessel failure was elevated (above 200 psig) or not elevated. If the vessel pressure is elevated then debris entrainment out of the reactor cavity must be considered. This event is uniquely determined by the plant damage state characteristics and by prior event decisions in the CET. The DET branch pathway to be followed is determined by a set of rules. The rules for this event are summarized below:

IF P:RCSPRESS=LO LO;	(If the PDS attribute for "RCS pressure at vessel failure" is LO LO)
THEN LO LO;	(Then follow the LO LO branch in the DET)
IF C:PSFAIL=HOT LEG FAILURE	(If for CET event "Induced RCS Failure" the Hot Leg Failure Branch was taken)
THEN LO LO;	(Then the RCS is depressurized before vessel failure and follow the LO LO branch)
Otherwise NOT LO LO;	(Otherwise the RCS pressure is elevated above 200 psig. So follow the branch for RCS pressure > 200 psig)

The next event asks a phenomenological question - is (a majority of) the debris dispersed out of the reactor cavity? The answer is dependent on the design of the reactor cavity and the pathway out of the cavity. Prior studies indicate that debris dispersal out of the cavity is highly dependent on the vessel pressure at failure and to a lesser extent on the failure mode of the vessel. For low pressure sequences (i.e. the LO LO branch for the previous event) little or no debris would be expected to entrain out of the cavity whereas for high pressure sequences some entrainment would be likely (probability=.82).

The third heading in the DET assesses the depth of the debris. As the debris pool depth increases the probability of cooling the debris decreases. If the RCS pressure was high at vessel failure and the debris is disbursed out of the cavity then the debris would likely spread over a relatively large area in the lower containment and the debris pool would almost certainly be shallow (< 25 cm deep). For low pressure sequences the debris will remain largely contained within the cylindrical portion of the cavity (deep pool).

The fourth event in the DET "Cooling Water to Debris Ex-vessel" is a sorting event which is determined uniquely by plant damage state conditions and is evaluated using a "rule". If cooling water is being supplied to the debris ex-vessel and if long term heat removal is available, then debris cooling is possible. If water is not being supplied to the debris or if long term heat removal is failed, then the debris pool is not coolable.

Finally, the fifth event in this DET, "Debris Cooled Ex-vessel" assess the probability that the debris pool is cooled given the set of prior conditions defined by each pathway through the DET.

4.6.3 Description of IP-2 Decomposition Event Trees

The general containment event tree (CET) has eight headings, all of which are quantified using decomposition event trees (DETs). Thw section discusses each IP-2 DET and shows how the quantification is accomplished.

4.6.3.1 Mode of Induced Primary System Failure Decomposition Event Tree PSFAIL.DET - Figure 4.6-1)

Event 1: Entry from Prior CET Event (Entry CET)

One Branch

Event 2: Mode of Containment Bypass (BYPASS)

One Branch

None

Branch Probability Type: One

Currently, this event is used as a place keeper. If one general CET was used for all PDS endpoints, the PDS parameter CONBYPASS can be used to assign a branch probability to this event to separate out the Event V, SGTR, and "no containment bypass" events.

Event 3: RCS Pressure During Core Damage/ at Vessel Failure (RCSPRESS)

Four Branches

LO LO Pressure (< 200 psia)
LO HI Pressure (200 - 2000 psia)
HIGH Pressure (2000 - 2350 psia)
HI HI Pressure (> 2350 psia)

Branch Probability Type: One/Zero

Quantified Using: PDS Parameter: RCSPRESS

Event 4: Mode of Induced Primary System Failure (PSFAIL)

Three Branches

No RCS Failure

SGTR (Steam Generator Tube Rupture) without SORV

Hot Leg Failure (Surge Line Failure)

Branch Probability Type: Split Fraction

Quantified Using: NUREG/CR-4551

Case A: LO LO and LO HI Pressure Sequences (< 2000 psia)

NUREG-1150 In-vessel Expert's Panel did not consider temperature induced SGTR or hot-leg failure to be credible events for sequences with pressures below about 2000 psi (Ref 4.6-1, Appendix A, Page A.1.1-24 and 25)

	Point Est.
No RCS Failure	1.
Hot Leg Failure	0.
SGTR	0.

Note: Only the "No RCS Failure" Branch is shown on the DET for LO LO and LO HI sequences

Case B: HI HI Pressure Sequences (> 2350 psia)

For very high RCS pressures (equal to or greater than the pressurizer PORV setpoint pressure - 2350 psig) the NUREG-1150 In-vessel Expert's Panel estimated that temperature induced SGTR would be highly unlikely if there were no defective tubes in the SGs. Since there are likely to be a number of defective tubes, however the probability of temperature induced SGTR would be increased. The expert panel estimated that under these conditions induced SGTRs would still be very unlikely [probability = .018]. However, they also estimated that hot leg or surge line failure would be likely [probability = .72]. If we make the simplifying assumption that induced SGTR and hot leg failure are mutually exclusive, then the branch probabilities shown below can be calculated. (Ref. 4.6-1, Appendix A, Page A.1.1-24 and 25)

	Point Est.
No RCS Failure	.262
Hot Leg Failure	.72
SGTR	.018

Case C: HIGH Pressure Sequences (< 2350 and > 2000 psia)

For high pressure sequences (RCS pressure less than pressurizer PORV setpoint pressure - 2350 psig and above 2000 psig) the NUREG-1150 In-vessel Expert's Panel estimated that temperature induced hot leg or surge line failure would be unlikely [probability = .034]. The panel also estimated that temperature induced SGTRs were not credible at pressures below the pressurizer PORV setpoint pressure [prob. = 0.]. (Ref 4.6-1, Appendix A, Page A.1.1-24 and 25)

	Point Est.
No RCS Failure	.966
Hot Leg Failure	.034
SGTR	.0

Note: For induced SGTR sequences, no SORV is assumed because for these sequences to occur, the primary system temperature has to be very high implying the absence of water or steam. Since the primary cause of SORV's is the passing of water or steam through the relief valves, no SORV is assumed for these high temperature sequences.

4.6.3.2 Debris Cooled In-vessel Decomposition Event Tree (INVCOOL.DET - Figure 4.6-2)

Event 1: Entry from Prior CET Event (Mode of Induced Primary System Failure)

One Branch

Event 2: Status of In-vessel Injection (INVESSINJ)

Four Branches

On
Deadheaded
Recovered
Failed

Branch Probability Type: One/Zero

Quantified Using: PDS Parameter: INVESSINJ

Event 3: Mode of Induced Primary System Failure (RCSFAIL)

Two Branches

Hot Leg Failure
No RCS Failure

Branch Probability Type: One/Zero

Quantified Using: CET Event: PSFAIL

For cases where high or low pressure injection is available but the primary system pressure is elevated above the shutoff head of the HPI system (Deadheaded) initiation of injection can occur if the RCS pressure is reduced to below the shutoff head of the pumps. Induced hot leg or surge line failure will result in a large break in the RCS which will rapidly reduce the RCS pressure to below 200 psig allowing for high and low pressure injection. Rupture of one or two steam generator tubes late in time would not be expected to depressurize the RCS to below the LPI shutoff pressure. It is also unlikely to depressurize the RCS to below the HPI shutoff pressure. Therefore, if the induced failure is in the form of a SGTR, no RCS failure is assumed.

Event 4: Debris Cooled In-vessel (INVCOOL)

Two Branches

Not Cooled
Cooled

Branch Probability Type: Split Fraction

Quantified Using: NUREG-1150,NUREG/CR-4551

Case A: In-vessel Injection On

The success criteria for large break LOCA sequences require the Low Pressure Injection system and the Accumulators to operate to avoid core damage. Similarly for intermediate LOCAs, both high and low pressure injection systems must operate to prevent core damage. For both the above cases, core damage is assumed if only the LPIS is available. However, in these cases there is a potential for cooling the core through the LPIS and the probability for preventing gross core damage and vessel failure is significant. NUREG/CR-4551, estimated that for these cases successful in-vessel cooling is likely [probability = .95]. (Ref. 4.6-1, Appendix A, Page A.1.1-32 and A1.1-33)

	Point Est.
Cooled	.95
Not Cooled	.05

Case B: In-vessel Injection Available (but RCS pressure above HPI and LPI shutoff)

If the RCS pressure remains above the shutoff head of the HPIS and LPIS during the transient, these systems may be available but not able to inject. Later in the transient an induced hot leg (or surge line) failure may cause the pressure to decrease low enough to allow injection. Successful initiation of injection may provide enough core cooling to prevent vessel failure. NUREG/CR 4551 estimated that successful in-vessel cooling is less probable for this case than for cases where injection is available early. [probability = .9]. (Ref. 4.6-1, Appendix A, Page A.1.1-33)

	Point Est.
Cooled	.9
Not Cooled	.1

Case C: AC Power Recovery After Core Damage

For loss of AC power sequences the potential exists for recovery of AC power prior to reactor vessel failure. If power is restored in sufficient time then recovery of vessel injection, and in-vessel debris cooling and prevention of reactor vessel failure is possible. Since the Level 1 PDS event tree analysis considered power recovery in the time period prior to core uncovery, the recovery period considered here is from the end of the power recovery period considered in the Level 1 analysis up to vessel failure. The level 1 analysis has determined that the time between core melt and vessel failure is approximately two hours.

For the recovery cases considered (Ref 4.6-1) the mean values for the probability of successful in-vessel cooling ranged from indeterminant to likely [.5 < probability ≤ .9]. This range accounts for the different initiators and the different entry conditions. A value midway between these two values has been selected for our point estimate value. [probability = .7] (Ref. 4.6-1, Appendix A, Pages A.1.1-32-A1.1-34).

	Point Est.
Cooled	.7
Not Cooled	.3

Case D: In-vessel Injection Failed

For the case where coolant injection to the vessel is lost and not recovered prior to vessel failure then vessel failure is certain. (Ref. 4.6-1, Appendix A, Pages A.1.1-32 - A1.1-34)

	Point Est.
Cooled	0.
Not Cooled	1.

4.6.3.3 Loss of Isolation or Mode of Early Containment Failure Decomposition Event Tree (CF-EARLY.DET - Figure 4.6-3)

A rise in containment pressure may result from several sources: blowdown of the RCS steam and hydrogen inventory; combustion of the hydrogen released prior to and during vessel failure; interactions between molten core debris and water on the containment floor; and direct containment heating. To calculate the containment pressure rise at vessel breach, each of these contributors can be accounted for individually. However, because a substantial amount of uncertainty remains (especially for the DCH and hydrogen burn issues) and because the DCH phenomenon continues to generate a great deal of controversy, containment pressure rise at vessel breach was treated as a single issue in NUREG-1150 (see Appendix C, section C.5). This single event was modelled to represent the combined uncertainties associated with the synergism of the four events listed above. As a result, the pressure increment attributable to an isolated phenomenon (e.g. DCH) is not separable. For lack of better data elsewhere in the industry, this "lumping" of the issues associated with early containment failure is also adopted for the IP-2 study.

The total energy release, and thus the pressure rise, from the above phenomena depends on the fraction of core participating in the process, the RV pressure prior to vessel breach, the initial size of the hole in the RV lower head when breached, the availability of water in the cavity, and the operability of the containment sprays during melt ejection. This breakdown is based in large part on sensitivity studies performed with the CONTAIN code (Ref 4.6-2). In this study a five "cell" CONTAIN model of the containment was utilized to assess the peak pressure following reactor vessel failure for a matrix of variations in parameters considered to be important to the calculated DCH pressure. (In addition to the parameters identified above as being important to DCH pressures, the results from this study indicated that peak containment pressure was not greatly sensitive to debris particle size, chemical reaction rate in the debris particle, extent of in-vessel Zr oxidation, or gas-structure heat transfer rates.)

Of the parameters identified above that influence containment loading, the fraction of debris participating in the DCH event, the RCS pressure before RV breach, and the operability of containment sprays are explicitly included in this DET as events 8, 5, and 7 respectively. The extent and timing of co-entrained water has not been considered in the tree for the following reason. Based on detailed evaluation of the IP-2 design for all accident sequences considered, water will collect in the the cavity due to the keyway design from sources such as containment sprays, primary coolant inventory from breaks or open relief valves, or from condensation of steam. As a result, the presence of cavity water is assigned a probability of 1.0 (IPPSS, page 2.5-6). The CONTAIN sensitivity study shows minimum values for the peak containment pressure for cases with a large mass of water co-dispersed with the debris. Consequently, the mass of co-dispersed water was not explicitly included as an uncertainty event in the tree. The initial size of the hole in the vessel when breached was also shown to have a significant impact on the peak containment pressure because it effects the rate at which vessel blowdown occurs. This parameter was not explicitly included in the tree since a very rapid blowdown (approximately 10 seconds or less) was required to significantly increase the predicted peak containment pressure. This rapid of a blowdown was judged to be very unlikely with the expected mode of vessel failure (i.e. limited area failure of a lower head penetration).

Event 1: Entry from Prior CET Event (Debris Cooled In-vessel)

One Branch

Event 2: Debris Cooled In-Vessel (INVCOOL)

Two Branches

Not Cooled
Cooled

Branch Probability Type: One/Zero

Quantified Using: CET Event: INVCOOL

If injection is available to cool the debris in the vessel, core melt might be arrested in-vessel. If core melt is arrested in-vessel, then the only question is whether the containment is isolated.

Event 3: Containment Isolation Status at Core Melt (CONTISOL)

Two Branches

Isolated
Not Isolated

Since containment isolation failure is not strongly dependent on the other systems considered in the PDS event trees, it was decided that this failure could be evaluated independently from the PDS trees. The probability of containment isolation failure for all PDS sequences will be assigned a constant value of 4.68×10^{-4} (rounded up to 0.0005). This value was calculated by the Level I analysis and is based on the failure of two isolation air-operated valves in series. There are eight pipes of concern, and each of these pipes have a cross section area of less than 1 square foot. Isolation failure from pipes greater than 1 square foot were screened out by the Level I analysis.

Branch Probability Type: Split Fraction

	Point Est.
Isolated	.9995
Not Isolated	.0005

Event 4: Containment Pressure at Reactor Vessel Failure (CONPRESRV)

Three Branches

Low	(nominal value 15 psia - range 10 - 20)
Inter	(nominal value 28 psia - range 21 - 32)
High	(nominal value 37 psia - range 33 - 42)

The three pressure ranges listed above cover the expected pressure regimes for the spectrum of IP-2 accident sequences. The low pressure regime represents all sequences with successful operation of the containment heat removal. The high pressure regime represents large break LOCA sequences and sequences where the RCS is depressurized at the time of vessel failure by an induced primary system failure and that are without containment heat removal. The intermediate regime is typical of all other sequence types where the RCS is not ruptured into the containment and depressurized prior to vessel failure and where containment heat removal is not available.

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: TRANLOCA, CNHEATREM, RECSPRAYS, POWRECOV

CET Events: PSFAIL

Event 5: RCS Pressure During Core Damage/At Vessel Failure (RCSPRESS)

Three Branches

Low (< 200 psia)
Medium (200 - 2000 psia)
High (> 2000 psia)

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: RCSPRESS

Note: The Low branch includes the PDS LO LO category; the Medium branch includes the PDS LO HI category; and the High branch includes the PDS HIGH and HI HI categories.

Event 6: Alpha Mode Containment Failure (ALPHA)

Two Branches

No Alpha CF
Alpha CF

Branch Probability Type: Split Fraction

Quantified Using: NUREG 1150-NUREG/CR-4551

Case A: Low Pressure Sequences (< 200 psig)

Steam explosions have been observed to occur much more readily at low pressures than at elevated pressures. The mean value of the aggregate distribution developed from the distributions in the Steam Explosion Review Group (SERG) (NUREG-1116) and reported in NUREG-4551 for Alpha mode containment failure is .008. (Ref. 4.6-1 Appendix A, Page A.1.1-43). This mean is unusually high and is the result of the high frequency (on the order of 10^{-2}) proposed by one of the experts. It should be noted that the majority of experts feel that the probability for an alpha mode containment failure is in the range of 10^{-4}. This opinion is shared by the NUREG-0850 review of IPPSS which concluded that the alpha mode failure probability is a hundred times smaller than that in WASH-1400, i.e. $< 10^{-4}$. The median value for the aggregate SERG distribution is 4×10^{-5} (NUREG-1150, Appendix C, Page C-88).

In this study the median value of 4×10^{-5} is used. Since there is a wide range of opinions within the technical community on this issue, sensitivity studies will be performed to evaluate the effects of this probability on source terms.

	Point Est.
No Alpha CF	.99996
Alpha CF	.00004

Case B: Medium and High Pressure Sequences (> 200 psig)

For high RCS pressure sequences the SERG distributions were decreased by one order of magnitude in NUREG-4551. This results in a median value for the Alpha mode containment failure distribution of .000004. (NUREG-1150, Appendix C, Page C-88)

	Point Est.
No Alpha CF	.999996
Alpha CF	.000004

Event 7: Containment Recirculation Sprays Available Initially (RECSPRAYS)

Two Branches

Yes
No

This event assesses whether or not Recirculation Sprays are available at the time of vessel failure.

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: RECSPRAYS, TRANLOCA and POWRECOV

Event 8: Fraction of Core Mass Involved in DCH (DCH-MFCI)

Four Branches

High	(nominal value 50% - range 40 - 60%)
Medium	(nominal value 30% - range 20 - 40%)
Low	(nominal value 10% - range 0 - 20%)
None	

The amount of core material ejected from the vessel depends on the fraction of the core that has melted and collected at the bottom of the reactor vessel at the time of vessel breach. Three discretized levels have been selected to represent the uncertainty in the amount of core debris expelled at the time of vessel failure. These levels are the same as those chosen in NUREG-1150.

Results of RELAP/SCDAP calculations performed by INEL were presented at an ACRS Severe Accident Subcommittee meeting (Ref. 4.6-3). These calculations were performed to address the question (posed by ACRS member Shewman) as to what was the expected mass of debris from the vessel likely to be available to participate in a DCH event. The RELAP/SCDAP analysis indicated that 17% would be a conservative estimate of the amount of the core debris which would be present as liquid in the lower head of the vessel and available to participate in DCH events at vessel failure. This analysis also suggested that 30% would be an upper limit on this parameter.

The fraction of core mass ejected is also a part of the NUREG-1150 expert opinion elicitation on In-Vessel Issues (Ref. 4.6-4). The range of the fractions of core material ejected was broad with a maximum fraction of about 0.6. The median value of the aggregate distribution from In-Vessel Experts Panel is .28 (Ref. 4.6-1 Appendix A, page A.1.1-42). Given the fraction of core debris released from the vessel at breach, the amount of core mass available for DCH will depend on the fraction of debris entrained out of the cavity. This in turn is dependent on the mode of reactor vessel failure. The failure of the bottom head in PWRs was a topic that was covered as part of the expert elicitation on In-vessel issues in NUREG/CR-4551. If the vessel were to fail, the experts felt that a High Pressure Melt Ejection (HPME) type failure would be probable for sequences where core melt is initiated while the primary system is at high pressure (>200 psi). For sequences where the RCS is at lower pressures, the pour failure mode becomes more dominant. Here, the lower vessel head fails and the core debris pours out into the cavity under the force of gravity. One of the experts thought a gross bottom head failure mode was also possible. This mode could occur at any primary system pressure. Here, a large portion of the bottom head falls into the cavity due to a circumferential failure or some other failure. Bottom head failures at high pressure have effects similar to a high pressure melt ejection; bottom head failures at low pressure have effects similar to a pour failure. (Ref 4.6-1, Appendix A, Page A.1.1-44 and -45). For the IP-2 study it is therefore assumed that for all high pressure sequences (>200 psig), the vessel failure mode is either by HPME or by high pressure dump (bottom head failure). For sequences below 200 psig, the pour type failure is assumed.

Since the IP-2 cavity design includes an inclined tunnel for the instrument tubes and a man-way that leads directly to the SG compartment, the debris entrainment out of the reactor cavity for high pressure sequences is likely to be large leading to close to 100% entrainment from the cavity.

Given the discussion above, it can be approximated that, for accident sequences where the RCS pressure was greater than 200 psig at vessel breach, the fraction of core inventory of debris participating in a DCH event will be in the 25% range, and that it is likely that the value would be less than 50%. Therefore, a probability of 0.5 has been assigned to the 30% branch (to reflect NUREG-1150 estimate). To account for more recent calculations (Ref 4.6-3), the 10% branch was assigned a probability of .45 with the remaining fraction of .05 assigned to the 50% branch. For lower pressure sequences, the core debris would accumulate at the floor of the reactor cavity and entrainment out of the cavity would be minimal (IPPSS, Section 3.2.8).

Branch Probability Type: Split Fraction

Case 1 - High pressure sequences (>200 psig)

		Point Est.
High	(50%)	.05
Medium	(30%)	.5
Low	(10%)	.45
None		0.

Case 2 - Low pressure sequences (<200 psig)

		Point Est.
High	(50%)	0.
Medium	(30%)	0.
Low	(10%)	0.
None		1.

Event 9: Summary Event - Total Containment Pressure for DET Path (TOTPRESS)

One Branch

Total Containment Pressure

Branch Probability Type: Summary Event - No Branching

This event is used to summarize the expected containment pressure for each DET event sequence. The pressure evaluated for each pathway is then used to evaluate the probability of containment failure and the mode of containment failure in the next event. The peak containment pressures for each pathway are summarized on Table 4.6-2 and are based largely on the aggregate results of the NUREG-1150 expert elicitation on pressure increment in the Zion containment at vessel breach (NUREG/CR-4551). A tabulation of the expert panel's assessment is summarized on Table 4.6-1. Although the above pressures are for Zion, the should also be applicable for IP-2 since the Zion and IP-2 containment designs are similar. According to the MAAP inputs for both units, the upper containment volume for Zion and IP-2 are essentially the same (2.15 million cubic feet for IP-2 versus 2.08 million cubic feet for Zion). The thermal power for IP-2 is 3071 MW compared to 3236 MW for Zion. Since the IP-2 power is approximately 5 percent smaller, the pressure increase will be expected to be approximately 5 percent less. However, due to the uncertainties, Zion results will be used uncorrected.

Event 10: Loss of Isolation or Mode of Early Containment Failure (CF-EARLY)

Five Branches

No Early CF
Leak
Rupture
Isolated
Not Isolated

The characteristics of each of these failure modes is discussed in section 4.4. As discussed in section 4.4, the containment fragility curve for IP-2 can be approximated by that developed by the NUREG-1150 experts' panel for the Surry containment. A discretized representation for this composite aggregate fragility curve was taken from the User Function for the EVNTRE code for Surry in NUREG/CR-4551 (Ref. 4.6-1) and a table of discretized failure probabilities vs containment pressure was developed (Table 4.6-3). This table was used to evaluate the probability of containment failure for each DET pathway. The mode of containment failure was assessed as follows. It was judged that 1) a Leak type failure was most likely for failure pressures less than 135 psig (150 psia), and 2) a Rupture type failure was most likely for failure pressures greater than 135 psig (150 psia). Note that in the analysis of early containment failure we assume that the peak calculated containment pressure represents the containment failure pressure. We assume that containment failures which may occur at pressures lower than the calculated peak pressure do not limit the peak pressure. Furthermore we assume that the containment failure mode is solely determined by the peak pressure regardless of which pressure containment failure first occurs at. This implies, for example, that if a Leak type failure were to occur at a lower pressure it could evolve into a Rupture if the containment pressure rises sufficiently to enter the Rupture pressure regime. The conditional probabilities for each mode of containment failure as a function of pressure are also shown on Table 4.6-3.

The probability of failure by each failure mode for each calculated peak containment pressure in the DET is evaluated by first assessing the probability of containment failure from the fragility curve and then multiplying by the conditional probability of failure for each mode (Table 4.6-3).

Note: In the NUREG/CR-4551 study for Surry, a catastrophic rupture failure mode was defined at the upper end of the rupture sizes. This failure was judged to be likely if containment pressures exceeded 155 psig (170 psia) and can lead to mechanical (structural) disruption of containment systems. However, as can be seen from the containment pressures presented in Event 9 of this DET, this mode is not a contributor to containment failures in the early time frame and thus have been excluded from the IP-2 early containment failure categories. However, in the late time frame, this failure mode becomes more important, thus, the CF-LATE DET includes the catastrophic rupture failure mode. The conditional probabilities for a catastrophic rupture is included in Table 4.6-3.

The containment failure modes discussed above would only occur if the core melt is not arrested in-vessel and if the containment is initially isolated. If the containment is not isolated at the time of core melt, the mode of failure is similar to that of a leak type failure with no credit taken for mitigation by containment systems. If the core melt is arrested in-vessel and the containment is isolated, no containment failure is postulated.

Branch Probability Type: Split Fraction

4.6.3.4 Containment Heat Removal or Recirculation Spray Available Early Decomposition Event Tree (HR-EARLY.DET - Figure 4.6-4)

Event 1: Entry from Prior CET Event (Loss of Isolation or Mode of Early Containment Failure)

One Branch

Event 2: Containment Isolation Status (ISOLATION)

Two Branches

Isolated
Not Isolated

This event assesses whether or not the containment is isolated at the time of reactor vessel failure.

Branch Probability Type: One/Zero

Quantified Using: CET Event: CF-EARLY

Event 3: Containment Recirculation Sprays Available Initially (RECSPRAYS)

Two Branches

Yes
No

This event assesses whether or not Recirculation Sprays were available (not failed mechanically and AC power is available) prior to reactor vessel failure.

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: RECSPRAYS, TRANLOCA and POWRECOV

Event 4: Containment Heat Removal Available Initially (CNHEATREM)

Two Branches

Yes
No

This event assesses whether or not sufficient containment heat removal (operation of the RHR system in recirculation or the fan coolers with functional heat exchangers) is available. This implies that the systems are not failed mechanically and AC power is available prior to reactor vessel failure.

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: CNHEATREM, TRANLOCA and POWRECOV

Event 5: Mode of Early Containment Failure (CF-EARLY)

Three Branches

No - Early CF (No Early Containment Failure)
Leak - Not Isolated
Rupture

Branch Probability Type: One/Zero

Quantified Using: CET Event: CF-EARLY

Note: The Alpha mode containment failure is not a branchpoint in this event because it was assumed that steam explosions that are sufficiently energetic to fail both the reactor vessel and containment will also fail the containment fan coolers, the recirculation spray pumps and the spray piping and headers. Therefore, it will be assumed that the Alpha mode containment failure would fail all sprays and any other containment heat removal systems.

Event 6: RCS Pressure at Vessel Breach (RCSPRESS)

Two Branches

LO LO Pressure (≤ 200 psig)
Not LO LO Pressure (> 200 psig)

Note: Not LO LO includes PDS RCSPRESS attributes:
LO HI, HIGH and HI HI. LO LO RCS pressure also results from an induced hot leg rupture. CET event PSFAIL = HOT LEG FAILURE.

Branch Probability Type: One/Zero

Quantified Using: PDS Parameter: RCSPRESS, and
CET Event: PSFAIL

Event 7: Containment Heat Removal or Recirculation Spray Available Early (HR-EARLY)

Four Branches

CHR and Sprays Available
Only Sprays Available
Only CHR Available
None

Branch Probability Type: Split Fraction

Quantified Using: Engineering Analysis/Judgement

This event determines the status of the containment sprays and containment heat removal. Even if the sprays and containment heat removal were functioning initially, certain situations could arise to fail these functions. These situations include: (I) an early containment failure directly causing spray and/or FCU failure; (II) excessive debris in the sumps causing spray pump failure; (III) a failure of the spray pump motors and/or fan cooler units due to harsh environmental conditions; or (IV) excessive debris in the upper containment causing FCU failure. Since success of the spray function is dependent on either the Recirculation Spray pump motors (located inside the containment) or the RHR pump motors (located in the Primary Auxiliary building), item (3) above will only fail the spray function if environmental conditions in both the containment and in the PAB are unacceptable. This implies that the containment will have to fail into the PAB. Each one of the above items is discussed individually below.

I) Containment Failure Directly Causes Spray or FCU Failure

The Sandia structural engineers who were consulted by the NUREG/CR-4551 authors indicated that the probability of spray failure as a result of containment failure was "incredible" for all Surry containment failure modes except catastrophic rupture. For the case of catastrophic rupture they indicated that spray failure was unlikely with a probability of 0.1 (Ref 4.6-1, Appendix A, Page A.1.1-56). Since IP-2 has only two trains of containment sprays compared with four for Surry the probability of failing the spray function at IP-2 due to a catastrophic rupture should be greater than that assumed for Surry. However, the presence of FCU's at IP-2 provides for a more diverse heat removal capability. Therefore, for IP-2 the probability of failure of ESFs contained within or penetrating the containment pressure boundary is judged to be the same as that for Surry. For catastrophic ruptures this failure probability is 0.1. (However, as discussed in the CF-EARLY DET, the catastrophic rupture failure mode is insignificant at IP-2 in the early time frame.) For rupture failure modes, the probability of failure of both the recirculation sprays and FCU's is assumed to be an order of magnitude smaller than that for catastrophic ruptures, or 0.01. For leak type failures, the probability of ESF failures is assumed to be negligible (probability = 0) because these failures would not involve such a large portion of the containment structure that both spray trains and three of the five FCU's would be severely damaged.

Case A: No Early CF

	Point Est.
No Failure	1.
Spray/FCU Failure	0.

Case B: Leak Type Failures

	Point Est.
No Failure	1.
Spray/FCU Failure	0.

Case C: Rupture Type Failures

	Point Est.
No Failure	.99
Spray/FCU Failure	.01

II) Excessive Debris Causes Spray and FCU Failure

Two failure mechanisms are postulated which could result in Recirculation Spray pump failure - (1) large core debris particles collecting on the fine mesh screens in the sumps and blocking flow to the pumps and (2) passage of smaller debris particles through the fine mesh screens and into the pump suction which could damage the pumps. In IP-2, the water inventory for Recirculation Spray is from the recirculation sump (via the recirculation pumps) and from the containment sump (via the RHR pumps). 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 (screen mesh size is 0.25 inch) and to reduce water velocity to minimize debris carryover. The containment sump is located relatively close to the incore instrument tunnel cavity exit which is the most likely pathway of debris being entrained from the cavity. Hence debris that is expelled from the cavity will not need to be transported too far to reach the containment sump. The recirculation sump is somewhat further away and is located approximately a quarter way around the containment. Therefore it is unlikely that sufficient amounts of core debris will be entrained from the cavity and transported across containment to block the recirculation sump or damage the Recirculation Spray pumps. However entrained debris from the cavity would likely find its way to the containment sump and is assumed to eventually fail the spray function from the RHR pumps.

The effect of excessive debris on the FCU's is not as well defined. Large debris particles could directly damage the fan units or fail the fan motors. However, the FCU's are well spaced throughout the containment and it is unlikely that more than three of the five units will be failed by debris in the containment.

Case A: LO LO RCS Pressure at Vessel Failure

For sequences with RCS pressure < 200 psig at vessel failure little debris would be expected to be entrained out of the reactor cavity. Therefore, no failure of the fans or sprays is expected.

	Point Est.
No Failure	1.
Spray/FCU Failure	0.

Case B: Not LO LO RCS Pressure at Vessel Failure

For sequences with RCS pressure > 200 psig at vessel failure extensive debris entrainment out of the reactor cavity would be expected and there exists the possibility for sufficient amounts of core debris to be transported to the containment sump to potentially cause RHR pump failure. However, failure of the Recirculation pumps is judged to be unlikely. In addition, the FCU's are spatially separated and it is unlikely that three of the five units will fail from debris in the containment.

	Point Est.
No Failure	.9
Spray/FCU Failure	.1

III)Environmental Conditions in Containment fail Recirculation Spray Pump Motors and Containment Fans

This determines whether the environmental conditions (temperature, pressure, humidity, radiation) in the containment early in the accident sequence will cause failure of the Recirculation Spray pumps and the Containment Fan Coolers. Both the Recirculation Spray pumps and the Fan Coolers are qualified for the severe accident environment from a LOCA. Over-pressure failure of containment implies that the temperature of the containment atmosphere was elevated to a minimum of 350 °F and possibly much higher if the containment atmosphere was superheated (for example by a DCH event or hydrogen combustion event). These early pressure transients arising from vessel blowdown, DCH, hydrogen burns etc. are likely to be short lived as containment heat sinks, spray systems and fan coolers act to cool the containment atmosphere. Therefore, it is reasonable to assume that the sealed Recirculation Spray pump motors and fan coolers can withstand transient ambient temperatures well in excess of their peak qualification temperature for a short period of time. Consequently, it is believed that the failure of the RS pumps and fan coolers will be very unlikely (failure probability = 0.01) due to environmental conditions for pressure transients which do not result in containment failure and unlikely (failure probability = 0.1) for transients which result in containment failure.

Because of the diversity and redundancy in the spray and fan cooler systems, local hydrogen burns is not expected to fail the spray or containment heat removal functions. Therefore, hydrogen combustion effects are considered bounded by the other environmental conditions discussed above and will not be treated explicitly.

Case A: No Containment Failure

	Point Est.
Yes (RS & Fans Fails)	.01
No (No RS & Fan Failure)	.99

Case B: Leak or Rupture Mode Containment Failure

	Point Est.
Yes (RS & Fans Fails)	.1
No (No RS & Fan Failure)	.9

IV) Containment Fails into Primary Auxiliary Building

The Primary Auxiliary Building is adjacent to the containment wall and houses the RHR pumps. Containment failure into this building may result in environmental conditions which could ultimately fail the RHR pumps, heat exchangers, valves, or power supplies. The contact with the containment wall extends from the basemat of the containment (top of basemat at elevation 46') to elevation 80'. It also covers an arc of the containment wall of 59° with a length of approximately 75.7'. Hence, the auxiliary building covers an area of:

$$A_{PAB} = 75.7 \times (80 - 46) = 2574 \text{ ft}^2$$

Containment geometric data:

cylinder outside radius = 73.5'
cylinder height = 148' (from basemat to bottom of springline)
dome outside radius = 71' (67.5' ID plus 3.5' wall thickness)

The containment cylindrical wall has an outside surface area of:

A_{cyl} = 148 x 2 x pi x 73.5 = 68300 ft^2

The containment dome has an outside surface area of:

A_{dome} = 2 x pi x $(71)^2$ = 31700 ft^2

The total containment outside surface area is then:

A_{cont} = 68300 + 31700 = 100,000 ft^2

Assuming that the probability that the containment will fail in any given area of the containment wall is uniform within the cylindrical wall and dome, then:

$$P_{CF-PAB} = \frac{2754}{100,000} = .026$$

Note: In their study of the IP-2 containment strength, United Engineers indicates that the dominant failure location is just below the springline inn the region where the seismic reinforcing steel is reduced. This location would be above the top of the primary auxiliary building. If the probability of failure at a specific location is not uniform across the entire containment surface as has been assumed in the above analysis but is dominated by failure at the dome - cylinder interface then the probability of containment failure into the region of the auxiliary building would be reduced.

	Point Est.
No (No failure into PAB)	.974
Yes (Failure into PAB)	.026

V) Environmental Conditions in the Primary Auxiliary Building Fails RHR Pump Motors

Given that the containment has failed into the Primary Auxiliary Building (and given that the RHR pumps are not already failed by debris in the containment sump, i.e. sequences where RCS pressures are less than 200 psig) this question assesses whether the environmental conditions (temperature, pressure, humidity, radiation) in the auxiliary building will cause failure of the RHR pump motors.

The considerable size of the auxiliary building and the numerous compartments within it would act as heat sink as well as present a physical barrier which would mitigate the effects of containment failure into the auxiliary building. In addition, the ESF pump rooms in the auxiliary building are environmentally qualified for a postulated LOCA. Therefore, except for the containment rupture failure mode, RHR pump failure is unlikely.

Case A: No Containment Failure

	Point Est.
Yes (RHR Fails)	0.
No (No RHR Failure)	1.

Case B: Leak Type Containment Failure

A leak type failure is characterized by a failure size of approximately 0.1 ft^2 (4 in diameter hole). This is the failure mode considered most likely for containment failure at pressures below 135 psig. Because of the limited leak rate from containment it is judged to be unlikely that the RHR pump motors will fail.

	Point Est.
Yes (RHR Fails)	.1
No (No RHR Failure)	.9

Case C: Rupture Type Containment Failure

A rupture type failure is characterized by a failure size of approximately 1.0 ft^2 (14 in diameter hole). Because of the much larger leak rates from the containment and uncertainties as to the actual peak temperatures the RHR pump motors can withstand it is judged that failure of the RHR pump motors is indeterminant.

	Point Est.
Yes (RHR Fails)	.5
No (No RHR Failure)	.5

VI) Summary

Theoretically, each of the above items (I through V) can be made into individual events in this DET thereby making the calculation of the DET endpoints simple. However, because of the large uncertainties in each of the above parameters, it was decided that a single value be assigned to represent this event. The split fraction probabilities for this event is calculated below based on the discussion in items I through V.

Case A: No Early CF; LO LO RCS Pressure

Entry Conditions (Mode of CF/ RCS Pressure)	CF Causes RS & CF Failure	Debris Causes RS & CF Failure	Cont Fails Into PAB	Envir In PAB Fails RHR Pumps	Envir Inside Cont Fails FCUs & RS Pumps	Status	
No early CF Lo Lo	No	No	No	No	No .99	CHR & SPRAYS	.99
					Yes .01	CHR & SPRAYS	.01

For this case, even if the FCU's and RS pumps are failed from environmental conditions inside the containment, RHR pumps is available for CHR and the spray functions.

Summary for Case A:

	Initial Availability		
	CHR & RS	RS only	CHR only
CHR & SPRAYS	1.0	-	-
SPRAYS ONLY	-	1.0	-
CHR ONLY	-	-	1.0
NONE	-	-	-

Case B: No Early CF; Not LO LO RCS Pressure

Entry Conditions (Mode of CF/ RCS Pressure)	CF Causes RS & CF Failure	Debris Causes RS & CF Failure	Cont Fails Into PAB	Envir In PAB Fails RHR Pumps	Envir Inside Cont Fails FCUs & RS Pumps	Status	
No early CF Not Lo Lo	No	No .99	No	No	n/a	CHR & SPRAYS	.99
		Yes .01	No	No	n/a	NONE	.01

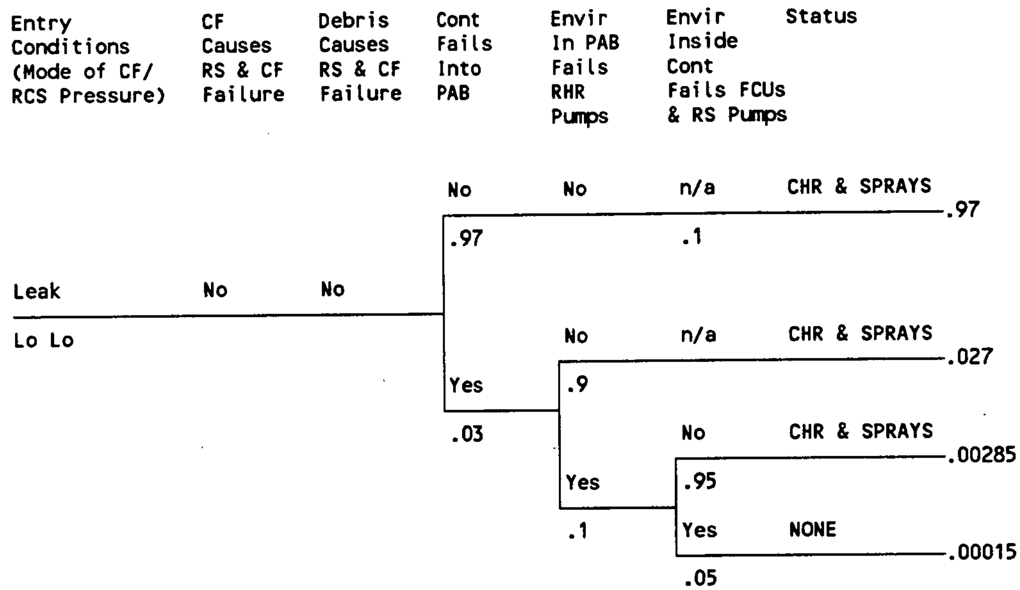
For this case, there is a 0.01 probability that the core debris would be transported to the containment and recirculation sumps failing both the RS and RHR pumps. Core debris could also cause the failure of the fan coolers.

If CHR is not available initially, the probability of RS failure by debris in the sumps is increased to 0.1 because of the decrease in diversity. Therefore for this case, the probability of no CHR or sprays is 0.1. Similarly, if RS is not available initially, the probability of CHR failure is 0.1, and the probability of not having either CHR or sprays is 0.1

Summary for Case B:

	Initial Availability		
	CHR & RS	RS only	CHR only
CHR & SPRAYS	.99	-	-
SPRAYS ONLY	-	.9	-
CHR ONLY	-	-	.9
NONE	.01	.1	.1

Case C: Leak type failure; LO LO RCS Pressure



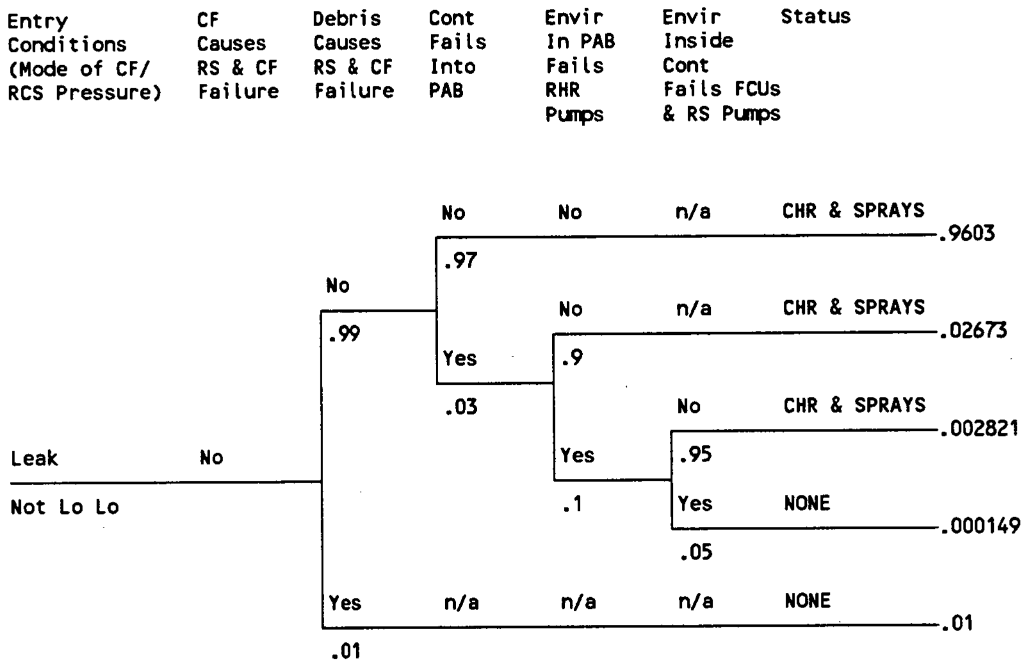
For this case, CHR and RS could fail from environmental conditions inside the containment and in the Primary Auxiliary building (if containment fails into the PAB).

If either CHR or RS is not available initially, the probability of RS or fan cooler failure in the containment from harsh environment is increased from 0.05 to 0.2 (from loss of diversity). Using the above tree logic, the probability for no CHR or sprays is then calculated to be 0.006.

Summary for Case C:

	Initial Availability		
	CHR & RS	RS only	CHR only
CHR & SPRAYS	.99985	-	-
SPRAYS ONLY	-	.9994	-
CHR ONLY	-	-	.9994
NONE	.00015	.0006	.0006

Case D: Leak type failure; Not LO LO RCS Pressure



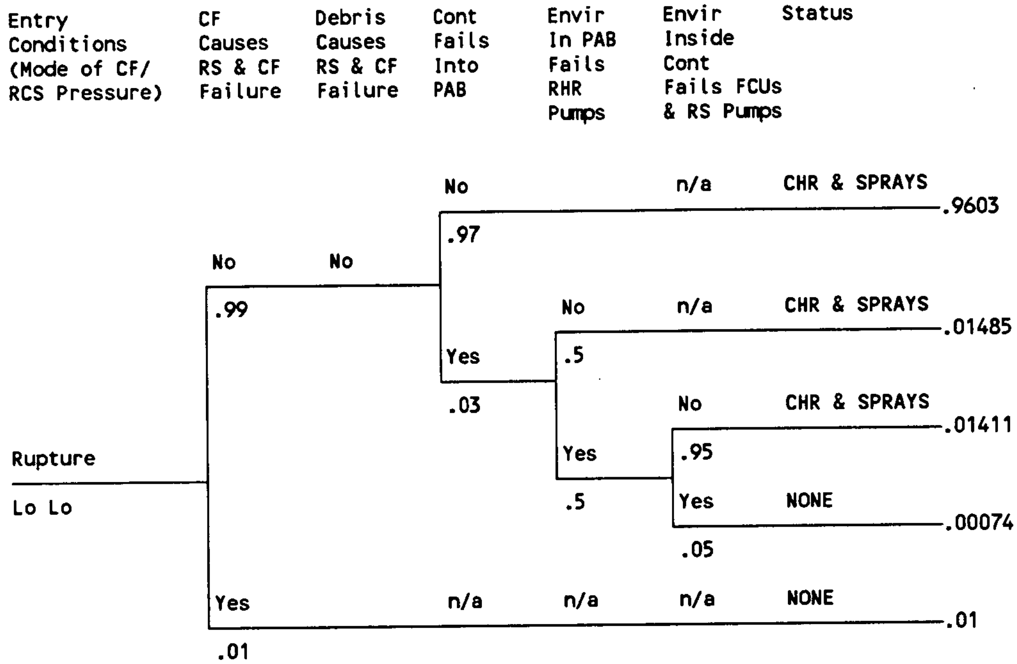
For this case, CHR and RS can be failed by debris the sumps and in the fan coolers, and can also be failed by harsh environmental conditions in the containment and in the PAB (if containment fails into the PAB).

If either CHR or RS is not available initially, the probability of RS or fan cooler failure in the containment from harsh environment is increased from 0.05 to 0.2 (from loss of diversity). Also, the probability of failure from excessive debris in the containment is increased to 0.1. Using the above tree logic, the probability for no CHR or sprays is then calculated to be 0.1006.

Summary for Case D:

	Initial Availability		
	CHR & RS	RS only	CHRonly
CHR & SPRAYS	.9899	-	-
SPRAYS ONLY	-	.9	-
CHR ONLY	-	-	.9
NONE	.0101	.1	.1

Case E: Rupture type failure; LO LO RCS Pressure



For this case failure can be caused directly by containment rupture, or it can be caused by environmental conditions in the containment and in the PAB (if the cobtainment fails into the PAB).

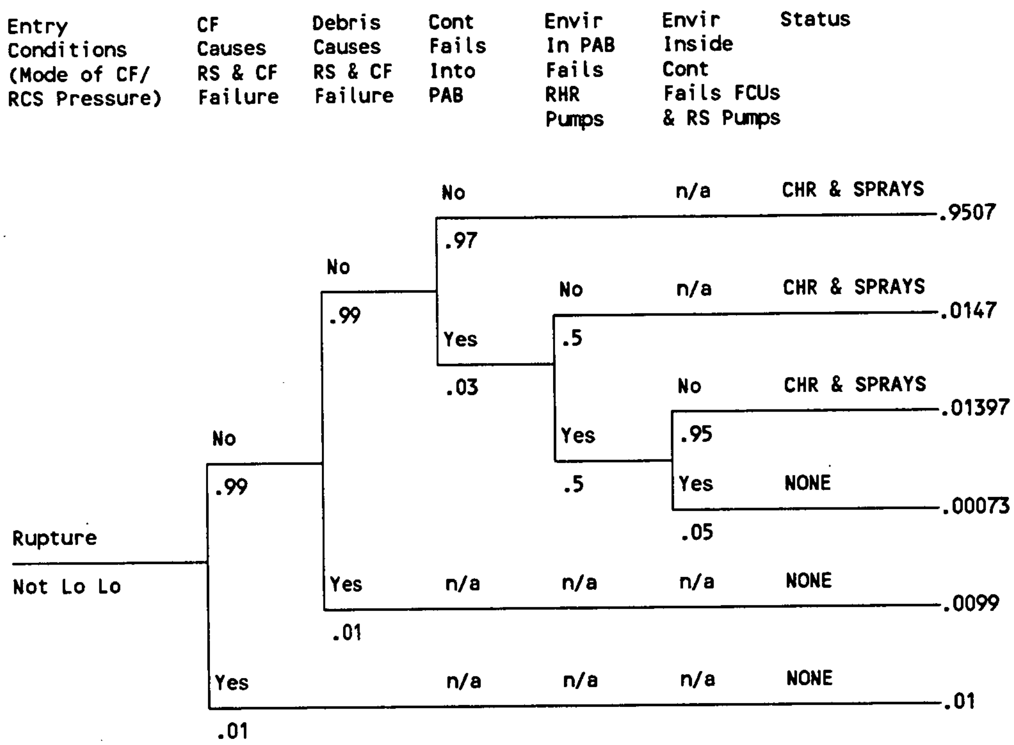
If CHR is not available initially, the probability of RS failure in the containment from harsh environment is increased from 0.05 to 0.2 (from loss of diversity). Also, the probability of direct failure from the rupture is increased to 0.1. Using the above tree logic, the probability for no sprays is then calculated to be 0.1.

If RS is not available initially, the probability of CHR failure in the containment from harsh environment is increased from 0.05 to 0.2 (from loss of diversity). Also, the probability of direct failure from the rupture is increased to 0.1. Using the above tree logic, the probability for no CHR is then calculated to be 0.1.

Summary for Case E:

	Initial Availability		
	CHR & RS	RS only	CHRonly
CHR & SPRAYS	.9893	-	-
SPRAYS ONLY	-	.9	-
CHR ONLY	-	-	.9
NONE	.0107	.1	.1

Case F: Rupture type failure; Not LO LO RCS Pressure



For this case failure can be caused directly by containment rupture, by excessive debris in the containment, or by harsh conditions in the containment and in the PAB (if the cobtainment fails into the PAB).

If CHR is not available initially, the probability of RS failure in the containment from harsh environment is increased from 0.05 to 0.2 (from loss of diversity). Also, the probability of direct failure from the rupture is increased to 0.1. The probability of failure from debris in the sumps is increased to 0.1. Using the above tree logic, the probability for no sprays is then calculated to be 0.192.

If RS is not available initially, the probability of CHR failure in the containment from harsh environment is increased from 0.05 to 0.2 (from loss of diversity). Also, the probability of direct failure from the rupture is increased to 0.1. The probability of failure from debris in the fan coolers is increased to 0.1. Using the above tree logic, the probability for no CHR is then calculated to be 0.192.

Summary for Case F:

	Initial Availability		
	CHR & RS	RS only	CHRonly
CHR & SPRAYS	.9801	-	-
SPRAYS ONLY	-	.808	-
CHR ONLY	-	-	.808
NONE	.0199	.192	.192

4.6.3.5 Debris Cooled Ex-vessel Decomposition Event Tree (EXVCOOL.DET - Figure 4.6-5)

Debris is considered cooled ex-vessel if the debris temperature is reduced to and maintained below the concrete melting temperature.

Event 1: Entry from Prior CET Event (Containment Heat Removal or Recirculation Spray Available Early)

One Branch

Event 2: RCS Pressure at Reactor Vessel Failure (RCSPRESS)

Two Branches

Not LO LO (> 200 psig)
LO LO (≤ 200 psig)

Note: Not LO LO includes PDS RCSPRESS attributes LO HI, HIGH and HI HI. Additionally, LO LO RCS pressures will result from induced hot leg failures. (CET Event PSFAIL = HOT LEG FAILURE)

Branch Probability Type: One/Zero

Quantified Using: PDS Parameter: RCSPRESS and CET Event: PSFAIL

Event 3: Debris Dispersed Out of Cavity (DEBDISP)

Two Branches

Yes (Debris dispersed out of cavity)
No (Debris not dispersed out of cavity)

Branch Probability Type: Split Fraction

Quantified Using: Engineering Judgement

The amount of debris entrained out of the cavity is dependent primarily on the amount of core debris molten in the lower vessel head at vessel breach and on the mode of reactor vessel failure.

It would be expected that the fraction of core debris molten in the lower vessel head is function of the time before vessel failure, the RCS pressure, and the availability of in-vessel debris cooling. However, according to the NUREG-1150 In-vessel Expert's Panel, there is no direct correlation between the amount of core debris released from the vessel at vessel breach to any of the above parameters. However, the experts seem to agree that the maximum fraction of the core ejected is about 60% with a median value of the distribution at 28%. (Ref. 4.6-4, Fig 6-1). In a separate analysis performed by INEL (Ref 4.6-3), results indicated that 17% would be a conservative estimate of the amount of the core debris which would be present as liquid in the lower head of the vessel and available to participate in DCH event at vessel failure. This analysis also suggested that 30% would be an upper limit on this parameter. This INEL calculation suggests that the NUREG-1150 estimates are conservative. For this portion of the analysis, it will be assumed that 30% of the core will be molten at the bottom head and dispersed into the cavity at vessel breach. The remaining 70% of the core will be dispersed at a later time after vessel failure.

The amount of debris dispersed out of the cavity is dependent on the mode of vessel failure which in turn in dependent on the RCS pressure at vessel breach.

Case A: Lo Lo RCS Pressure Sequences

For sequences where the RCS pressure is below 200 psig at the time of vessel breach, the failure would be local and the core debris will pour out in a steady stream. In this case it is very likely that a majority of the debris will not be entrained out of the reactor cavity. Since it is conservative in this case it will be assumed that the debris is never entrained out of the cavity for low pressure sequences.

	Point Est.
Yes (Debris Dispersed)	0.
No (Debris Not Disp.)	1.

Case B: Not Lo Lo RCS Pressure Sequences

For sequences with RCS pressures greater than 200 psig at the time of vessel breach, the high pressure melt ejection (HPME) mode of failure is dominant. In this case it is likely that a majority of the debris released from the vessel at vessel failure will be entrained out of the reactor cavity. In the expert elicitation on In-vessel issues (NUREG/CR-4551), it was estimated that at RCS pressures greater than 2500 psig, the probability of HPME and/or high pressure bottom head failure is 0.92 with a .08 probability being assigned to the pour type failure. For RCS pressures between 200 and 2500 psig, HPME and bottom head failures accounted for 73% of the failure modes. Since an examination of all IP-2 sequences show that RCS pressures are as likely to be in the intermediate range (200 to 2500 psig) as in the high range (>2500 psig), a probability in between .92 and .73 (i.e. 0.82) is chosen for high pressure melt ejection.

	Point Est.
Yes (Debris Dispersed)	.82
No (Debris Not Disp.)	.18

Event 4: Depth of Debris Pool (DEBDEPTH)

Three Branches

Deep	(> 25 cm)
Shallow 10	(< depth < 25 cm)
Very Shallow	(< 10 cm)

The debris depths listed above are based on debris with 100% theoretical density (no porosity).

For pools with depths greater than 25 cm it is problematic whether the debris pools are coolable given a supply of coolant water. For debris pools less than 25 cm deep the debris will be coolable if cooling water is available (Generic letter 88-20, Page 1-8, Section 4 "General Guidance on Containment Performance"). For pools with depths less than 10 cm it is likely that the debris will be able to transfer sufficient energy by radiation and convection to cool the debris to below the concrete melting temperature without cooling water flow to the debris.

Branch Probability Type: Split Fraction

Quantified Using: Engineering Judgement/Calculation

Case A: LO LO RCS pressure

When the vessel fails at low RCS pressure all debris will remain in the cavity and the depth of the debris is assumed to be indeterminant. The depth can be either shallow or deep depending on the spread of the debris within the cavity which is a function of the failure mode of the vessel. A shallow debris pool will occur if the debris covers the entire cavity floor. The total surface area of the cavity floor is 989 ft^2 (91.9 m^2). The maximum debris spread for this case is calculated as follows:

$$h = V / A = 0.21 \text{ m}$$

where

V = The total debris volume (19.6 m^3)

A = The floor area of the cylindrical and keyway portions of the cavity (91.9 m^2)

The volume of debris is calculated as follows:

	Density Volume		
Component	Mass,kg*	kg/m^3	m^3
---------	----------	----- ---	---
Zircaloy	20300	6500	3.1
UO2	98800	10100	9.8
Internal steel	20000	8000	2.5
Lower head steel	34000	8000	4.2
	--------	------	
	156100	19.6	

* All masses are obtained from the IP-2 MAAP input calculations except for the mass of internal steel which was not readily available and is estimated based on other studies.

From the discussion in the previous event (DEBDISP), it is assumed that 30% of the core mass will be ejected at vessel breach. Therefore, the initial volume of ejected debris is 19.6 * 0.3 = 5.9 m^3. The remaining volume will flow out at a later time after vessel breach. (Note: According to NUREG/CR-4551 (Ref. 4.6-1), debris that exits the vessel late after vessel failure and falls into a cavity which is flooded is likely to particulate and be coolable rather than forming a liquid pool, assuming the debris that is already in the cavity is coolable.)

A deeper pool will result if the debris does not spread over the entire cavity but is restricted to a limited portion of the cavity. For example, the debris may be restricted to the area just below the vessel if the ejection is like a pour. The depth in this scenario is defined based on the above equation using the same volume but a floor area equivalent to that of a cylinder with a radius equal to the radius of the reactor vessel.

$h = V / A = .82 \text{ m}$

where:

$A =$ floor area (24 m^2).

As can be seen from the above calculations, the debris depth in the cavity can be defined either as shallow or deep depending on the degree of spread over the cavity floor. Since the IP-2 cavity is sloped away from the reactor centerline, the likelihood of debris spread will increase. In addition, the majority (approximately 70%) of the debris will be ejected after vessel breach and will particulate, thus enhancing spread. Therefore, a probability of 0.6 is assigned to a shallow pool and the other 0.4 assigned to deep pools.

	Point Est.
Very Shallow	0.
Shallow	.6
Deep	.4

Case B: High RCS Pressure and Debris Not Entrained Out of Cavity

If the RCS pressure at the time of vessel failure is high and the debris is not dispersed out of the cavity the pool depth can again be shallow or deep. Since the pressure is high it is more likely that the debris will be evenly distributed throughout the cavity so the probabilities are defined as follows:

	Point Est.
Very Shallow	0.
Shallow	.9
Deep	.1

Case C: High RCS Pressure and Debris Entrained Out of Cavity

If the RCS pressure is sufficiently high to entrain the debris out of the cavity then the most likely pathway for this debris is to follow the in-core instrument tubes through the keyway and up to the 46 foot floor level inside the crane wall. This area is open to the containment atmosphere and is therefore coolable via Recirculation Sprays. In this event the pool depth is defined to be very shallow ($h < 10$ cm) since the floor area is much greater than 100 m^2. However, a 10% probability is assigned to cases where the debris might be trapped in corners or against equipment and could be greater than 10 cm in depth. Therefore, for the 30% of the core debris ejected at vessel breach, the probability of a very shallow pool is 0.9 and the probability of a shallow pool is 0.1. The remaining 70% of the core debris will be ejected later in time at low pressure into the cavity. This will tend to particulate and will likely be coolable. Therefore, of this 70%, a fraction of .9 will be shallow and .1 will be deep.

The calculation for the branch fractions for this case is then summarized below.

For very shallow pools:

```
prob.  =   fraction ejected     *    prob. of very
           at high pressure          shallow depth
           to upper cont.            in upper cont.

       =   0.3 * 0.9 = 0.27
```

For shallow pools:

```
prob.  =   fraction ejected     *    prob. of
           at high pressure          shallow depth.
           to upper cont.            in upper cont.

       +   fraction ejected     *    prob. of
           at low pressure           shallow depth
           to cavity                 in cavity

       =   (0.3 * 0.1) + (0.7 * 0.9)  =  0.66
```

For deep pools:

prob.	=	fraction ejected at low pressure to cavity	*	prob. of deep pool in cavity
	=	0.7 * 0.1 = 0.07		

Summary:

	Point Est.
Very Shallow	.27
Shallow	.66
Deep	.07

Event 5: Cooling Water To Debris Ex-vessel (COOLWATER)

Two Branches

Yes (Cooling Water To Debris Ex-vessel)
No (No Cooling Water To Debris Ex-vessel)

Branch Probability Type: One/Zero

Quantified Using: CET Event: HR-EARLY

From the discussion for the previous event, it can be concluded that debris entrained out of the cavity will very likely form pools that are less than 10 cm deep and are therefore coolable even without the presence of water. On the other hand, debris remaining in the cavity is likely to be deep and water supply is needed to have a chance to cool this debris. Due to the keyway design in IP-2, water will collect in the cavity from sources such as containment sprays, primary coolant inventory from breaks or open relief valves, or from condensation of steam (IPPSS, page 2.5-6). Therefore, for these cases, water is assumed to be present.

For the debris to be cooled long term, CHR must also be available (in addition to the presence of water). Therefore, fan coolers or RHR heat exchangers must function for long term heat removal.

Event 6: Debris Cooled Ex-vessel (EXVCOOL)

Two Branches

Cooled
Not Cooled

For sequences where long term heat removal is available and where with water is being supplied to the debris the following conditions are considered. For deep pools (depths greater than 25 cm) it is problematic (0.5 probability of success) whether the debris pools are coolable given a supply of cool water. For debris pools less than 25 cm deep the debris is coolable if cooling water is available (GL 88-20, page 1-8). For very shallow pools (pool depth less than 10 cm) it is likely that the debris will be able to transfer sufficient energy by radiation and convection to cool the debris to below the concrete melting temperature without cooling water flow to the debris. (Ref. 4.6-1, Appendix A, Pages A1.1-66 - A1.1-68). Therefore very shallow pools are assumed to be coolable (probability of success = 0.9) even without the presence of water. Debris pools with depths greater than 10 cm are assumed non-coolable without water and long term containment heat removal. [Note: Without containment heat removal, temperature and pressure rise will continue and can, over a long period of time, fail the containment even for the very shallow debris pool scenario. However, this heatup is gradual and the long time frame available (in excess of 24 hours) will allow for operator, power, or equipment recovery.

Case A: Deep Pool With Cooling Water

	Point Est.
Cooled	.5
Not Cooled	.5

Case B: Deep Pool With No Cooling Water

	Point Est.
Cooled	0.
Not Cooled	1.

Case C: Shallow Pool With Cooling Water

	Point Est.
Cooled	1.
Not Cooled	0.

Case D: Shallow Pool With No Cooling Water

	Point Est.
Cooled	0.
Not Cooled	1.

Case E: Very Shallow Pool With Cooling Water

	Point Est.
Cooled	1.
Not Cooled	0.

Case F: Very Shallow Pool With No Cooling Water

	Point Est.
Cooled	.9
Not Cooled	.1

4.6.3.6 Mode of Late Containment Failure Decomposition Event Tree (CF-LATE.DET - Figure 4.6-6)

Event 1: Entry from Prior CET Event (Debris Cooled Ex-Vessel)

One Branch

Event 2: Power Available Prior to Reactor Vessel Failure (POWRECRV)

Two Branches

Yes
No

This event assess whether there is AC power available to operate the Containment Sprays and Fans at the time of reactor vessel failure.

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: TRANLOCA and POWRECOV

Event 3: Power Recovery Late (POWRECLAT)

Two Branches

Yes
No

This event assess whether AC power is recovered late in the accident sequence (after RV failure but before containment integrity is threatened by long term steam overpressurization) given that AC power was initially lost and not recovered prior to RV failure.

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: POWRECOV

Event 4: Recirculation Sprays Available Early (RS-EARLY)

Two Branches

Yes
No

This event assesses whether Recirculation Sprays are available "early" in the accident sequence (prior to containment being threatened by steam overpressurization).

This requires that AC power is available (either always available or recovered) and that the sprays have not failed earlier.

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: RECSPRAYS, CET Event: HR-EARLY

Event 5: RCS Pressure at Vessel Failure (RCSPRESS)

Four Branches

LO LO Pressure (< 200 psig)
Not LO LO (> 200 psig)

Note: Not LO LO includes pressure ranges
LO HI, HIGH and HI HI Pressure

Branch Probability Type: One/Zero

Quantified Using: PDS Parameter: RCSPRESS CET Parameter: PSFAIL

Event 6: Debris Cooled Ex-vessel (EXVCOOL)

Two Branches

Cooled
Not Cooled

Branch Probability Type: One/Zero

Quantified Using: CET Event: EXVCOOL

Event 7: "Late" Hydrogen Burn Fails Containment (LATEH2)

Two Branches

Yes
No

In NUREG/CR-4551 it was judged that the only time that a hydrogen burn of sufficient magnitude to challenge the integrity of the Surry containment might occur would be during rapid deinerting. This statement will also apply to IP-2 since the IP-2 containment is similar to the Surry containment in strength (see section 4.4). The IP-2 containment is sufficiently robust that a hydrogen burn at relatively low hydrogen concentrations will not challenge the containment. Furthermore, it is very unlikely that a large hydrogen concentration could accumulate in a deinerted containment because of the plethora of ignition sources that would be expected to be available. For example, for the containment to remain deinerted for long periods of time following core damage containment heat removal must be available or else steam generation would soon cause the containment to reach an inert condition. The availability of AC power and the operation of electrical equipment inside containment would almost certainly assure that ignition sources would be available to prevent accumulation of very high hydrogen concentrations. Consequently, it is judged that the only time that a high hydrogen concentration could occur in conjunction with a deinerted containment would be late in accident sequences without sprays or containment heat removal where the sprays/CHR are recovered. This situation might occur, for example, for a SBO accident with later power recovery.

Bounding Calculation

A calculation was performed to evaluate the upper levels of pressure that might result from hydrogen combustion in the containment. For 100% metal-water reaction, and assuming a 50% volume fraction of steam, the hydrogen concentration would be 6.4%. Complete combustion cannot be expected at this concentration. At 66% burn efficiency, the peak adiabatic pressure would be 108 psia. This conservative calculation would lead to a failure probability estimate of 4 percent. If the sprays have just operated such that there is no steam in the containment, the hydrogen concentration would rise to 12.8%. Complete combustion would result in an adiabatic peak pressure of less than 90 psia, which is not a significant challenge to containment integrity.

Three cases are considered below.

Branch Probability Type: Split Fraction

Quantified Using: PDS Parameter: RCSPRESS
CET Event: EXVCOOL

Case 1: Early Hydrogen Burn Occurs

If an early hydrogen burn at vessel failure has occurred then insufficient oxygen is available to react with hydrogen to threaten containment. It is assumed that all sequences with high pressure melt ejection will result in sufficient hydrogen combustion at vessel failure to render the late hydrogen burn threat negligible.

	Point Est.
Yes-Late H2 Burn Fails Cont	0.
No	1.

Case 2: Debris Cooled Ex-vessel

For sequences with no debris concrete attack then insufficient additional hydrogen will be produced over that generated in-vessel to establish a potential concentration that could threaten containment integrity.

	Point Est.
Yes-Late H2 Burn Fails Cont	0.
No	1.

Case 3: No Early Hydrogen Burn has Occurred and Debris is Not cooled Ex-vessel

For this case the results from the conservative bounding calculation discussed above is used.

	Point Est.
Yes-Late H2 Burn Fails Cont	.04
No	.96

Event 8: Containment Heat Removal Available (CNHEATREM)

Two Branches

Yes
No

For sequences without containment heat removal eventual over-pressure containment failure will occur. With CHR containment steam over-pressure failure is prohibited. Non-condensible gas generation alone will not result in over-pressure failure of the IP-2 containment.

Branch Probability Type: Zero/One

Quantified Using: CET Parameter: HR-EARLY

Event 9: Mode of Late Containment Failure (CF-LATE)

Four Branches

No Late CF
Leak
Rupture
Catastrophic Rupture

The characteristics of each of these failure modes is discussed in Section 4.4. The composite aggregate containment fragility curve shown in Table 4.6-3 was used to evaluate the probability of containment failure for each DET pathway. The mode of containment failure for each DET pathway was assessed as follows. It was judged that 1) a Leak type failure was most likely for failure pressures less than 135 psig (150 psia), 2) a Rupture type failure was most likely for failure pressures between 135 and 155 psig (150 - 170 psia), and 3) a catastrophic rupture was most likely for failure pressures greater than 155 psig (170 psia). Note that unlike the early containment failure analysis where containment loading were due to fairly rapid transient events (e.g. DCH, vessel blowdown, or H_2 combustion) for late over-pressure failure the loading rate is relatively slow and we assume that any containment failure mode results in a hole size which is sufficiently large to at least terminate the pressure rise in containment. The containment over-pressure fragility curve and the conditional probabilities for each mode of failure given in Table 4.6-3 were used to develop the following conditional probabilities for each mode of containment failure. (See also the discussion on the DET for Mode of Early Containment Failure.)

The probabilities for each mode of containment failure were evaluated by numerically integrating the following equations:

$$P_i = \frac{\int_{70psig}^{180psig} P_f(P) \times P_{c-i}(P)\, dp}{\int_{70psig}^{180psig} P_f(P)\, dp}$$

Where:

P_i = the probability of containment failure by mode i

$_i$ = leak or rupture

P = containment pressure (psig)

$P_f(P)$ = probability density function for containment failure as a function of pressure

$P_{c-i}(P)$ = the conditional probability of containment failure by mode i at pressure P

Solution of this equation with the data from Table 3 yields

P_{leak} = .617

$P_{rupture}$ = .306

$P_{cat\ rupture}$ = .078

These values give the probabilities of containment failure for each failure mode for gradual pressurization where containment pressurization is unmitigated (i.e. pressure continues to increase until failure occurs).

4.6.3.7 No Late Recirculation Spray Failure Decomposition Event Tree (RS-LATE.DET - Figure 4.6-7)

Event 1: Entry from Prior CET Event (Mode of Late Containment Failure)

One Branch

Event 2: Recirculation Sprays Failed Earlier or Power Not Available Late (RSFAIL-E)

Two Branches

Failed
Not Failed

Branch Probability Type: One/Zero

Quantified Using: PDS Parameters: TRANLOCA,RECSPRAYS and POWRECOV
CET Event: HR-EARLY

Event 3: Mode of Late Containment Failure (CF-LATE)

Four Branches

No late CF
Leak
Rupture
Catastrophic Rupture

Branch Probability Type: One/Zero

Quantified Using: CET Event: CF-LATE

Event 4: Containment Heat Removal Available (CNHEATREM)

Two Branches

Yes
No

Branch Probability Type: Zero/One

Quantified Using: CET Event: HR-EARLY

Event 5: Recirculation Spray Available Late (RS-LATE)

Two Branches

No Failure
Failure

Branch Probability Type: Split Fraction

Quantified Using: Engineering Analysis/Judgement

Failure of Recirculation Spray late in time can be caused by failure of the containment itself or by failure of the Recirculation pump motors and the RHR pump motors.

For the Nc CF, Leak and Rupture mode failures, containment failure will not directly fail the recirculation spray function. (Ref. 4.6-1, Appendix A, page A.1.1-56) For the catastrophic rupture type failures, it was estimated that there is a 10 percent chance of failing recirculation sprays at Surry. Since there are four spray headers at Surry compared to two at IP-2, the probability of spray failure at IP-2 from catastrophic rupture is assumed to be 0.3

Failure of the recirculation pump motors can be caused by environmental conditions (temperature, pressure, humidity, radiation) in the containment late in the accident sequence. At the median containment failure pressure, the temperature of the containment atmosphere will be approximately 350 °F and possibly much higher if the containment atmosphere is superheated. Unlike the early pressure transients arising from vessel blowdown, DCH, hydrogen burns etc. which are likely to be short lived, long term containment overpressurization will expose equipment in containment to elevated temperatures for long periods of time. Thus, the RS pump seals and motors may be exposed to temperatures and pressures well in excess of their peak qualification temperature for a long period of time. Therefore it is believed that the Recirculation Spray pumps will likely fail if long term containment heat removal is not available.

In addition to the Recirculation Spray pumps, the RHR pumps can be used for the recirculation spray function. These RHR pumps are located in the Primary Auxiliary Building and will not initially be affected by conditions inside the containment. Eventually, however, the failure of the containment into the auxiliary building may fail these pumps. This will be considered later. In addition, the RHR pumps may fail due to the environmental conditions (temperature, pressure, humidity, radiation) in the containment late in the accident sequence. The only significant failure mechanism is for the pump seals to fail as a result of the temperature of the water passing through the pumps.

Like the RS pumps, the RHR pumps are qualified for the severe accident environment. At the median containment failure pressure, the temperature of the containment Sump water will be approximately 350 °F. Long term containment overpressurization will expose equipment in containment to elevated temperatures for many hours or days. The RHR pump seals may be exposed to temperatures well in excess of their peak qualification temperature for a long period of time since containment heat removal is not available. However, it is considered unlikely that the RHR pumps will fail within the 24 hour mission time being used for this study (probability of failure of 0.1) because the RHR seal cooling is gravity fed with city water as a backup.

The probability that the containment will fail into the Primary Auxiliary Building is estimated by taking the ratio of the containment/auxiliary building interface area and the total containment surface area. This calculation is documented in the writeup for event CF-PAB for the HR-EARLY DET which shows this ratio to be 0.026. Given that the containment has failed into the auxiliary building, the effect of the environmental conditions (temperature, pressure, humidity, radiation) in the auxiliary building on the RHR pump motors will depend on the mode of containment failure. A leak type failure is characterized by a failure size of approximately 0.1 ft^2 (4 inch diameter hole). Because of the limited leak rate from containment and the isolated location of the RHR pump motors it is judged to be unlikely that both RHR pump motors will fail (failure probability of .1). Rupture or catastrophic rupture type failures are characterized by a failure sizes of approximately 1.0 ft^2 (14 inch diameter hole) or larger. Because of the much larger leak rates from the containment and uncertainties as to the actual peak temperatures the RHR pump motors can withstand it is judged that failure of both RHR pump motors is indeterminant (failure probability of 0.5).

Case A: No Late CF, No long term heat removal

1) Since there is no containment failure there is no direct mechanism to fail the spray headers.
2) Even if the containment environment fails the RS pumps, the RHR pumps should be functional since they reside outside the containment.
3) Probability of long term failure of RS and RHR pump seals = 0.1

Total prob of failure = 0.1

	Point Est.
No Late RS Failure	.9
Yes - RS Failure Late	.1

Case B: Leak Type Failure, No long term heat removal

1) Leak failure implies no direct failure of spray headers
2) Probability of failure from environmental conditions is equal to the probability of RS pumps failing * probability of containment failing into the PAB * probability of RHR pumps failing = 1.0 * 0.026 * 0.1 = 0.0026
3) Probability of long term failure of RS and RHR pump seals = 0.1

Total prob of failure = 0.0026 + 0.1 = 0.1026

	Point Est.
No Late RS Failure	.897
Yes - RS Failure Late	.103

Case C: Rupture Type Failure, No long term heat removal

1) Rupture failure implies no direct failure of spray headers
2) Probability of failure from environmental conditions is equal to the probability of RS pumps failing * probability of containment failing into the PAB * probability of RHR pumps failing = 1.0 * 0.026 * 0.5 = 0.013
3) Probability of long term failure of RS and RHR pump seals = 0.1

Total prob of failure = 0.013 + 0.1 = 0.113

	Point Est.
No Late RS Failure	.4
Yes - RS Failure Late	.6

Case D: Catastrophic Rupture Type Failure, No long term heat removal

1) With catastrophic rupture the probability of containment failure failing the spray headers is 0.3
2) Probability of failure from environmental conditions is equal to the probability of RS pumps failing * probability of containment failing into the PAB * probability of RHR pumps failing = 1.0 * 0.026 * 0.5 = 0.013

3) Probability of long term failure of RS and RHR pump seals = 0.1

Total prob = 0.3 + (1-.3)0.013 + (1-.3)(1-.013)0.1
of failure
= .378

	Point Est.
No Late RS Failure	.622
Yes - RS Failure Late	.378

Case E: Catastrophic Rupture Type Failure, Long term heat removal available

In this case, the only failure mechanism is directly from containment failure (probability = 0.3)

	Point Est.
No Late RS Failure	.7
Yes - RS Failure Late	.3

Case F: No early CF, Leak, or Rupture Type Failures, and Long term heat removal available

In this case, there is no late failure of the RS system.

	Point Est.
No Late RS Failure	1.
Yes - RS Failure Late	0.

4.6.3.8 Containment Failure Long Term Decomposition Event Tree (CF-LONG.DET - Figure 4.6-8)

This tree is entered only for sequences with operable Recirculation Sprays and containment heat removal and with the debris **NOT** cooled ex-vessel. CHR operation assures that containment over-pressure failure from gradual steam generation will not occur. Hence, only basemat melt-through is possible as a long term containment failure mechanism. In addition, operation of the Recirculation Sprays or containment fans indicate that cooling is being supplied to the debris. However, the debris is not in a coolable configuration for these sequences.

Event 1: Entry from Prior CET Event (Recirculation Spray Available Late)

One Branch

Event 2: Containment Failure Long Term (CF-LONG)

Two Branches

No Late Late CF
Melt-through (Basemat Melt-through)

Branch Probability Type: Split Fraction

Quantified Using: NUREG 1150-NUREG/CR-4551

For non-coolable debris pools with an overlying water layer NUREG/CR-4551 provides the following estimates for the probability of basemat melt-through:

P(BMT) = .25	for core concrete interactions (CCI) involving a large fraction of the core debris
P(BMT) = .05	for intermediate CCI

The assumption is made that "deep pools" used in this analysis (see DET for Debris Cooled Ex-vessel) can be equated with the NUREG/CR-4551 large CCI category and "shallow pools" with the intermediate CCI category.

In the DET for Debris cooled Ex-vessel, it was assumed that if debris cooling was available, all shallow pools are coolable. If debris cooling was not available, overpressure failure would occur and for these cases we can neglect basemat melt-through since the offsite consequences from basemat melt-through are small compared to that for over-pressure failure.

Since the entry conditions into this DET are that debris cooling is available and the debris is not cooled ex-vessel, we can assume that this DET will apply only for cases where the debris depth is deep and CCI involves a large fraction of the core debris. Therefore, the probability for basemat melt-through for these cases is 0.25.

	Point Est.
No Late Late CF	.75
Melt-through	.25

4.6.3.9 Event V Auxiliary Building Fission Product Retention Effectiveness Decomposition Event Tree (AUXBLDG.DET - Figure 4.6-9)

Event 1: Entry from Prior CET Event (Event V LOCA)

One Branch

Event 2: Event V LOCA Break Covered by Water Pool in Auxiliary Building (BREAKCOV)

Two Branches

Yes - (Break covered)
No - (Break Uncovered)

If there was an interfacing LOCA outside the containment at IP-2, the most probable location of failure would be into the Auxiliary Building. The probability that an interfacing LOCA would lead to a submerged release in this building would depend on the location of the break (elevation of pipe rupture) relative to the depth of water which would accumulate on the floor from this break. An inspection of the IP-2 drawings shows that there is a doorway at the bottom elevation of the Auxiliary Building, and that any water on the floor of this building will drain out of the building. Therefore, for this study, it is assumed that any break into the Auxiliary Building will not be submerged and that the Auxiliary Building will not be effective for the mitigation of any fission product release.

Branch Probability Type: Split Fraction

	Point Est.
Yes - (Break Covered)	0
No - (Break Uncovered)	1

Event 3: Event V Auxiliary Building FP Retention Effectiveness (AUXSGSEC)

No Branching

Branch Probability Type: Summary Event

This event has no branching. It is used solely to categorize the outcomes of each pathway to transmit information back to the CET.

4.6.4 Quantified CETs

The quantified CETs for each IP-2 PDS end point are attached in the following pages. These CET endpoint probabilities are conditional upon the occurrence of the PDS.

4.6.5 References for Section 4.6

4.6-1 NUREG/CR-4551, Volume 3, Revision 1, Part 1 (Main Report) and Part 2 (Appendices) "Evaluation of Severe Accident Risks : Suury Unit 1", October 1990.

4.6-2 NUREG/CR-4896, "Containment Loads Due to Direct Containemnt Heating and Associated Hydrogen Behavior: Analysis and Calculations with Contain Code", MAy 1987.

4.6-3 Presentation by Eltiwilia to Advisory Committee on Nuclear Safety (ACRS), Subcommittee on Nuclear Safety, Bethesda, Maryland, March 21, 1990.

4.6-4 NUREG/CR-4551, Volume 2, Revision 1 ,Part 1 " Evaluation of Severe Accident Risks: Quantification of Major Input Parameters", 1990.

SECTION 4.7

SOURCE TERM CHARACTERIZATION

4.7 Source Term Characterization

The end points of the Containment Event Trees (CET) represent the outcomes of possible in-containment accident progression sequences. These endpoints represent complete severe accident sequences from initiating event to release of radionuclides to the environment. The Level 1 system information is passed through to the containment evaluation in discrete plant damage states. An atmospheric source term may be associated with each of these containment sequences. Because of the large number of CET sequences and because of similarities in the sequence characteristics, however, it is neither necessary nor practical to develop a source term estimate for each containment sequence. Sequences with similar characteristics are therefore grouped into release categories to reduce the required source term assessment effort.

4.7.1 Release Category Grouping Parameters

The first step in the source term assessment effort is to identify the sequence characteristics which are most important to definition of the source term. These characteristics are identifiable from the Plant Damage State (PDS) characteristics and from the Containment Event Tree CET sequence characteristics since one of the primary objectives in the PDS grouping and CET evaluation has been to define those events and conditions most important to source term assessment. This selected set of sequence characteristics important to source term assessment are used as grouping criteria to define the release categories and the associated source term magnitude, composition and timing.

The containment sequence characteristics selected for use in definition of the Indian Point 2 source term release categories are:

Event V/SGTR
Debris Cooled In-Vessel
Alpha Mode Containment Failure
Status of Containment Isolation
Time of Containment Failure (relative to core melt)
Time Period of Recirculation Spray Operation
Mode/Location of Containment Failure

The reasons for selection of these parameters for use in defining the different release categories are discussed below.

Event V/SGTR

Containment building natural and engineered mitigation features are ineffective in reducing fission product releases if the accident causes opening of an unobstructed path directly from the Reactor Coolant System to a point outside of the containment gas volume pressure boundary.

The significant ways that this can occur are via an unmitigated steam generator tube rupture (SGTR) with a subsequent failure to isolate the steam generator (eg. due to failure to close a secondary side isolation valve or a safety relief valve failing to reclose) or an interfacing system LOCA (Event V). Additionally, the containment event tree assesses the probability for an induced SGTR as a result of high RCS temperature and pressures. This form of SGTR rupture is combined with the SGTR initiating event class in which the steam generator is isolated and the safety relief valve succeeds in reclosing after vessel failure. This combination is appropriate since, in the induced SGTR case, conditions will exist such that the secondary safety/relief valves will be passing a mixture of steam and gas and are considered to be far less likely to fail stuck open. In any event, the induced SGTR frequency is much lower that of the SGTR frequency as an initiating event.

The Event V and SGTR classes are explicitly treated in the release category logic because they represent the two major ways that fission products can be released outside of containment without any significant containment natural process or system mitigation. They can be expected therefore to result in significant releases.

For interfacing system LOCAs, the failure is most likely to occur into the PAB due to failure of the motor operated valves between the RCS and the RHR system, and subsequent failure of the low pressure RHR suction piping. If this failure occurs outside of containment, it represents an Event V scenario. (At Indian Point 2, a portion of the low pressure piping is actually inside of containment. Breaks in this portion of the piping are not interfacing system LOCAs and do not contribute significantly to the "regular" LOCA class. Because of the size of the opening, subsequent events in containment do not affect the source term significantly. The PAB is not likely to be flooded by a pipe break ssince there exists a significant open liquid flow path to the outside at about the lowest level of the building. Further the PAB because of its light construction at certain points cannot be expected to retain much of the leakage flow. For these reasons, the Event V source term category is conservatively characterized solely by the occurence of the event.

The most frequent SGTR events differ from the interfacing LOCA in that they do not result in continuing significant release for an extended period of time. The difference between the two classes of SGTR is this - if the safety relief valve which is releasing the secondary side overpressure can reseat then the volume of gaseous and volatile fission products released during core damage is relatively low (being pressurized) and tends to only displace the steam in the steam generator and steam lines. The potential for release is terminated when the RCS fails and the pressure drops to the containment level. Consequently the fission product releases are significantly smaller than when the secondary side remains open to the atmosphere.

The ruptured steam generator is assumed to be dry at the time of the core damage. No further category characteristics are required to define this type of sequence and SGTR core melt sequences are assigned to one of two release categories depending on the valve status as discussed above.

The following characteristics are assessed for sequences other than the interfacing LOCA and SGTRs.

Debris Cooled In-Vessel

This characteristic is important since there is a significant probability of arresting the core-melt process in-vessel, thus preventing vessel failure, ex-vessel release (core-concrete interaction) processes and containment failure.

If the core melt process is arrested in-vessel, then the next and only major question would be if the containment is isolated. The containment integrity is not challenged for accident sequences terminated in-vessel, so only isolation failures would allow significant release to the atmosphere.

Alpha Mode Containment Failure

This attribute is considered only for sequences where the core melt process has not been arrested in-vessel.

The alpha mode failure is potentially important because it allows the direct release of fission products to the atmosphere at the time of vessel failure. This is because of the assumption that the same dynamic forces that cause failure of the top closure head of the vessel also cause immediately a large area failure in the containment. Given this gross energetic failure, it is not expected that there will be any mitigating factors and no further characteristics are questioned for this category.

Alpha mode failures are included as a source term characteristic and a CET heading because the divergence of expert opinion concerning the potential for this phenomena make the uncertainties regarding this phenomena large and, at the upper end of the uncertainty range, the contribution of alpha mode failures to the probability of early containment failure may not be negligible.

Containment Building Isolation Status

This attribute is considered important because any fission products in the containment atmosphere are released to the environment early (i.e. near the time of core melt) and continuously, if the containment is not isolated.

In this case, the effective available time for fission product deposition and possible spray washout in containment is reduced. The size of the most likely isolation failure path is large enough so that even if a later larger area containment failure were to occur it should not significantly increase radionuclide release magnitudes.

Time of Containment Failure

This release category attribute is considered important because it affects the time available for fission product release mitigation by natural removal processes and spray washout. It applies to all CET sequences that do not involve loss of isolation, alpha mode failure, or core melt arrest in-vessel.

Containment failure times are assessed in the CETs for the relevant sequences. The times selected as significant are Early, Late, and Late Late (very late). Early containment failure is at, or near, the time of reactor vessel failure. Late containment failures occur several hours after vessel failure. Late Late is a time longer than Late, say at least 24 or more hours after vessel failure, and represents an ultimate failure mode of containment. As discussed in respect to the CET, the actual mode is somewhat uncertain as the analyses are uncertain extrapolations. It may be considered to be, nominally, base mat meltthrough. Certainly the floor is being attacked. Some discussions elsewhere have indicated the possibility that this attack rate may be reduced or even halted because of natural processes (extended debris mass, extended heat conduction possibilities, etc.). However some other form of overtemperature or overpressure failure cannot be ruled out.

The possibility of no containment failure exists and is assigned to its own unique source term category.

Time Recirculation Sprays Operate

This attribute is considered significant because it determines whether or not fission product washout occurs in the containment. It implicitly affects the amount of ex-vessel fission product and aerosol release by cooling the debris on the floor below the point where a core-concrete interaction occurs and/or by covering the debris with a layer of water. This attribute also affects the energy level (temperature) of the release.

The possible time periods over which Recirculation Spray operation is considered are:

- Continuous - the sprays are operational from the time core melting starts and fission products are released from the RCS and continue to operate indefinitely.

- Early Only - the sprays are operational from the time of initial core damage up to a few hours after vessel failure

- Late Only - the sprays come on several hours after vessel failure but prior to a late containment failure in sufficient time to reduce fission product release from core/concrete interactions. It is conservatively assumed in this work, that the sprays can come on late only if power is recovered prior to containment failure in SBO sequences.

- Never - the containment sprays do not operate in the recirculation mode. The containment sprays may have operated in the injection mode, but this is not considered effective for fission product removal because of timing considerations.

This characteristic is determined for sequences that have either early or late containment failure. It is not relevant to no containment failure, and melt arrested in-vessel sequences. It is also not considered relevant to late-late containment failure (e.g. basemat meltthrough) sequences.

The bases for selecting the particular time period to assign are based on the branch attributes that the CET sequence has for the early and late spray operability questions in the CET. Thus for release category characteristics, the definition of "EARLY" and "LATE" are those used in the CET.

Mode of Containment Building Failure

This attribute is important because it governs the rate at which fission products are released to the atmosphere. It also affects the magnitude of the release by governing the time available for effective fission product attenuation in containment.

The two attributes considered significant are leak-type or rupture. These are evaluated using the branch attributes for the CET headings Mode of Early Containment Failure and Mode of Late Containment Failure so the definitions of leak, rupture and catastrophic rupture are those employed in the CET. (Rupture and Catastrophic Rupture in the CET are both assigned to the rupture class in the source term bins because of the low frequency of the catastrophic case and the similarity of releases.)

4.7.2 Release Category Grouping Logic

The approach to the definition of release categories is similar to that discussed in Section 4.3 for the definition of plant damage states. It consists of construction of a logic diagram with the grouping criteria defined above as headings. The end points on the logic diagram represent unique source term categories with their individual characteristics defined by the pathway through the logic diagram.

The goal of the grouping process is to develop the minimum number of release categories necessary to distinguish the important combinations of sequence characteristics that can result in distinctly different atmospheric source terms. The quantified source term category grouping logic diagram developed for the Indian Point

2 plant is shown as Figure 4.7-1. It defines 26 release categories. An additional non-operative heading has been added to record the assignment of the source term bins to release category types as described in Section 4.7.3 below.

Briefly, the quantification of the STC is as follows:

- Each end point on each CET is assigned to a STC based on the STC characteristics defined in the STC logic diagram.
- The dependent probability of each CET end point is multiplied by its corresponding (entry) plant damage state frequency.
- The probability x frequency for each CET end point is then aggregated into the assigned STC bin.

The summed values for each STC are shown on Figure 4.7-1 in the extreme right hand column. Then values for each branch point are derived by summing 'backwards' the values for each path stemming from this branching point. This operation is carried progressively until the single 'entry' path at the left of the diagram is reached. These values are shown at each branching point of the STC diagram. The branch frequencies at each of the headings (except for Isolation Status, Alpha, and Release Type) are depicted graphically in Figures 4.7-2 through 4.7-6.

It is a straightforward operation to find the contribution of each plant damage state to each source term category. The importance (percentage contribution) of each PDS contributing more than one percent to each STC is given in Table 4.7-1. Similarly, Table 4.7-2 lists each important contributor (more than 5 percent) CET end point to each STC.

4.7.3 Release Category Source Term Characteristics

The source term magnitude, composition, and timing for each release category can be defined using the following methods:

1) Deterministic analysis of representative sequences with an accident progression source term assessment code such as MAAP, or

2) By reference to past analysis results such as NUREG-1150, IDCOR, IPPSS, other past PRAs, etc.

For the Indian Point 2 IPE, method 1 was primarily utilized with some reference to other studies as well. MAAP calculations were performed to assess the source terms for eight different sequences. The release fractions for the 26 source term categories were then characterized by similarity to one of the calculated source terms, or in two special low frequency or low release cases by reference to IPPSS values. An effort was made to introduce some variety into the sequence selection (that is, not using the same Level 1 sequences for all calculations). The reason for the variety is both to illustrate the various ways in which the accident might progress, to give diversity to the analyses, and to increase the breadth of the material covered in this report. The sequences modeled for these runs are listed in Table 4.7-3.

The radionuclide release fractions for the analyzed release categories are shown in Table 4.7-4.

The release fractions are listed by MAAP "species". In MAAP, once fission products leave the core in-vessel or core debris ex-vessel, the chemical state is "frozen" and defined by the twelve species listed in Table 4.7-5. The chemical state is important in determining the transition between vapor and aerosol forms which affects the deposition and retention of fission products.

Each fission product specie can exist, in MAAP, in up to four states in each region of the containment and of the Primary System. These states are "vapor", "aerosol", "deposited", and "contained in the core or in corium". These states, and the species of Table 4.7-5, are used to characterize the calculated source term characteristics.

The largest release fractions are calculated for the interfacing LOCA (C63) or V sequence. There is a direct path to the atmosphere with no credit taken for submerged release points or PAB mitigation because of the design of this building.

The second highest radionuclide release fractions are found to occur for the case of the unmitigated SGTR sequence with an unisolated steam generator (SGTR+SORV)(C51). This is because the broken Steam Generator has boiled dry previous to the onset of radionuclide release from the core, so that little mitigation occurs in the secondary system. However, the amount of surface available in the primary and secondary escape path allow some deposition to occur relative to the ISLOCA case.

The third largest releases will occur if the containment fails at or about the time of vessel breach (C65,C67). The in-vessel mitigation processes (deposition) have an effect on reducing the release but there is little time for available for in-containment processes.

The next highest releases would occur for the SGTR without a stuck open relief valve (C57), which terminates when the vessel fails, and the late containment failure case without injection (C61) when a considerable length of time elapses before the containment fails.

Releases are small if there has been successful injection (C62) and/or spray operation (C64), with delayed containment failure.

The release fractions are generally what would be expected. The tellurium releases are smaller than found by analysis using the Source Term Code Package. In the MAAP runs the Te is modelled as being retained in the molten core material while in-vessel which will tend to reduce the releases. The CsOH releases in MAAP calculations almost always mirror the CsI results, whereas in the STCP calculations the CsOH is usually relatively lower. There is also variability in the other non-volatiles reflecting uncertainties and variations in process modeling and rates.

The NUREG-1150 results for the Surry "Late Failure" and "Containment Bypass" modes are compared in Figures 4.7-7 and 4.7-8 (taken from NUREG-1150). Superimposed on these plots are comparable IP-2 MAAP results for C61/C62/C64 and C63/C51/C57, respectively. These are shown as vertical lines with crossed intersections at each of the cases. The bands for the NUREG-1150 release fraction result from the various sequences that were calculated for each class. Reasonably good agreement is shown.

Release fractions calculated with MAAP for the V sequence and for an SBO with an early large containment failure are compared with similar reported cases in Table 4.7-6. The comparison data were taken from NUREG-0956 (Ref. 4.7-1) and were calculated with the Source Term Code Package (STCP), or its components. Further comparison with IPPSS values is given in Table 4.7-7. Agreement is quite good, except for tellurium (due to the modeling differences noted previously), and strontium and barium, where MAAP predicts somewhat higher values for the V sequence.

The bands shown in Figures 4.7-7 and 4.7-8 can be considered as a minimum estimate of the uncertainty in source term calculations. They are mostly two orders of magnitude or more in extent.

The values calculated for the SGTR+SORV are based on IP2 specific calculations using the MAAP code. The values reported here are not inconsistent with other recent studies of similar plants, such as NUREG-1150.

4.7.4 Release Category Frequencies and Dominant Sequences

Twenty six source term release categories were developed for use in grouping the containment sequences. The evaluated frequencies are shown on Figure 4.7-1.

One of the sequence selection criteria in GL 88-20 is any functional sequence that has a core damage frequency greater than or equal to 1E-6 per reactor year and that leads to containment failure which can result in a radioactive release magnitude greater than or equal to the BWR-3 or PWR-4 release categories of WASH-1400. The definitions of these categories is given in Table 5-1 of WASH 1400 which is reproduced in part below. It is seen that PWR-4 is more limiting and will be used here.

Fraction of Core Inventory Released (WASH-1400)

	Xe/ Kr	Org I	Elem I	Cs/ Rb	Te/ Sb	Ba/ Sr	Ru	La
PWR-4	0.6	.003	.09	.04	.03	.05	.003	.004
BWR-3	1.0	.007	.10	.10	.30	.01	.02	.003

For convience and clarity, the various source term classes in this work are classified into the following general release category types:

TYPE I:	I,Cs release fractions >= 0.2
TYPE II:	I,Cs release fractions >= 0.04
TYPE III:	I,Cs release fractions >= 0.002
TYPE IV:	I,Cs release fractions < 0.002
TYPE V:	No containment failure - normal leakage

The above release type ranges were fixed according to the IPE reporting requirements as well as natural breakpoints in the magnitude of the various source terms generated by the analysis.

Types I and II therefore satisfy the GL 88-20 selection criterion of releases equal to or greater than PWR-4 or more.

The source term categories have been assigned to release types using the above classification scheme. The assigned release types are shown on Figure 4.7-7 as the rightmost criterion. The bases for these assignments is shown in Table 4.7-8. Table 4.7-9 lists the source term categories that contribute to TYPE I to TYPE V eleases. The IP2 frequencies (per year) for each release type are shown in Figure 4.7-9 and are listed below.

TYPE I:	3.99E-007 per year
TYPE II:	3.38E-006 "
TYPE III:	1.59E-009 "
TYPE IV:	1.03E-006 "
TYPE V:	2.65E-005 "

Table 4.7-10 lists the plant damage states that contribute to TYPE I and TYPE II release categories at a frequency greater than 10^{-8} per reactor-year.

Table 4.7-11 lists the CET sequences that contribute to Type I to V categories significantly. The CETs for the SGTR+SORV and for Event V are unbranching transfer trees and Sequence 1 is the only sequence on these trees and are perforce the most important paths for Type I. Similarily, there is only one branch on the SGTR w/o SORV CET associated with the Level 1 sequences of this PDS which are the most significant contributor to Type II.

Further discussion of the Level II results is given in Sections 3.4 and 7.

4.7.5 References for Section 4.7

4.7-1 NUREG-0956, "Reassessment of the Technical Bases for Estimating Source Terms", 1986

SECTION 4.8

SENSITIVITY CALCULATIONS

4.8 Sensitivity Calculations

4.8.1 Introduction

An important element of the Level 2 Containment analyses is addressing the question: "To which aspects of the Containment modeling are the overall results most sensitive?" The structured sensitivity analysis presented here aids in the identification of those areas which are most affected by the assumptions or approach used in the analysis. A sensitivity analysis can be represented by the equation:

$$\Delta P_{rc} = f\,(\Delta P_{event})$$

where ΔP_{rc} is the change in an important output (for example the change in the conditional probability of a source term release category)

ΔP_{event} is the change in value of an input to the model (for example, a change in an event split fraction probability), and

f is the functional relationship between the two, defined by the overall backend Containment event analysis.

Important sensitivities can be considered as those where a "reasonable" change in a basic CET (or DET) event probability results in a significant change in the overall results. For example, a change may produce a significant increase (decrease) in the probability of a high source term release category and a corresponding decrease (increase) in a low source term release category. A "reasonable" change in a basic event probability refers to a change that is within the assessed uncertainty range for the event probability.

For phenomenological events, the range of reasonable values to use in a sensitivity analyses is not always evident. These event probabilities can be interpreted as being degrees-of-belief in the outcome of an uncertain event where only one outcome is physically possible but we are not completely certain which is the correct one. Two approaches can be taken for these type events. The first approach acknowledges that either event may be possible and that our probability estimates merely state our belief as to which is most likely to be the correct outcome. For this approach we would set the value of one event branch equal to 1 (and the other branches equal 0) and assess the impact on release category probabilities. This type of approach addresses the question of what the impact on the final results are if this event branch is the correct one for the phenomenological process. We then systematically assign a value of 1 to the other event branch probabilities and repeat the analyses. A second approach to sensitivity analyses for phenomenological events (which is related to assessment of uncertainties) is to investigate the impact of variations in the degree-of-belief probability estimates on the overall results for each of the phenomenological events (i.e., change the assessed probabilities from the baseline values but not necessarily to (1,0), (0,1) combinations discussed above. This approach is analogous to assuming what other experts might select.

The decomposition event trees were reviewed and the phenomenological events which were judged to either have large uncertainties or were expected to have a substantial influence on important outcomes were identified. Sensitivity calculations were performed for most of these phenomenological events. The parameters which were varied in the Level 2 sensitivity study are listed in Table 4.8-1 along with the parameter variations investigated in each case. In all cases the change in the Type I+Type II releases were recorded. For most parameters the sensitivity calculation involved changing one branch probability to one (with all other branch probabilities set to zero) and requantifying the CETs. This was then repeated for each branch. These types of calculations are identified as (1,0) in Table 4.8-1. For several parameters it was more appropriate to use branch probabilities in the sensitivity analysis which were increased/decreased by a multiplicative factor (generally 10) from the base case value.

The principal observations made for the sensitivity studies are presented below.

4.8.2 Results and Observations

The results of the sensitivity runs are reported below. They are given in terms of the change in sequence frequency as a percentage of the base case core damage frequency. For example, in evaluating induced RCS hot leg failure sensitivities (in the following paragraph), the effect of the Case A1 variation was found to change the frequency of arresting the sequence after core damage but before vessel failure from 9.8x10-6/RY to 1.68x10-6/RY. Based on the overall core damage frequency (CDF) of 3.13x10-5/RY, this is a change from 31% of the total core damage events being arrested in vessel in the base case to 4% arrested in vessel following the changes made in the sensitivity analysis. This is shown as (31% -> 5% CDF).

Induced Hot Leg Failure Sensitivities

Sensitivity calculations were performed to assess the impact of assumptions regarding the probability of induced RCS failure on selected important Level 2 results. For this sensitivity calculation the probability for induced RCS failure for "HIGH" and "HI HI" pressure sequences was set equal to 0.0 for Case A1 and to 1.0 for Case A2,respectively. For both cases, the probability of induced SGTR was set to zero.

For Case A1 (no induced RCS failures), there was a significant decrease in the frequency of "debris cooled in-vessel" sequences (31% -> 5% CDF). For case A2 (hot leg failure for all "HIGH" and "HI HI" pressure sequences) there was an increase in the frequency of "debris cooled in-vessel" sequences (31% -> 43% CDF).

There were no significant changes with respect to containment failure for this sensitivity calculation with approximately 85% of the core damage sequences resulting in "No Containment Failure". The frequency of all other Containment failure modes/times changed by 1% or less for this calculation.

For both Cases A1 and A2, the frequency of Type I+II releases decreased slightly (from 12% to 11% CDF), primarily due to the need to set the induced SGTR w/o SORV probability to zero in both cases to properly examine the hot leg failure impact.

Alpha Mode Containment Failure Sensitivities
Loss of Containment Building Isolation Sensitivities

By inspection of the base case results, it can be seen that changing the incidence of these parameters by factors of 10 either way would not have a significant effect on any of the results. This is because of the low frequency of occurrences of these classes.

In-Vessel Debris Cooling Sensitivities

Several events on the Debris Cooled In-vessel DET were included in this sensitivity analysis.

The first sensitivity study was to vary the split fraction for in-vessel cooling when the Injection System is operating for Large LOCAs without functional accumulators. The probability for successful in-vessel cooling was changed to 0.0 (Case C1) and to 1.0 (Case C2). Since the base case probability for successful in-vessel cooling under these conditions was 0.95 the Case C2 results are very similar to the base case. Even when the in-vessel cooling probability was set equal to 0.0 (Case C1) there was less than a 1% change in the frequency of core damage sequences terminated prior to reactor vessel failure. This is because the frequency of core damage events due to Large LOCAs is only about 1% of the total CDF.

The second study varied the in-vessel cooling split fraction for sequences where the Low Pressure Injection System is available but the system pressure is initially too high to allow injection and where system depressurization occurs after core damage has commenced. The probability of successful in-vessel cooling was set equal to zero for Case D1 and was set equal to one for Case D2. As for the Case C1/C2 calculations discussed above the base case value for successful in-vessel cooling is large (.9). Hence the Case D2 results are similar to the base case. Case D1 indicates that the overall frequency of core damage sequences successfully mitigated in-vessel would decrease from 31% to 5% of the CDF if in-vessel cooling is not possible under this specific set of conditions. This is consistent with the results of Case A1.

The third study varied the in-vessel cooling probability for sequences where in-vessel injection is recovered (e.g. power recovery from a station blackout) after core damage has initiated. For Case E1 the probability of successful in-vessel cooling following power recovery (after core damage has been initiated) was set to 0.0 and for Case E2 this probability was set to 1.0. For case E1 the overall frequency of core damage sequences mitigated in-vessel decreased somewhat (31% -> 27% CDF) and increased somewhat for Case E2 (31% -> 33% CDF).

When the core melt termination in-vessel was assumed successful in all situations in which injection was either available or recovered (Case F2 = Cases C2 + D2 + E2), the frequency of core damage sequences arrested in vessel in such cases rose (31% -> 36% CDF). When the core melt could not be terminated in vessel (Case F1 = Cases C1 + D1 + E1), then obviously no sequences were arrested in-vessel.

For both Cases F1 and F2, the Type I+II releases changed less than 1%. This is also true for the other Cases.

Mode of Early Containment Failure Sensitivities

Two sensitivity calculations were performed for the events in the Mode of Early Containment Failure DET, the fraction of mass involved in DCH, and the containment failure pressure. Each of these variations is discussed below.

The importance of the DCH phenomenon to the time of Containment failure was investigated by changing all the DCH events to involve a high percentage (>50%) of the core (Case H1), and then by changing all the DCH events to involve only a small percentage of the core, i.e. less than 10%, (Case H2). The early containment failure category frequency changed less than 1% in either case, staying at about 6-7% of the CDF. This is because the DCH evaluation led to only a small frequency where the Containment was strongly challenged.

A Containment failure pressure sensitivity calculation was made, Case J2, assuming that the containment did not fail if the peak early pressure (on the Early Containment Failure DET) was below 120 psia (105 psig.) The frequency of early and late containment failures were essentially unchanged. This is because most early challenges were of low frequency in any event.

Sensitivity of Recirculation Spray Failure Probability

A sensitivity study was performed to assess the impact of changes in the probability of early (Case K1) or late (Case K2) failure of the Recirculation Sprays due to severe accident physical phenomena and environmental conditions. If the spray was assumed to have failed early (via the RS-Early DET), then the total late containment failure frequencies (Type II and IV) increased slightly (8% -> 10% CDF) and the No Containment Failure class decreased by a like amount. The Type I+II releases increased (12% -> 16% CDF).

No significant effect was noted if the sprays were failed late (Case K2).

A sensitivity study (Case M1) was performed at the PDS level for complete spray failure. The purpose of this study was to bound the importance of the sprays with regard to severe accidents. The PDS diagram was modified such that the recirculation sprays were always failed in every relevant PDS and so always unavailable. Early containment failure frequencies were little affected, but the late failures significantly increased (8% -> 53% CDF). Late Late failures do not occur at all as the containment would always fail late from overpressure. The No Containment Failure sequences decreased (84% -> 40% CDF). The Type I+II releases increased significantly (12% -> 60% CDF).

Clearly the sprays are important to the integrity of the Containment as shown by the results of this hypothetical bounding case.

Sensitivity to Debris Cooled Ex-Vessel

The Debris Cooled Ex-Vessel DET was simplified to force the debris to be "Not Cooled" in every possible situation, as sensitivity Case L1. Late Late Failures (potential basemat meltthroughs) increased noticeably (1% -> 13% CDF), Late Containment Failure type sequences increased slightly (9% -> 10% CDF), and the No Failure class decreased accordingly (84 -> 70% CDF). The Type I+II releases increased slightly (12% -> 13%) because of the increase in the Late Failures.

Frequency of Event-V and of SGTR+SORV

The frequencies of the Event-V (PDS 29) plant damage state and of the SGTR+SORV leading to core damage (PDS 30) are passed through directly to their corresponding release categories (STCs 24 and 26, respectively). These two events are the predominant Type I release contributors and have a frequency ratio of 1:10. That is, a change in the ISLOCA (Event V) frequency of 100% would result in roughly a 10% change in the Type I release frequencies. Beyond this observation, sensitivity calculations were not considered necessary.

Observations

A small increase in the Type I+II release was noted possible if the sprays failed early due to environmental conditions. None of the other sensitivities studied affected the release to any great degree. This is primarily due to the robustness of the containment and the operation of the containment systems. The fraction of sequences arrested in-vessel significantly decreased if there were to be no induced RCS hot leg failures, or if the injection pumps were not recoverable following such failure. However, there was little effect on the Type I and Type II releases.

Although clearly an unrealistic assumption provided for the purpose of bounding only, the significant impact of the sensitivity analysis where sprays are assumed to fail in all cases indicates the importance of the sprays and the reason for their provision in the design. That the containment did not always fail was due to the redundant ability to protect containment by use of the fan coolers.

Rather wide variations in the ISLOCA frequency would not affect the Type I large release very significantly. However, changes in the SGTR + SORV sequence frequencies would be mirrored directly in the Type I release frequencies. It should be noted, however, that while both events are grouped as Type I releases, the SGTR + SORV release magnitudes are approximately a factor of three less than those associated with an ISLOCA.

TABLES FOR SECTION 4

TABLE 4.1-1
Core and Vessel Data

1	Core Full Power	3071.4 MWt
2	Mass of UO_2 in Core	2.22 E5 lb.
3	Mass of Zr in Cladding Surrounding the Core	41,994 lb
4	Mass of Core and Core Support Structures	6.75 E5 lb.
5	Bottom Head Dimensions Inner Radius Thickness (minimum) (not including 7/32in. SS cladding)	 88.5 in. 5 5/16 in.
6	Fuel Enrichment: Region 10 Region 11 Region 12	 3.2 - 3.4 w/o 3.4 - 3.7 w/o 3.6 - 4.2 w/o
7	Control Rod Assembly Constituent Data: Total Weight per Assembly Weight %'s: Cadmium (Cd) Indium (In) Silver (Ag)	 107 lb 5% 15% 80%

TABLE 4.1-2
Primary System Data

1	Primary Water (Full Power Conditions): Inventory Temperature (Hot Zero Power) Pressure Enthalpy	 12250 ft^3 547 °F 2235 psig 3.04 E8 Btu
2	Secondary Side Fluid Volumes: Water Volume Steam Volume	 1613 ft^3 2966 ft^3
3	Steam Generator Data: No. of Generators Manufacturer Type Model	 4 Westinghouse U - Tube 44
4	Primary System Flow Rate	1.34 E8 lbs/hr
5	Pressurizer Fluid Volumes (Full Power Conditions): Water Volume Steam Volume	 1080 ft^3 720 ft^3
6	Power Operated Relief Valve Data: Number Capacity/Valve (saturated steam) Setting	 2 1.79 E5 lb/hr 2335 psig
7	Pressurizer Safety Valve Data: Number Capacity/Valve (saturated steam) Settings	 3 4.08 E5 lb/hr 2485 psig
8	Accumulator Data: Number of Tanks Inventory of Water Initiating Pressure	 4 795 ft^3 each 630 psia

TABLE 4.1-2 Containment Systems Data (continued)

4	Interior Structural Heat Sinks:		
	Location	Materials	Surface Area (ft^2)
	a)Dome	Paint/Steel/Concrete	28,613
	b)Upper Wall	"	45,684
	c)Middle Wall	"	8,178
	d)Lower Wall	"	7,634
	e)Floor	Concrete	15,000
	f)Refueling Cavity	Steel/Concrete	10,000
	g)Miscellaneous Concrete	Concrete	61,000
	h)Crane & Tanks	Steel	68,792
	i)Framing and Supports	Paint/Steel	151,504
	j)Piping	Steel	27,948
	k)Ductwork	"	22,000
	l)Conduit	"	3,000
	m)Misc. Metal	"	10,000

TABLE 4.1-3
Containment Systems Data

1	Containment Structure: Type Free Volume Design Pressure Normal Operating Pressure Normal Temperature Reactor Cavity Floor Area Liner Thickness Wall Thickness Basemat Thickness	 Large, Dry, Reinforced Concrete 2.61 E6 ft^3 47 psig Atmospheric (0-2 psig) +50°F to 130°F 989 ft^2 See Written Discussion
2	Containment Mitigation System - Containment Spray Number of Pumps Design Flow Rate Spray Initiation Setpoint Spray Additive Solution	 2 2600 gpm per pump 28 psig 33% (minimum) NaOH
3	Containment Mitigation System - Fan Cooler Units Number of Fans Total Cooling Capacity Flow Rate Per Fan	 5 3.085 E8 Btu/hr with a 95°F River Water Temperature 65,000 cfm

TABLE 4.6-1

AGGREGATE RESULTS FROM NUREG/CR-4551 PRESSURE RISE AT VESSEL BREACH AT ZION (PSIG)

Case	RCS Pressure[a]	Cavity Water	Sprays Operating	Core Fraction Ejected[b]	Vessel Hole Size[c]	Fractile 0.05	Fractile 0.50	Fractile 0.95
1	High	Full	Yes	High	Large	32.05	81.42	127.89
2	High	Full	Yes	High	Small	28.35	73.08	116.73
3	High	Full	Yes	Medium	Large	29.43	65.98	101.06
4	High	Full	Yes	Medium	Small	26.39	58.73	93.24
5	High	Full	Yes	Low	Large	20.16	45.68	74.75
6	High	Full	Yes	Low	Small	18.63	42.05	70.83
7	High	Half/Dry	No	High	Large	38.28	89.54	127.09
8	High	Half/Dry	No	High	Small	33.28	81.42	114.41
9	High	Half/Dry	No	Medium	Large	35.24	72.06	105.27
10	High	Half/Dry	No	Medium	Small	29.43	65.40	94.54
11	High	Half/Dry	No	Low	Large	23.06	48.72	76.85
12	High	Half/Dry	No	Low	Small	20.16	45.39	71.49
13	Medium	Full	Yes	High	Large	26.10	65.03	98.75
14	Medium	Full	Yes	High	Small	21.17	55.17	90.19
15	Medium	Full	Yes	Medium	Large	23.64	52.93	79.46
16	Medium	Full	Yes	Medium	Small	18.13	45.39	68.58
17	Medium	Full	Yes	Low	Large	17.26	39.15	63.94
18	Medium	Full	Yes	Low	Small	14.50	35.38	58.51
19	Medium	Half/Dry	No	High	Large	33.13	72.57	102.08
20	Medium	Half/Dry	No	High	Small	27.19	61.63	93.89
21	Medium	Half/Dry	No	Medium	Large	30.01	58.29	80.91
22	Medium	Half/Dry	No	Medium	Small	24.22	50.46	74.82
23	Medium	Half/Dry	No	Low	Large	20.44	41.83	64.67
24	Medium	Half/Dry	No	Low	Small	17.55	37.92	61.63
25	Low	-	-	-	-	10.88	25.38	48.43

[a] RCS Pressure: High = 2000 to 2500 psi
Medium = 500 to 1000 psi
Low = 50 to 200 psi

[b] Core Fraction Ejected: High = 40 to 60 %
Medium = 20 to 40 %
Low = 0 to 20 %

[c] Vessel Hole Size: Large = 2 m^2
Small = 0.1 m^2

TABLE 4.6-2

PEAK CONTAINMENT PRESSURES BASED ON RESULTS EXTRACTED FROM NUREG/CR-4551

DET Endpoint Number	NUREG/CR-4551 Table 7.3 Case Number	Containment Pressure psig (psia)
1 - 2	1	82[a] + 0[b] = 82 (97)
3	3	66 + 0 = 66 (81)
4	5	46 + 0 = 46 (61)
5 - 7	7	90 + 0 = 90 (105)
8 - 9	9	72 + 0 = 72 (87)
10	11	49 + 0 = 49 (64)
12	13	65 + 0 = 65 (80)
13	15	53 + 0 = 53 (68)
14	17	39 + 0 = 39 (54)
15 - 16	19	73 + 0 = 73 (88)
17	21	58 + 0 = 58 (73)
18	23	42 + 0 = 42 (57)
20	25	25 + 0 = 25 (40)
22 - 24	1	82 + 13 = 95 (110)
25 - 26	3	66 + 13 = 79 (94)
27	5	46 + 13 = 59 (74)
28 - 30	7	90 + 13 = 103 (118)
31 - 33	9	72 + 13 = 85 (100)
34	11	49 + 13 = 62 (77)
36 - 37	13	65 + 13 = 78 (93)
38	15	53 + 13 = 66 (81)
39	17	39 + 13 = 52 (67)
40 - 42	19	73 + 13 = 86 (101)
43 - 44	21	58 + 13 = 71 (86)
45	23	42 + 13 = 55 (70)
47	25	25 + 13 = 38 (53)
49 - 51	1	82 + 22 = 104 (119)
52 - 54	3	66 + 22 = 88 (103)
55	5	46 + 22 = 68 (83)
56 - 58	7	90 + 22 = 112 (127)
59 - 61	9	72 + 22 = 94 (109)
62	11	49 + 22 = 71 (86)
64 - 66	13	65 + 22 = 87 (102)
67 - 68	15	53 + 22 = 75 (90)
69	17	39 + 22 = 61 (76)
70 - 72	19	73 + 22 = 95 (110)
73 - 74	21	58 + 22 = 80 (95)
75	23	42 + 22 = 64 (79)
77	25	25 + 22 = 47 (62)

Notes:

a)The 50^{th} percentile values from Table 4.6-1 are used to calculate the pressure rise. Also, a large vessel hole size is assumed.

b)The containment pressure at RV failure (from Event 4 of this DET) is added to the pressure rise.

TABLE 4.6-3

DISCRETIZED CONTAINMENT FRAGILITY CURVE

PSIG	PSIA	PF	CLEAK	CRUPT	CCATRP	PNOF	PLEAK	PRUPT	PCATRP
70	85	0.000	1.000	0.000	0.000	1.000	0.000	0.000	0.000
71	86	0.000	0.990	0.010	0.000	1.000	0.000	0.000	0.000
72	87	0.001	0.980	0.020	0.000	0.999	0.001	0.000	0.000
73	88	0.001	0.970	0.030	0.000	0.999	0.001	0.000	0.000
74	89	0.002	0.960	0.040	0.000	0.998	0.002	0.000	0.000
75	90	0.002	0.950	0.050	0.000	0.998	0.002	0.000	0.000
76	91	0.004	0.953	0.047	0.000	0.996	0.003	0.000	0.000
77	92	0.005	0.957	0.043	0.000	0.995	0.005	0.000	0.000
78	93	0.007	0.960	0.040	0.000	0.993	0.007	0.000	0.000
79	94	0.008	0.964	0.046	0.000	0.992	0.008	0.000	0.000
80	95	0.010	0.967	0.033	0.000	0.990	0.010	0.000	0.000
81	96	0.012	0.966	0.034	0.000	0.988	0.012	0.000	0.000
82	97	0.014	0.965	0.035	0.000	0.986	0.014	0.000	0.000
83	98	0.016	0.965	0.035	0.000	0.984	0.015	0.001	0.000
84	99	0.018	0.964	0.036	0.000	0.982	0.017	0.001	0.000
85	100	0.020	0.963	0.037	0.000	0.980	0.019	0.001	0.000
86	101	0.022	0.953	0.047	0.000	0.978	0.021	0.001	0.000
87	102	0.024	0.942	0.058	0.000	0.976	0.023	0.001	0.000
88	103	0.027	0.932	0.068	0.000	0.973	0.025	0.002	0.000
89	104	0.029	0.921	0.079	0.000	0.971	0.027	0.002	0.000
90	105	0.031	0.911	0.089	0.000	0.969	0.028	0.003	0.000
91	106	0.037	0.903	0.097	0.000	0.963	0.033	0.004	0.000
92	107	0.042	0.896	0.104	0.000	0.958	0.038	0.004	0.000
93	108	0.048	0.888	0.112	0.000	0.952	0.042	0.005	0.000
94	109	0.053	0.881	0.119	0.000	0.947	0.047	0.006	0.000
95	110	0.059	0.873	0.127	0.000	0.941	0.052	0.007	0.000
96	111	0.066	0.873	0.127	0.000	0.934	0.058	0.008	0.000
97	112	0.073	0.872	0.128	0.000	0.927	0.064	0.009	0.000
98	113	0.081	0.872	0.128	0.000	0.919	0.070	0.010	0.000
99	114	0.088	0.871	0.129	0.000	0.912	0.077	0.011	0.000
100	115	0.095	0.871	0.129	0.000	0.905	0.083	0.012	0.000
101	116	0.104	0.872	0.128	0.000	0.896	0.090	0.013	0.000
102	117	0.112	0.873	0.127	0.000	0.888	0.098	0.014	0.000
103	118	0.121	0.874	0.126	0.000	0.879	0.106	0.015	0.000
104	119	0.129	0.875	0.125	0.000	0.871	0.113	0.016	0.000
105	120	0.138	0.876	0.124	0.000	0.862	0.121	0.017	0.000

TABLE 4.6-3 (Continued)

DISCRETIZED CONTAINMENT FRAGILITY CURVE

PSIG	PSIA	PF	CLEAK	CRUPT	CCATRP	PNOF	PLEAK	PRUPT	PCATRP
106	121	0.152	0.882	0.118	0.000	0.848	0.134	0.018	0.000
107	122	0.166	0.888	0.112	0.000	0.834	0.147	0.019	0.000
108	123	0.180	0.893	0.107	0.000	0.820	0.161	0.019	0.000
109	124	0.194	0.899	0.101	0.000	0.806	0.174	0.020	0.000
110	125	0.208	0.905	0.095	0.000	0.792	0.188	0.020	0.000
111	126	0.229	0.910	0.090	0.000	0.771	0.209	0.021	0.000
112	127	0.251	0.916	0.084	0.000	0.749	0.230	0.021	0.000
113	128	0.272	0.921	0.079	0.000	0.728	0.251	0.021	0.000
114	129	0.294	0.927	0.073	0.000	0.706	0.272	0.022	0.000
115	130	0.315	0.932	0.068	0.000	0.685	0.294	0.021	0.000
116	131	0.325	0.910	0.090	0.000	0.675	0.296	0.029	0.000
117	132	0.335	0.887	0.113	0.000	0.665	0.297	0.038	0.000
118	133	0.345	0.865	0.135	0.000	0.655	0.298	0.047	0.000
119	134	0.355	0.842	0.158	0.000	0.645	0.299	0.056	0.000
120	135	0.365	0.820	0.180	0.000	0.635	0.299	0.066	0.000
121	136	0.381	0.794	0.203	0.003	0.619	0.303	0.077	0.001
122	137	0.397	0.769	0.226	0.005	0.603	0.306	0.090	0.002
123	138	0.414	0.743	0.250	0.008	0.586	0.307	0.103	0.003
124	139	0.430	0.718	0.273	0.010	0.570	0.308	0.117	0.004
125	140	0.446	0.692	0.296	0.013	0.554	0.309	0.132	0.006
126	141	0.463	0.662	0.323	0.015	0.537	0.307	0.150	0.007
127	142	0.480	0.633	0.350	0.017	0.520	0.303	0.168	0.008
128	143	0.496	0.603	0.378	0.020	0.504	0.299	0.187	0.010
129	144	0.513	0.574	0.405	0.022	0.487	0.294	0.208	0.011
130	145	0.530	0.544	0.432	0.024	0.470	0.288	0.229	0.013
131	146	0.547	0.516	0.458	0.026	0.453	0.282	0.250	0.014
132	147	0.563	0.488	0.484	0.028	0.437	0.275	0.273	0.016
133	148	0.580	0.461	0.510	0.029	0.420	0.267	0.296	0.017
134	149	0.596	0.433	0.536	0.031	0.404	0.258	0.320	0.019
135	150	0.613	0.405	0.562	0.033	0.387	0.248	0.345	0.020
136	151	0.639	0.421	0.538	0.041	0.361	0.269	0.344	0.026
137	152	0.665	0.437	0.515	0.048	0.335	0.291	0.342	0.032
138	153	0.691	0.453	0.491	0.056	0.309	0.313	0.339	0.039
139	154	0.717	0.469	0.468	0.063	0.283	0.336	0.335	0.045
140	155	0.743	0.485	0.444	0.071	0.257	0.360	0.330	0.053

Table 4.6-3 (Continued)

DISCRETIZED CONTAINMENT FRAGILITY CURVE

PSIG	PSIA	PF	CLEAK	CRUPT	CCATRP	PNOF	PLEAK	PRUPT	PCATRP
141	156	0.767	0.455	0.448	0.096	0.233	0.349	0.344	0.074
142	157	0.791	0.425	0.453	0.122	0.209	0.336	0.358	0.096
143	158	0.815	0.396	0.457	0.147	0.185	0.322	0.373	0.120
144	159	0.839	0.366	0.462	0.173	0.161	0.307	0.387	0.145
145	160	0.863	0.336	0.466	0.198	0.137	0.290	0.402	0.171
146	161	0.883	0.317	0.456	0.227	0.117	0.280	0.403	0.200
147	162	0.903	0.298	0.447	0.256	0.097	0.269	0.403	0.231
148	163	0.923	0.278	0.437	0.285	0.077	0.257	0.404	0.263
149	164	0.943	0.259	0.428	0.314	0.057	0.244	0.403	0.296
150	165	0.963	0.240	0.418	0.343	0.037	0.231	0.403	0.330
151	166	0.968	0.235	0.402	0.363	0.032	0.227	0.389	0.352
152	167	0.972	0.230	0.387	0.384	0.028	0.223	0.376	0.373
153	168	0.977	0.224	0.371	0.404	0.023	0.219	0.363	0.395
154	169	0.981	0.219	0.356	0.425	0.019	0.215	0.349	0.417
155	170	0.986	0.214	0.340	0.445	0.014	0.211	0.335	0.439
156	171	0.987	0.172	0.325	0.503	0.013	0.169	0.320	0.497
157	172	0.988	0.129	0.309	0.561	0.012	0.128	0.306	0.554
158	173	0.990	0.087	0.294	0.619	0.010	0.086	0.291	0.613
159	174	0.991	0.044	0.278	0.677	0.009	0.044	0.276	0.671
160	175	0.992	0.002	0.263	0.735	0.008	0.002	0.261	0.729
161	176	0.993	0.002	0.259	0.739	0.007	0.002	0.257	0.734
162	177	0.994	0.001	0.255	0.744	0.006	0.001	0.253	0.739
163	178	0.995	0.001	0.251	0.748	0.005	0.001	0.250	0.744
164	179	0.996	0.000	0.247	0.753	0.004	0.000	0.246	0.750
165	180	0.997	0.000	0.243	0.757	0.003	0.000	0.242	0.755
166	181	0.997	0.000	0.194	0.806	0.003	0.000	0.194	0.803
167	182	0.997	0.000	0.146	0.854	0.003	0.000	0.145	0.852
168	183	0.998	0.000	0.097	0.903	0.002	0.000	0.097	0.901
169	184	0.998	0.000	0.049	0.951	0.002	0.000	0.048	0.949
170	185	0.998	0.000	0.000	1.000	0.002	0.000	0.000	0.998

TABLE 4.6-3 (Continued)

DISCRETIZED CONTAINMENT FRAGILITY CURVE

PSIG	PSIA	PF	CLEAK	CRUPT	CCATRP	PNOF	PLEAK	PRUPT	PCATRP
171	186	0.998	0.000	0.000	1.000	0.002	0.000	0.000	0.998
172	187	0.998	0.000	0.000	1.000	0.002	0.000	0.000	0.998
173	188	0.999	0.000	0.000	1.000	0.001	0.000	0.000	0.999
174	189	0.999	0.000	0.000	1.000	0.001	0.000	0.000	0.999
175	190	0.999	0.000	0.000	1.000	0.001	0.000	0.000	0.999
176	191	0.999	0.000	0.000	1.000	0.001	0.000	0.000	0.999

PSIG = Containment pressure - gauge
PSIA = Containment pressure - absolute
PF = Cumulative probability of Containment Failure
PNOF = 1 - PF
CLEAK = Conditional probability of leak type failure (conditional on failure)
CRUPT = Conditional probability of rupture type failure
CCATRP = Conditional probability of catastrophic rupture type failure
PLEAK = PF x CLEAK = Absolute probability of leak type failure (conditional on failure)
PRUPT = PF x CRUPT = Absolute probability of rupture type failure
PCATRP = PF x CCATRP = Absolute probability of catastrophic rupture type failure

TABLE 4.7-1:
IMPORTANCE OF PLANT DAMAGE STATES TO RELEASE CATEGORIES

	Amount	Percent
Source Term Category: 1	**1.672E-005**	
PDS27	5.066E-006	30.302
PDS11	4.010E-006	23.984
PDS24	1.799E-006	10.761
PDS2	1.407E-006	8.412
PDS25	1.386E-006	8.289
PDS23	5.557E-007	3.324
PDS19	5.352E-007	3.201
PDS1	5.332E-007	3.189
PDS12	4.968E-007	2.971
PDS6	2.144E-007	1.283
PDS17	1.764E-007	1.055
Source Term Category: 2	**2.145E-008**	
	Amount	Percent
PDS13	8.324E-009	38.808
PDS6	6.837E-009	31.876
PDS11	2.856E-009	13.314
PDS7	1.993E-009	9.291
PDS8	4.359E-010	2.032
PDS1	3.884E-010	1.811
PDS12	3.506E-010	1.635
Source Term Category: 3	**1.687E-009**	
	Amount	Percent
PDS6	7.548E-010	44.742
PDS13	7.064E-010	41.872
PDS7	1.715E-010	10.163
PDS8	4.392E-011	2.603
Source Term Category: 4	**1.003E-009**	
	Amount	Percent
PDS13	9.252E-010	92.239
PDS8	4.845E-011	4.831
PDS14	2.243E-011	2.236
Source Term Category: 5	**8.454E-011**	
	Amount	Percent
PDS13	7.850E-011	92.853
PDS8	4.881E-012	5.774
PDS14	1.161E-012	1.373

Note: PDS #s in this table correspond to the Level 2 designation (see section 3.1.6)

TABLE 4.7-1 (Continued):
IMPORTANCE OF PLANT DAMAGE STATES TO RELEASE CATEGORIES

	Amount	Percent
Source Term Category: 6	**3.213E-011**	
	Amount	Percent
PDS7	1.691E-011	52.625
PDS6	9.099E-012	28.319
PDS8	6.123E-012	19.057
Source Term Category: 7	**1.636E-011**	
	Amount	Percent
PDS6	7.996E-012	48.876
PDS8	5.381E-012	32.890
PDS7	2.983E-012	18.234
Source Term Category: 8	**1.535E-008**	
	Amount	Percent
PDS9	7.450E-009	48.533
PDS20	4.466E-009	29.093
PDS28	8.972E-010	5.845
PDS21	8.188E-010	5.334
PDS5	4.507E-010	2.936
PDS17	3.575E-010	2.329
PDS27	2.779E-010	1.810
PDS10	2.034E-010	1.325
Source Term Category: 9	**1.615E-009**	
	Amount	Percent
PDS9	8.311E-010	51.463
PDS20	4.982E-010	30.850
PDS13	9.297E-011	5.757
PDS21	7.114E-011	4.405
PDS5	3.557E-011	2.203
PDS28	2.894E-011	1.792
PDS17	2.821E-011	1.747
Source Term Category: 10	**3.887E-007**	
	Amount	Percent
PDS13	3.122E-007	80.331
PDS3	4.967E-008	12.779
PDS14	1.413E-008	3.634
PDS8	8.352E-009	2.149
PDS15	4.305E-009	1.108

Note: PDS #s in this table correspond to the Level 2 designation (see section 3.1.6)

TABLE 4.7-1 (Continued):
IMPORTANCE OF PLANT DAMAGE STATES TO RELEASE CATEGORIES

Source Term Category: 11	**2.248E-007**	
	Amount	Percent
PDS13	1.808E-007	80.417
PDS3	2.876E-008	12.792
PDS14	8.179E-009	3.638
PDS8	4.593E-009	2.043
PDS15	2.493E-009	1.109
Source Term Category: 12	**4.463E-008**	
	Amount	Percent
PDS13	3.585E-008	80.331
PDS3	5.703E-009	12.778
PDS14	1.622E-009	3.634
PDS8	9.590E-010	2.149
PDS15	4.943E-010	1.108
Source Term Category: 13	**4.502E-008**	
	Amount	Percent
PDS13	3.620E-008	80.418
PDS3	5.759E-009	12.792
PDS14	1.638E-009	3.638
PDS8	9.198E-010	2.043
PDS15	4.992E-010	1.109
Source Term Category: 14	**1.008E-009**	
	Amount	Percent
PDS7	5.466E-010	54.225
PDS6	2.687E-010	26.655
PDS8	1.927E-010	19.120
Source Term Category: 15	**5.835E-010**	
	Amount	Percent
PDS7	3.164E-010	54.228
PDS6	1.555E-010	26.653
PDS8	1.116E-010	19.119

Note: PDS #s in this table correspond to the Level 2 designation (see section 3.1.6)

TABLE 4.7-1 (Continued):
IMPORTANCE OF PLANT DAMAGE STATES TO RELEASE CATEGORIES

Source Term Category: 16 1.098E-006

	Amount	Percent
PDS28	2.851E-007	25.964
PDS27	2.742E-007	24.970
PDS9	1.418E-007	12.914
PDS5	1.381E-007	12.574
PDS20	8.500E-008	7.741
PDS10	6.462E-008	5.885
PDS19	2.896E-008	2.638
PDS21	2.585E-008	2.354
PDS11	1.590E-008	1.448

Note: PDS #s in this table correspond to the Level 2 designation (see section 3.1.6)

TABLE 4.7-1 (Continued):
IMPORTANCE OF PLANT DAMAGE STATES TO RELEASE CATEGORIES

Source Term Category: 17	6.846E-007	
	Amount	Percent
PDS28	1.777E-007	25.962
PDS27	1.709E-007	24.967
PDS9	8.841E-008	12.914
PDS5	8.607E-008	12.573
PDS20	5.300E-008	7.741
PDS10	4.028E-008	5.884
PDS19	1.806E-008	2.638
PDS21	1.612E-008	2.355
PDS11	9.913E-009	1.448
Source Term Category: 18	**3.241E-007**	
	Amount	Percent
PDS24	9.469E-008	29.217
PDS11	7.438E-008	22.948
PDS27	4.715E-008	14.549
PDS23	2.925E-008	9.024
PDS1	2.177E-008	6.718
PDS2	1.335E-008	4.121
PDS25	1.316E-008	4.060
PDS6	8.712E-009	2.688
PDS17	7.308E-009	2.255
PDS19	4.982E-009	1.537
PDS12	4.790E-009	1.478
Source Term Category: 19	**4.892E-009**	
	Amount	Percent
PDS11	2.057E-009	42.051
PDS2	7.159E-010	14.634
PDS25	7.054E-010	14.420
PDS13	3.108E-010	6.352
PDS23	2.926E-010	5.981
PDS1	2.784E-010	5.690
PDS12	2.531E-010	5.173
PDS6	1.157E-010	2.364
PDS7	6.499E-011	1.329

Note: PDS #s in this table correspond to the Level 2 designation (see section 3.1.6)

TABLE 4.7-1 (Continued):
IMPORTANCE OF PLANT DAMAGE STATES TO RELEASE CATEGORIES

Source Term Category: 20 4.899E-009

	Amount	Percent
PDS27	2.781E-009	56.772
PDS24	9.476E-010	19.342
PDS19	2.938E-010	5.998
PDS28	2.897E-010	5.913
PDS9	1.259E-010	2.570
PDS5	1.187E-010	2.423
PDS17	9.413E-011	1.921
PDS20	7.547E-011	1.541
PDS10	6.566E-011	1.340

Source Term Category: 21 1.682E-010

	Amount	Percent
PDS24	7.576E-011	45.039
PDS23	2.340E-011	13.911
PDS27	2.224E-011	13.219
PDS11	1.645E-011	9.778
PDS2	5.725E-012	3.403
PDS25	5.641E-012	3.354
PDS13	2.485E-012	1.477
PDS19	2.349E-012	1.397
PDS28	2.316E-012	1.377
PDS1	2.226E-012	1.324
PDS12	2.024E-012	1.203

Source Term Category: 22 9.795E-006

	Amount	Percent
PDS11	7.979E-006	81.458
PDS1	1.298E-006	13.257
PDS22	3.593E-007	3.668
PDS16	1.425E-007	1.455

Source Term Category: 23 4.900E-009

	Amount	Percent
PDS11	3.991E-009	81.458
PDS1	6.496E-010	13.256
PDS22	1.797E-010	3.668
PDS16	7.128E-011	1.455

Note: PDS #s in this table correspond to the Level 2 designation (see section 3.1.6)

TABLE 4.7-1 (Continued):
IMPORTANCE OF PLANT DAMAGE STATES TO RELEASE CATEGORIES

Source Term Category: 24	**2.672E-008**	
	Amount	Percent
PDS29	2.672E-008	100.000
Source Term Category: 25	**1.543E-006**	
	Amount	Percent
PDS30	1.250E-006	81.030
PDS11	2.218E-007	14.375
PDS1	3.403E-008	2.205
Source Term Category: 26	**3.725E-007**	
	Amount	Percent
PDS31	3.725E-007	100.000

Note: PDS #s in this table correspond to the Level 2 designation (see section 3.1.6)

TABLE 4.7-2:
IMPORTANCE OF CONTAINMENT SEQUENCES TO RELEASE CATEGORIES

Source Term Category: 1 1.672E-005

	Amount	Percent
Seq 11 of CET 27	4.815E-006	28.8
Seq 1 of CET 11	3.071E-006	18.4
Seq 11 of CET 24	1.515E-006	9.1
Seq 1 of CET 2	1.363E-006	8.2
Seq 1 of CET 25	1.344E-006	8.0
Seq 58 of CET 11	7.088E-007	4.2
Seq 11 of CET 19	5.086E-007	3.0
Seq 1 of CET 12	4.800E-007	2.9
Seq 1 of CET 23	4.680E-007	2.8
Seq 58 of CET 1	3.262E-007	2.0
Seq 12 of CET 24	2.841E-007	1.7

Source Term Category: 2 2.145E-008

	Amount	Percent
Seq 84 of CET 13	7.437E-009	34.7
Seq 78 of CET 6	4.746E-009	22.1
Seq 21 of CET 11	2.151E-009	10.0
Seq 21 of CET 7	1.770E-009	8.3
Seq 80 of CET 6	1.187E-009	5.5
Seq 21 of CET 6	8.698E-010	4.1
Seq 27 of CET 13	7.096E-010	3.3
Seq 78 of CET 11	4.964E-010	2.3
Seq 84 of CET 8	3.829E-010	1.8
Seq 21 of CET 12	3.362E-010	1.6
Seq 78 of CET 1	2.284E-010	1.1

Source Term Category: 3 1.687E-009

	Amount	Percent
Seq100 of CET 13	6.642E-010	39.4
Seq 94 of CET 6	5.434E-010	32.2
Seq 37 of CET 7	1.480E-010	8.8
Seq 96 of CET 6	1.359E-010	8.1
Seq 37 of CET 6	7.273E-011	4.3
Seq100 of CET 8	3.990E-011	2.4
Seq 43 of CET 13	3.387E-011	2.0

TABLE 4.7-2 (Continued):
IMPORTANCE OF CONTAINMENT SEQUENCES TO RELEASE CATEGORIES

Source Term Category: 4	1.003E-009	
	Amount	Percent
Seq 85 of CET 13	8.263E-010	82.4
Seq 28 of CET 13	7.884E-011	7.9
Seq 85 of CET 8	4.255E-011	4.2
Seq 26 of CET 13	1.962E-011	2.0
Seq 28 of CET 14	1.621E-011	1.6
Source Term Category: 5	**8.454E-011**	
	Amount	Percent
Seq101 of CET 13	7.380E-011	87.3
Seq101 of CET 8	4.434E-012	5.2
Seq 44 of CET 13	3.763E-012	4.5
Seq 42 of CET 13	9.364E-013	1.1
Source Term Category: 6	**3.213E-011**	
	Amount	Percent
Seq 35 of CET 7	1.352E-011	42.1
Seq 35 of CET 6	6.646E-012	20.7
Seq 35 of CET 8	4.721E-012	14.7
Seq 33 of CET 7	3.365E-012	10.5
Seq 33 of CET 6	1.654E-012	5.1
Seq 33 of CET 8	1.175E-012	3.7
Seq 92 of CET 6	8.011E-013	2.5
Source Term Category: 7	**1.636E-011**	
	Amount	Percent
Seq108 of CET 6	6.612E-012	40.4
Seq108 of CET 8	4.434E-012	27.1
Seq 51 of CET 7	2.250E-012	13.8
Seq 51 of CET 6	1.106E-012	6.8
Seq 51 of CET 8	7.576E-013	4.6
Seq 49 of CET 7	5.599E-013	3.4
Seq 49 of CET 6	2.752E-013	1.7
Seq 49 of CET 8	1.885E-013	1.2
Seq108 of CET 7	1.723E-013	1.1

TABLE 4.7-2 (Continued):
IMPORTANCE OF CONTAINMENT SEQUENCES TO RELEASE CATEGORIES

Source Term Category: 8 1.535E-008

	Amount	Percent
Seq 93 of CET 9	6.458E-009	42.1
Seq 93 of CET 20	3.871E-009	25.2
Seq 36 of CET 9	7.956E-010	5.2
Seq 36 of CET 28	7.186E-010	4.7
Seq 36 of CET 21	6.053E-010	3.9
Seq 36 of CET 20	4.770E-010	3.1
Seq 93 of CET 5	3.305E-010	2.2
Seq 30 of CET 27	2.407E-010	1.6
Seq 87 of CET 17	2.096E-010	1.4
Seq 34 of CET 9	1.980E-010	1.3
Seq 34 of CET 28	1.788E-010	1.2
Seq 36 of CET 10	1.629E-010	1.1
Seq 34 of CET 21	1.506E-010	1.0

Source Term Category: 9 1.615E-009

	Amount	Percent
Seq109 of CET 9	7.472E-010	46.3
Seq109 of CET 20	4.480E-010	27.7
Seq109 of CET 13	8.200E-011	5.1
Seq 52 of CET 9	6.720E-011	4.2
Seq 52 of CET 21	5.112E-011	3.2
Seq 52 of CET 20	4.029E-011	2.5
Seq109 of CET 5	2.610E-011	1.6
Seq 52 of CET 28	2.318E-011	1.4
Seq 50 of CET 9	1.672E-011	1.0

Source Term Category: 10 3.887E-007

	Amount	Percent
Seq 62 of CET 13	2.467E-007	63.5
Seq 5 of CET 13	6.555E-008	16.9
Seq 62 of CET 3	3.935E-008	10.1
Seq 5 of CET 14	1.348E-008	3.5
Seq 5 of CET 3	1.032E-008	2.7
Seq 62 of CET 8	6.620E-009	1.7
Seq 5 of CET 15	4.305E-009	1.1

TABLE 4.7-2 (Continued):
IMPORTANCE OF CONTAINMENT SEQUENCES TO RELEASE CATEGORIES

Source Term Category: 11 2.248E-007

	Amount	Percent
Seq 64 of CET 13	1.212E-007	53.9
Seq 7 of CET 13	3.220E-008	14.3
Seq 66 of CET 13	2.166E-008	9.6
Seq 64 of CET 3	1.933E-008	8.6

Source Term Category: 12 4.463E-008

	Amount	Percent
Seq 63 of CET 13	2.833E-008	63.5
Seq 6 of CET 13	7.527E-009	16.9
Seq 63 of CET 3	4.519E-009	10.1
Seq 6 of CET 14	1.548E-009	3.5
Seq 6 of CET 3	1.185E-009	2.7
Seq 63 of CET 8	7.601E-010	1.7
Seq 6 of CET 15	4.943E-010	1.1

Source Term Category: 13 4.502E-008

	Amount	Percent
Seq 65 of CET 13	1.544E-008	34.3
Seq 67 of CET 13	1.316E-008	29.2
Seq 8 of CET 13	4.102E-009	9.1
Seq 10 of CET 13	3.498E-009	7.8
Seq 65 of CET 3	2.463E-009	5.5
Seq 67 of CET 3	2.100E-009	4.7
Seq 8 of CET 14	8.434E-010	1.9
Seq 10 of CET 14	7.192E-010	1.6
Seq 8 of CET 3	6.458E-010	1.4
Seq 10 of CET 3	5.507E-010	1.2

Source Term Category: 14 1.008E-009

	Amount	Percent
Seq 15 of CET 7	5.464E-010	54.2
Seq 15 of CET 6	2.686E-010	26.7
Seq 15 of CET 8	1.927E-010	19.1

Source Term Category: 15 5.835E-010

	Amount	Percent
Seq 17 of CET 7	2.684E-010	46.0
Seq 17 of CET 6	1.319E-010	22.6
Seq 17 of CET 8	9.466E-011	16.2
Seq 19 of CET 7	4.798E-011	8.2
Seq 19 of CET 6	2.358E-011	4.0
Seq 19 of CET 8	1.692E-011	2.9

TABLE 4.7-2 (Continued): IMPORTANCE OF CONTAINMENT SEQUENCES TO RELEASE CATEGORIES

Source Term Category: 16 1.098E-006

	Amount	Percent
Seq 16 of CET 28	2.851E-007	26.0
Seq 16 of CET 27	2.742E-007	25.0
Seq 73 of CET 9	1.092E-007	9.9
Seq 73 of CET 5	1.069E-007	9.7
Seq 73 of CET 20	6.547E-008	6.0
Seq 16 of CET 10	6.463E-008	5.9
Seq 16 of CET 9	3.258E-008	3.0
Seq 16 of CET 5	3.116E-008	2.8
Seq 16 of CET 19	2.897E-008	2.6
Seq 16 of CET 21	2.479E-008	2.3
Seq 16 of CET 20	1.953E-008	1.8
Seq 16 of CET 11	1.590E-008	1.4

Source Term Category: 17 6.846E-007

	Amount	Percent
Seq 18 of CET 28	1.416E-007	20.7
Seq 18 of CET 27	1.362E-007	19.9
Seq 75 of CET 9	5.425E-008	7.9
Seq 75 of CET 5	5.313E-008	7.8
Seq 20 of CET 28	3.610E-008	5.3
Seq 20 of CET 27	3.472E-008	5.1
Seq 75 of CET 20	3.252E-008	4.8
Seq 18 of CET 10	3.210E-008	4.7
Seq 18 of CET 9	1.619E-008	2.4
Seq 18 of CET 5	1.548E-008	2.3
Seq 18 of CET 19	1.439E-008	2.1
Seq 77 of CET 9	1.383E-008	2.0
Seq 77 of CET 5	1.354E-008	2.0
Seq 18 of CET 21	1.231E-008	1.8
Seq 18 of CET 20	9.704E-009	1.4
Seq 77 of CET 20	8.291E-009	1.2
Seq 20 of CET 10	8.183E-009	1.2
Seq 18 of CET 11	7.900E-009	1.2

TABLE 4.7-2 (Continued):
IMPORTANCE OF CONTAINMENT SEQUENCES TO RELEASE CATEGORIES

Source Term Category: 18 3.241E-007

	Amount	Percent
Seq 13 of CET 24	9.470E-008	29.2
Seq 13 of CET 27	4.715E-008	14.5
Seq 60 of CET 11	4.430E-008	13.7
Seq 3 of CET 11	3.008E-008	9.3
Seq 3 of CET 23	2.925E-008	9.0
Seq 60 of CET 1	2.038E-008	6.3
Seq 3 of CET 2	1.335E-008	4.1
Seq 3 of CET 25	1.316E-008	4.1
Seq 60 of CET 6	8.146E-009	2.5
Seq 70 of CET 17	6.884E-009	2.1
Seq 13 of CET 19	4.982E-009	1.5
Seq 3 of CET 12	4.701E-009	1.5

Source Term Category: 19 4.892E-009

	Amount	Percent
Seq 54 of CET 11	1.614E-009	33.0
Seq 54 of CET 2	7.159E-010	14.6
Seq 54 of CET 25	7.055E-010	14.4
Seq111 of CET 11	4.435E-010	9.1
Seq 54 of CET 23	2.926E-010	6.0
Seq 54 of CET 12	2.522E-010	5.2
Seq111 of CET 13	2.279E-010	4.7
Seq111 of CET 1	2.041E-010	4.2
Seq111 of CET 6	8.481E-011	1.7
Seq 54 of CET 13	8.292E-011	1.7
Seq 54 of CET 1	7.427E-011	1.5
Seq 54 of CET 7	6.279E-011	1.3

Source Term Category: 20 4.899E-009

	Amount	Percent
Seq 55 of CET 27	2.781E-009	56.8
Seq 55 of CET 24	9.475E-010	19.3
Seq 55 of CET 19	2.938E-010	6.0
Seq 55 of CET 28	2.896E-010	5.9
Seq112 of CET 9	9.230E-011	1.9
Seq112 of CET 5	8.703E-011	1.8
Seq112 of CET 17	6.901E-011	1.4
Seq 55 of CET 10	6.565E-011	1.3
Seq112 of CET 20	5.533E-011	1.1

TABLE 4.7-2 (Continued): IMPORTANCE OF CONTAINMENT SEQUENCES TO RELEASE CATEGORIES

Source Term Category: 21 1.682E-010

	Amount	Percent
Seq 53 of CET 24	7.576E-011	45.0
Seq 53 of CET 23	2.340E-011	13.9
Seq 53 of CET 27	2.224E-011	13.2
Seq 53 of CET 11	1.290E-011	7.7
Seq 53 of CET 2	5.724E-012	3.4
Seq 53 of CET 25	5.641E-012	3.4
Seq110 of CET 11	3.546E-012	2.1
Seq 53 of CET 19	2.349E-012	1.4
Seq 53 of CET 28	2.316E-012	1.4
Seq 53 of CET 12	2.017E-012	1.2
Seq110 of CET 13	1.822E-012	1.1
Seq110 of CET 1	1.632E-012	1.0

Source Term Category: 22 9.795E-006

	Amount	Percent
Seq113 of CET 11	7.979E-006	81.5
Seq113 of CET 1	9.519E-007	9.7
Seq 56 of CET 22	3.593E-007	3.7
Seq 56 of CET 1	3.464E-007	3.5
Seq113 of CET 16	1.425E-007	1.5

Source Term Category: 23 4.900E-009

	Amount	Percent
Seq114 of CET 11	3.992E-009	81.5
Seq114 of CET 1	4.762E-010	9.7
Seq 57 of CET 22	1.797E-010	3.7
Seq 57 of CET 1	1.733E-010	3.5
Seq114 of CET 16	7.128E-011	1.5

Source Term Category: 24 2.672E-008

	Amount	Percent
Seq 1 of CET 29	2.672E-008	100.0

Source Term Category: 25 1.543E-006

	Amount	Percent
Seq 1 of CET 30	1.250E-006	81.0
Seq115 of CET 11	2.218E-007	14.4
Seq115 of CET 1	3.402E-008	2.2

Source Term Category: 26 3.725E-007

	Amount	Percent
Seq 1 of CET 31	3.725E-007	100.0

TABLE 4.7-3

REPRESENTATIVE SEQUENCES FOR RELEASE FRACTION ANALYSIS

MAAP Case Number	Description
C51	SGTR (1 tube double-ended) no AFW, secondary relief valve on broken s/g stuck open.
C57	SGTR (1 tube double-ended) no AFW, secondary relief valve cycles normally.
C61	2" diameter SLOCA, injection, no sprays, no AFW, recirc or CHR, late 0.1 sq. ft containment leak failure.
C62	2" diameter SLOCA, no injection, no AFW, no sprays, late 0.1 sq. ft containment leak failure.
C63	V sequence, 6" diameter unsubmerged break in PAB, no spray.
C64	2" SLOCA sprays operate early only, late 1.0 sq. ft containment rupture.
C65	SBO no AFW 0.1 sq. ft containment leak failure at vessel rupture.
C67	SBO, no AFW, 1.0 sq. ft containment rupture failure at vessel rupture.

TABLE 4.7-4

MAAP-CALCULATED RELEASE FRACTIONS.

Case	NOBL	CSI	TEO2	SRO	MOO2	CSOH	BAO	LA2O3	CEO2	SB	TE2	UO2	TYPE	DESCRIPTION
C63	1.0	.70	2.4E-5	.024	.055	.70	.059	.032	.032	.54	.37	1E-4	I	V Sequence
C62	1.0	.0015	0.	6.2E-6	2.0E-4	.0028	6.9E-5	9.3E-7	1.7E-7	5.6E-3	0	0	III	SBLOCA Late CF Leak Inj
C61	.93	.067	.026	1.5E-5	9.0E-6	.066	4.7E-5	2.5E-6	2.2E-5	.055	2.4E-4	1.5E-7	II	SBLOCA Late CF Leak No Inj
C57	.72	.076	0.	2.8E-4	.012	.064	2.9E-3	2.2E-5	2.4E-5	.038	0	0	II	SGTR No SORV
C51	.85	.25	0.	1.0E-3	.043	.22	.011	8.2E-5	8.4E-5	.12	0	0	I	SGTR with SORV
C65	.99	.16	.017	6.6E-4	7.3E-3	.13	3.3E-3	6.7E-5	5.6E-4	.04	1.2E-4	1.8E-6	II	SBO Early CF Rupture
C67	.99	.17	.018	6.6E-4	7.2E-3	.14	3.3E-3	6.8E-5	5.7E-4	.04	1.5E-4	1.9E-6	II	SBO Early CF Leak
C64	1.0	2.6E-4	0	2.E-11	7.E-10	.001	2.E-10	1.E-12	4.E-12	.010	0	0	IV	SLOCA Late CF E.Sprays

TABLE 4.7-5

MAAP FISSION PRODUCT SPECIES [a]

Specie Number	Specie I.D.	Composition
1	NOBLES	Noble Gases and Radioactively Inert Aerosols [b]
2	CSI	CsI + RbI
3	TEO2	TeO_2
4	SRO	SrO
5	MOO2	MoO_2
6	CSOH	CsOH + RbOH
7	BAO	BaO
8	LA203	$La_20_3 + Pr_20_3 + Nd_20_3 + Sm_20_3 + Y_2O_3$
9	CE03	$Ce0_2$
10	SB	Sb
11	TE2	Te_2
12	U02	$U0_2 + Np0_2 + Pu0_2$

Notes: see following pages

TABLE 4.7-5 (Continued)

MAAP FISSION PRODUCT SPECIES [a]

Notes

(a) Explanation of Species

Specie (1): The Specie (1) vapors represent the noble gases. the Specie (1) aerosols are used to represent all non-radioactive aerosols (except for water droplets which are tracked separately in the thermal-hydraulic routines). The aerosol and deposited masses represent the core structural materials along with any concrete aerosols generated ex-vessel. the Specie (1) solid aerosols are assumed to have negligible vapor pressure at the temperatures of interest except in the core or core debris. The vapor pressure assumption used in the core and core debris are discussed in the write-ups for subroutines FPRATP and METOXA.

Specie (2): This specie represents the compounds CsI and RbI. All of the iodine is assumed to combine with the alkali fission products since the molar ratio is about 10 to 1 in favor of cesium and rubidium. Due to the dominance of cesium, CsI properties are chosen.

Specie (3): This specie represents tellurium that is oxidized to TeO_2. Tellurium released in-core is assumed to form TeO_2 directly. Tellurium released ex-vessel is assumed to be elemental; it is allowed to oxidize to TeO_2 in the cavity if steam or oxygen are present (see subrouting METOXA).

Specie (4): Strontium is primarily released in elemental form ex-vessel and is assumed to oxidize to SrO in containment. In-vessel release is also assumed to lead to SrO formation.

Specie (5): This specie is MoO_2. This chemical state is assumed since molybdenum is thought to be mainly released during concrete attack.

Specie (6): This specie includes CsOH and RbOH. It represents any cesium and rubidium that is left over after combination with iodine.

Specie (7): This specie is BaO. Barium behaves similarly to strontium due to its chemical periodicity.

Specie (8): This specie represents the lanthanides. all sesquioxides in the lanthanide series are grouped together due to similar chemical behavior. These are rather nonvolatile, but in-vessel release is allowed. They are believed primarily to be released ex-vessel as monixides, which are further oxidized in containment.

Specie (9): Cerium behavior is similar to lanthanide behavior but stoichiometry and vapor pressure differ enough to warrant a separate group.

Specie (10): Antimony is released in-vessel and ex-vessel in elemental form.

Specie (11): Tellurium released ex-vessel which doesn't oxidize in the cavity remains "frozen" as Te_2.

Specie (12): Uranium and the transuranics are grouped separately from the other fission products such as cesium because of their different radiological characteristics. These are only released ex-vessel, and are assumed to oxidize (or reduce) to the dioxide form in containment.

(b)

A similar scheme is used to track structural materials in the core and core debris. As described above, all such materials are tracked as Specie (1) "fission product" aerosols after they are released. The structural materials which are accounted for in the PWR code are:

a. Group (1): cadmium
b. Group (2): indium
c. Group (3): silver
d. Group (4): tin
e. Group (5): manganese

TABLE 4.7-6

COMPARISON OF REACTOR SAFETY STUDY, NUREG-0956, IPPSS, AND THIS RISK ASSESSMENT RESULTS FOR BLACKOUT WITH EARLY CONTAINMENT FAILURE AND INTERFACING SYSTEM LOCA CASES

Release Fractions (1)

Sequence	Noble Gases	Iodine (CSI)	Cesium (CSOH)	Tellurium (TE2)	Strontium (SRO)	Lanthanium (LA2O3)	Barium (BAO)	Cerium (CEO2)
Wash-1400 PWR2 TLMB'-γ,-δ	0.9	0.7	0.5	0.3	0.06	4E-3		
IPPSS Z-5	0.8	0.2	0.2	0.25	0.02	4E-3	0.025	
NUREG-0956 SBO Early Overpress-urization	1.0	0.2	0.2	0.1	0.02	2E-4		
This Study C65 SBO with early OP CF	1.0	0.2	0.1	0.02	7E-4	7E-5	0.003	
- - -								
IPPSS 2 - BYPASS	0.9	0.7	0.5	0.3	0.06	4E-3	0.06	
NUREG-0956 ISLOCA (V w/o water)	1.0	0.3	0.3	0.06	0.005	3E-4	4E-3	4E-4
This Study Case C63 (V Sequence)	1.0	0.7	0.7	0.4	0.02	4E-4	0.06	3E-2

Note: (1) Headings in parentheses are MAAP Species used for release fraction. Main headings are surrogates as defined in Table 4.16 of NUREG-0956

TABLE 4.7-7:

COMPARISON OF IPSSS AND MAAP RELEASE FRACTIONS

	CASE(1)	IODINE(2)		CESIUM(3)		SB(4)		LA(5)		DESCRIPTION
MAAP	IPPSS	IPPSS	MAAP	IPPSS	MAAP	IPPSS	MAAP	IPPSS	MAAP	
C65	Z-5	.2	.16	.25	.13	.25	.04	4E-3	7E-5	EARLY CF RUPTURE
C63	2	.7	.7	.5	.7	.3	.54	4E-3	.032	BYPASS
C62	2R	.009	.0015	.2	.0028	.03	.006	7E-4	9E-7	LATE CF DEBRIS FLOOD
C61	2RW	.1	.067	.3	.066	.03	.055	5E-3	3E-6	LATE CF DEBRIS DRY

NOTES

(1) IPPSS cases are described in Tables 5.4-1 and 5.4-2 of the IPPSS Document (IPPSS 1982). Reactor Safety Study (RSS 1976) fission product specie groups are used.

(2) IPPSS = Iodine, MAAP = CSI

(3) IPPSS = Cs-Rb, MAAP = CSOH

(4) IPPSS = Te-Sb, MAAP = SB

(5) IPPSS = La, MAAP = LA2O3

TABLE 4.7-8

ASSIGNMENT OF RELEASE TYPES TO SOURCE TERM CATEGORIES.

STC Number(s)	RELEASE TYPE	MAAP CASE	BASIS FOR TYPE
1	V		No CF.
2-7	II		Very low freq. and expected less release than STC 8.
8	II	C67	Applicable calculated case.
9	II	C65	Applicable calculated case.
10-12	IV		Expected lower rel. than STC 13 which is very low itself.
13	IV	C64	Applicable calculated case.
14	III	C62	Applicable calculated case.
15	III		Judged to be similar to STC 14.
16	II	C61	Applicable calculated case.
17	II		Judged to be similar to STC 16
18	IV		Based on IPPSS 6 release category.
19-20	II		Judged similar to STC 9.
21	I		Based on IPPSS Z-1 release category.
22	V		No containment failure.
23	IV		Very low frequency and judged to be very low release.
24	I	C63	Applicable calculated case.
25	II	C57	" " "
26	I	C51	" " "

NOTE: The assignment of MAAP cases (and IPPSS cases) to release types is based primarily on the iodine release fraction.

Table 4.7-9
STC CONTRIBUTORS TO RELEASE CATEGORIES

Contributors to TYPE I Releases

Source Term Class	Frequency per r-yr
STC26	3.725E-007
STC24	2.672E-008
STC21	1.682E-010

Contributors to TYPE II Releases

Source Term Class	Frequency per r-yr
STC25	1.543E-006
STC16	1.098E-006
STC17	6.846E-007
STC2	2.145E-008
STC8	1.535E-008
STC20	4.899E-009
STC19	4.892E-009
STC3	1.687E-009
STC9	1.615E-009
STC4	1.003E-009
STC5	8.454E-011
STC6	3.213E-011
STC7	1.636E-011

Contributors to TYPE III Releases

Source Term Class	Frequency per r-yr
STC14	1.008E-009
STC15	5.835E-010

Contributors to TYPE IV Releases

Source Term Class	Frequency per r-yr
STC10	3.887E-007
STC18	3.241E-007
STC11	2.248E-007
STC13	4.502E-008
STC12	4.463E-008
STC23	4.900E-009

Contributors to TYPE V Releases

Source Term Class	Frequency per r-yr
STC1	1.672E-005
STC22	9.795E-006

Table 4.7-10

PDS CONTRIBUTORS TO RELEASE TYPE CATEGORIES

Contributors to TYPE I Releases

Plant Damage State	Frequency per r-yr (1)
PDS31	3.73E-007
PDS29	2.67E-008

Contributors to TYPE II Releases

Plant Damage State	Frequency per r-yr (1)
PDS30	1.25E-006
PDS28	4.63E-007
PDS27	4.48E-007
PDS11	2.52E-007
PDS9	2.42E-007
PDS5	2.28E-007
PDS20	1.45E-007
PDS10	1.05E-007

Contributors to TYPE III Releases

Plant Damage State	Frequency per r-yr (1)
PDS7	8.63E-010

Contributors to TYPE IV Releases

Plant Damage State	Frequency per r-yr (1)
PDS13	5.65E-007

Contributors to TYPE V Releases

Plant Damage State	Frequency per r-yr (1)
PDS11	1.20E-005
PDS27	5.07E-006
PDS1	1.83E-006
PDS24	1.80E-006
PDS2	1.41E-006
PDS25	1.39E-006
PDS23	5.56E-007
PDS19	5.35E-007
PDS22	3.77E-007
PDS6	2.14E-007
PDS16	2.10E-007
PDS12	2.09E-007
PDS17	1.76E-007
PDS7	1.25E-007
PDS28	1.15E-007

Table 4.7-10 (Continued)
PDS CONTRIBUTORS TO RELEASE TYPE CATEGORIES

NOTE: (1) This is the frequency at which this release type would be expected to occur stemming from the particular plant damage state. A plant damage state may contribute to the occurrence of all five release types through various CET paths.

(2) PDS #s in this table correspond to the Level 2 designation (see section 3.1.6)

Table 4.7-11
CET CONTRIBUTORS TO RELEASE CATEGORIES

Contributors to TYPE I Releases

CET Sequence	Frequency/r-yr[1]
Seq 1 of CET 31	3.725E-007
Seq 1 of CET 29	2.672E-008
Seq 53 of CET 24	7.576E-011
Seq 53 of CET 23	2.340E-011
Seq 53 of CET 27	2.224E-011
Seq 53 of CET 11	1.290E-011

Contributors to TYPE II Releases

CET Sequence	Frequency/r-yr[1]
Seq 1 of CET 30	1.250E-006
Seq 16 of CET 28	2.851E-007
Seq 16 of CET 27	2.742E-007
Seq115 of CET 11	2.218E-007
Seq 18 of CET 28	1.416E-007
Seq 18 of CET 27	1.362E-007
Seq 73 of CET 9	1.092E-007
Seq 73 of CET 5	1.069E-007
Seq 73 of CET 20	6.547E-008
Seq 16 of CET 10	6.463E-008
Seq 75 of CET 9	5.425E-008
Seq 75 of CET 5	5.313E-008
Seq 20 of CET 28	3.610E-008
Seq 20 of CET 27	3.472E-008
Seq115 of CET 1	3.402E-008
Seq 16 of CET 9	3.258E-008
Seq 75 of CET 20	3.252E-008
Seq 18 of CET 10	3.210E-008
Seq 16 of CET 5	3.116E-008
Seq 16 of CET 19	2.897E-008
Seq 16 of CET 21	2.479E-008
Seq 16 of CET 20	1.953E-008
Seq 18 of CET 9	1.619E-008
Seq 16 of CET 11	1.590E-008
Seq 18 of CET5	1.548E-008
Seq 18 of CET 19	1.439E-008
Seq 77 of CET9	1.383E-008

Table 4.7-11 (Cont.)
CET CONTRIBUTORS TO RELEASE CATEGORIES

Contributors to TYPE II Releases (cont)

CET Sequence	Frequency/r-yr[1]
Seq 77 of CET5	1.354E-008
Seq 18 of CET 21	1.231E-008
Seq115 of CET 13	1.139E-008

Contributors to TYPE III Releases

CET Sequence	Frequency/r-yr[1]
Seq 15 of CET7	5.464E-010
Seq 15 of CET6	2.686E-010
Seq 17 of CET7	2.684E-010
Seq 15 of CET8	1.927E-010
Seq 17 of CET6	1.319E-010

Contributors to TYPE IV Releases

CET Sequence	Frequency/r-yr[1]
Seq 62 of CET 13	2.467E-007
Seq 64 of CET 13	1.212E-007
Seq 13 of CET 24	9.470E-008
Seq 5 of CET 13	6.555E-008
Seq 13 of CET 27	4.715E-008
Seq 60 of CET 11	4.430E-008
Seq 62 of CET 3	3.935E-008
Seq 7 of CET 13	3.220E-008
Seq 3 of CET 11	3.008E-008
Seq 3 of CET 23	2.925E-008
Seq 63 of CET 13	2.833E-008
Seq 66 of CET 13	2.166E-008
Seq 60 of CET 1	2.038E-008

Table 4.7-11 (Cont.)
CET CONTRIBUTORS TO TYPE RELEASE CATEGORIES

Contributors to TYPE V Releases

CET Sequence	Frequency/r-yr[1]
Seq113 of CET 11	7.979E-006
Seq 11 of CET 27	4.815E-006
Seq 1 of CET 11	3.071E-006
Seq 11 of CET 24	1.515E-006
Seq 1 of CET 2	1.363E-006
Seq 1 of CET 25	1.344E-006
Seq113 of CET 1	9.519E-007
Seq 58 of CET 11	7.088E-007
Seq 11 of CET 19	5.086E-007
Seq 1 of CET 12	4.800E-007
Seq 1 of CET 23	4.680E-007
Seq 56 of CET 22	3.593E-007
Seq 56 of CET 1	3.464E-007
Seq 58 of CET 1	3.262E-007
Seq 12 of CET 24	2.841E-007
Seq113 of CET 16	1.425E-007
Seq 12 of CET 27	1.415E-007
Seq 1 of CET 1	1.413E-007
Seq 59 of CET 11	1.329E-007
Seq 58 of CET 6	1.303E-007
Seq 1 of CET 7	1.177E-007
Seq 14 of CET 28	1.152E-007
Seq 14 of CET 27	1.108E-007
Seq 68 of CET 17	1.101E-007
Seq 2 of CET 11	9.025E-008
Seq 2 of CET 23	8.775E-008
Seq 59 of CET 1	6.115E-008
Seq 1 of CET 6	5.783E-008
Seq 11 of CET 16	4.979E-008
Seq 11 of CET 17	4.339E-008
Seq 2 of CET 2	4.006E-008
Seq 2 of CET 25	3.948E-008
Seq 11 of CET 18	3.863E-008
Seq 11 of CET 4	3.540E-008
Seq 4 of CET 13	2.952E-008
Seq 14 of CET 10	2.611E-008
Seq 59 of CET 6	2.444E-008
Seq 69 of CET 17	2.065E-008

TABLE 4.8-1 LEVEL 2 SENSITIVITY ANALYSIS

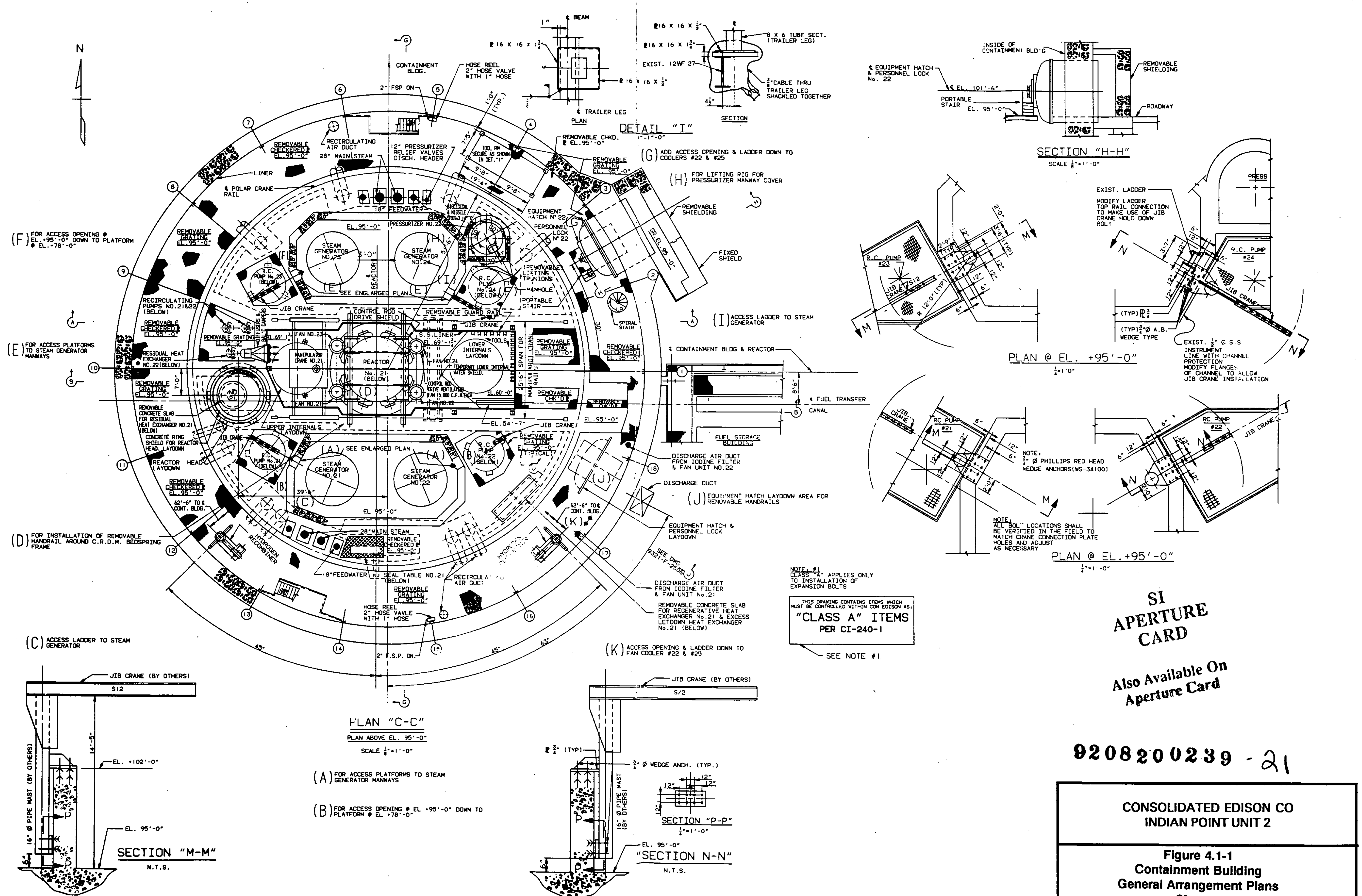
Case(s)	Parameter Varied	Variation(s)	Result Investigated
A1,A2	Induced Hot Leg Failure Probability	(1,0)	Containment Failure Times, Debris Cooled In-vessel
C1,C2	Probability of In-vessel Debris Cooling for LBLOCA without Accumulators	(1,0)	Debris Cooled In-vessel
D1,D2	Probability of In-vessel Debris Cooling for Late Depressurization Sequences	(1,0)	Debris Cooled In-vessel
E1,E2	Probability of In-vessel Debris Cooling for Power Recovery after Core Damage	(1,0)	Debris Cooled In-vessel
F1,F2	Probability of In-vessel Debris Cooling (C, D, and E above combined)	(1,0)	Debris Cooled In-vessel
H1,H2	Probability of Large DCH Event	(1,0)	Early Containment Failure
J2	Containment Failure Pressure	(no cf <120psia)	Containment Failure Time and Mode

TABLE 4.8-1 (Continued)

LEVEL 2 SENSITIVITY ANALYSIS

Case(s)	Parameter Varied	Variation(s)	Result Investigated
K1	Probability of Early Recirculation (due to energetic events, environmental conditions) Spray Failure	(1,0)	Containment Failure Time.
K2	Probability of Late Recirculation (due to Energetic Events or environmental conditions) Spray Failure	(1,0)	Containment Failure Time.
L1	Probability of Debris Cooling Ex-vessel	(1,0)	Containment Failure Time
M1	Probability of Complete Spray Failure	(1,0)	Containment Failure Time

FIGURES FOR SECTION 4



SI APERTURE CARD

Also Available On Aperture Card

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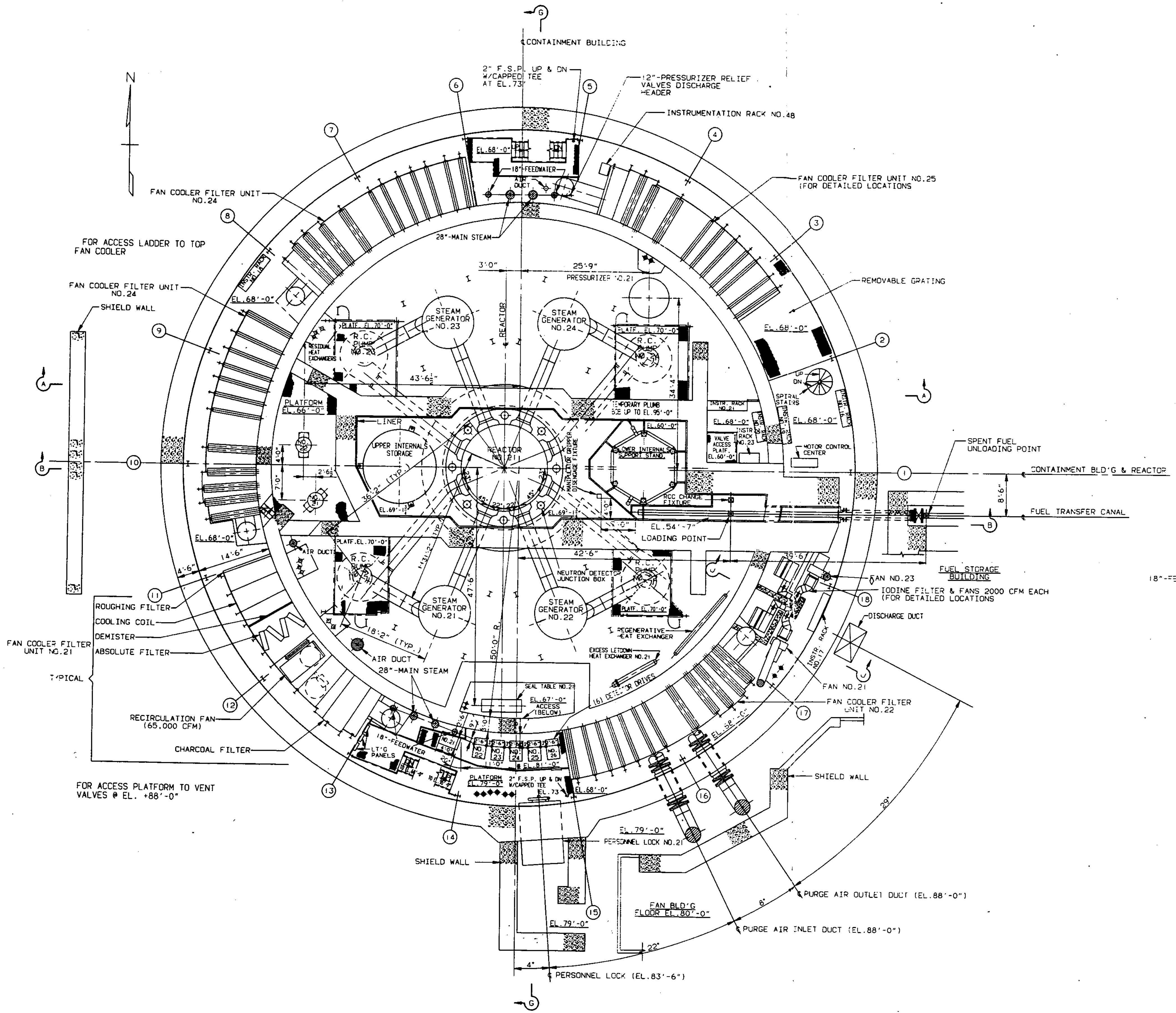
CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

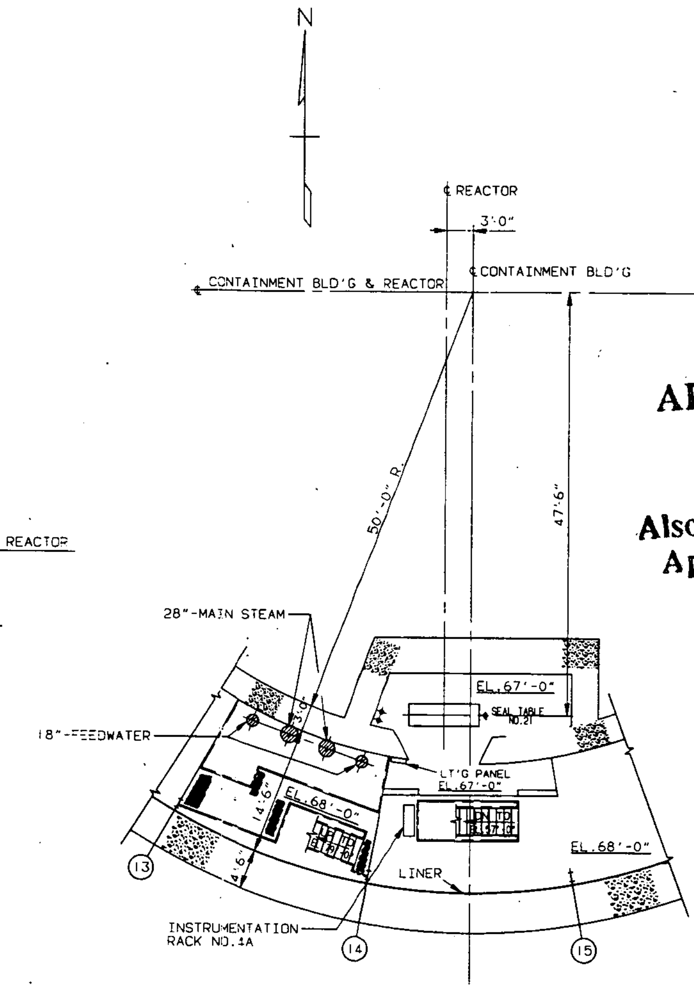
Figure 4.1-1
Containment Building
General Arrangement Plans
Sheet 1



PLAN "D-D"

PLAN ABOVE EL.68'-0"

SCALE 1/8"=1'-0"



PARTIAL PLAN ABOVE EL.68'-0"

SOUTH END

SCALE 1/8"=1'-0"

SI APERTURE CARD

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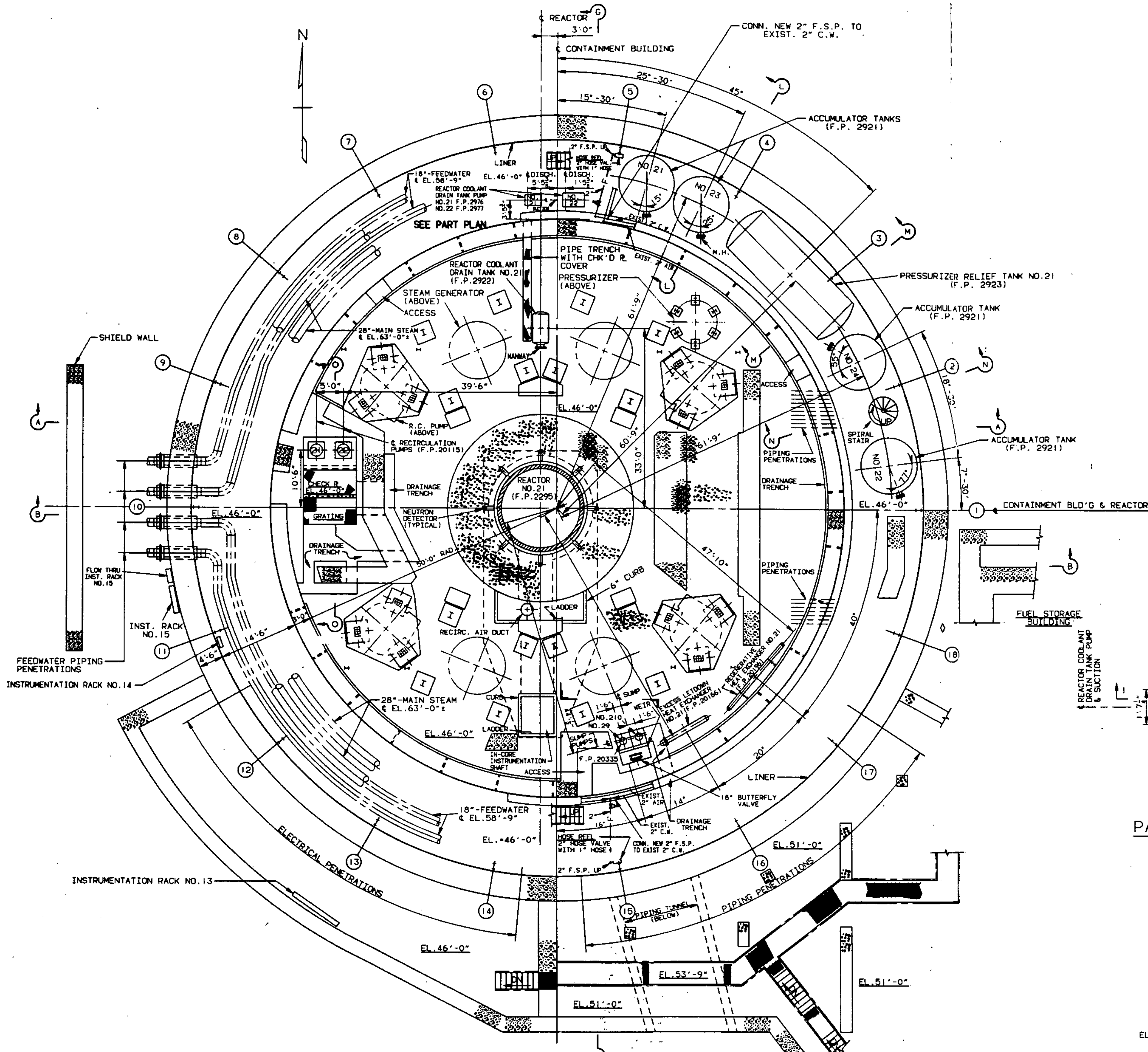
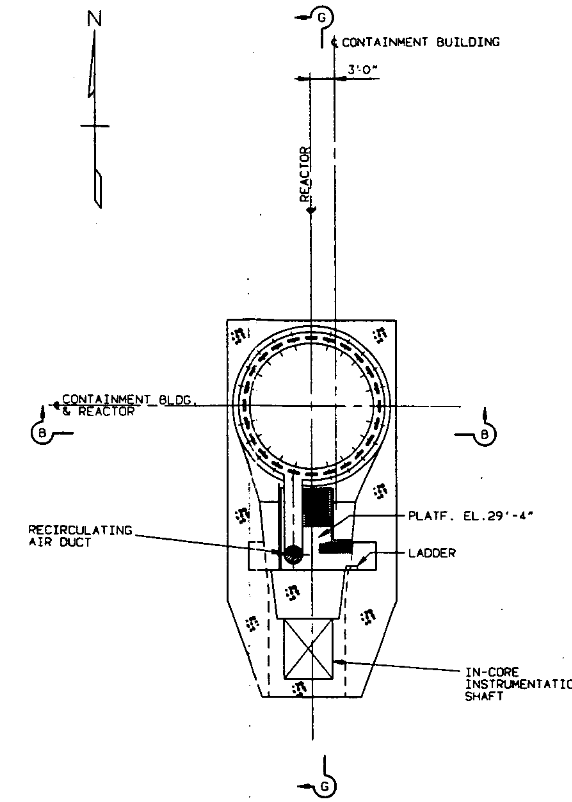
CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 4.1-2
Containment Building
General Arrangement Plans
Sheet 2



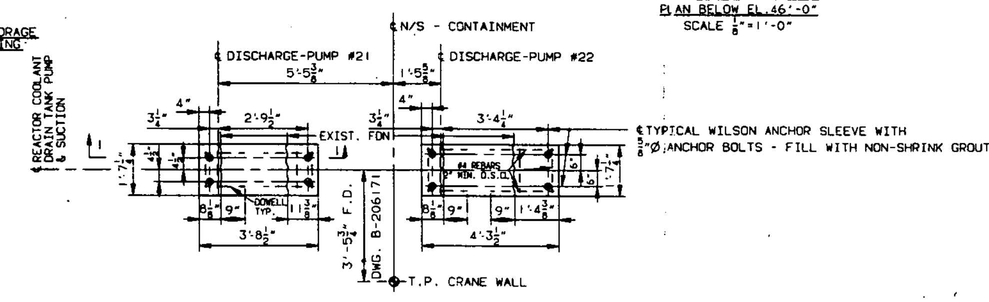
PLAN "E-E"

PLAN ABOVE EL.46'-0"
SCALE 1/8"=1'-0"



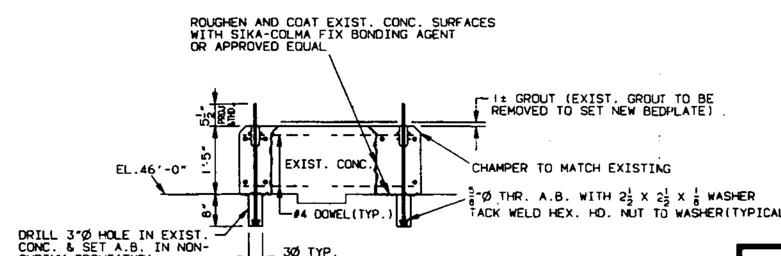
PLAN "F-F"

PLAN BELOW EL.46'-0"
SCALE 1/8"=1'-0"



PART PLAN-FOUNDATION R.C.D.T. PUMPS

1/2"=1'-0"



SECTION I-I

3/4"=1'-0"

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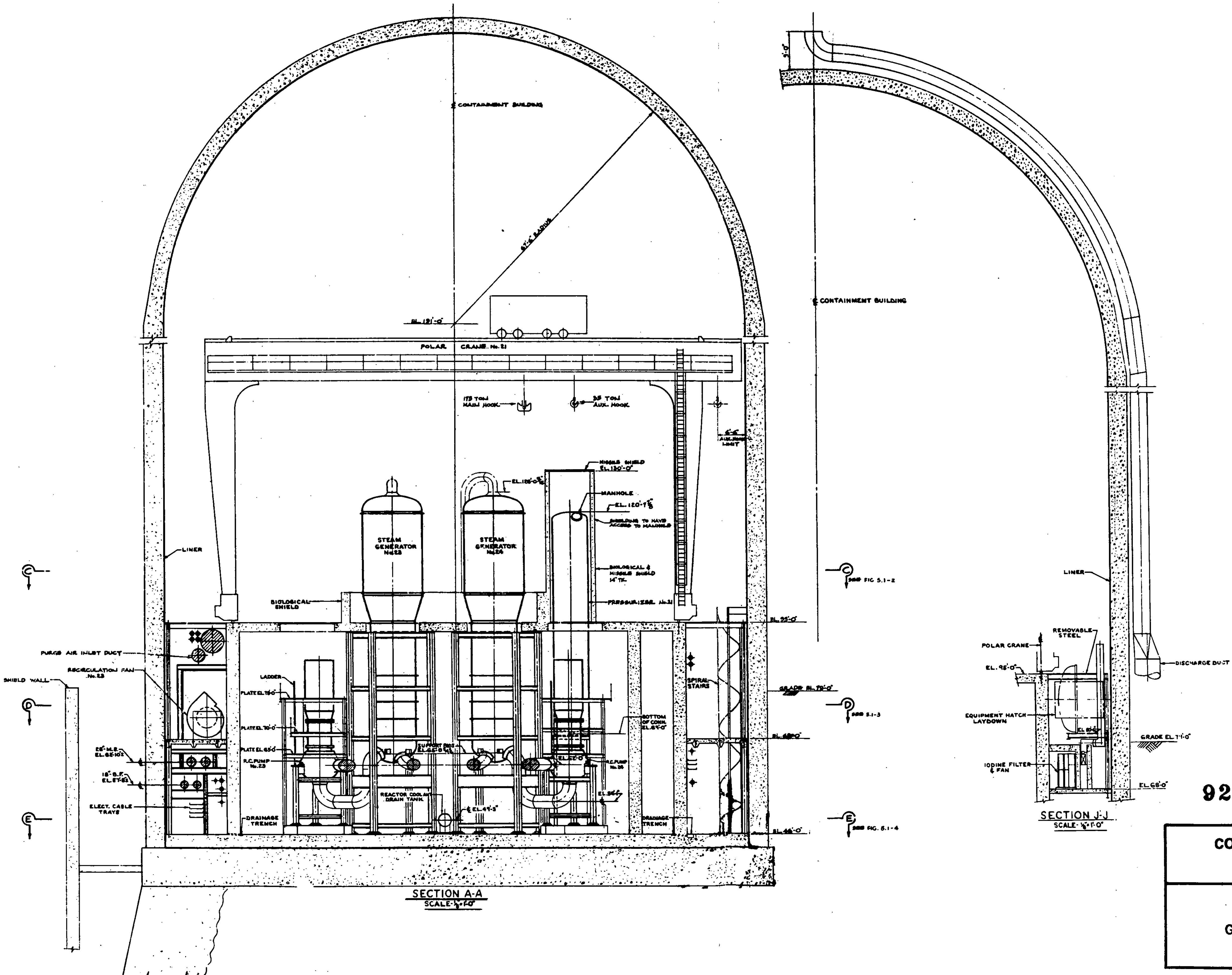
CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 4.1-3
Containment Building
General Arrangement Plans
Sheet 3



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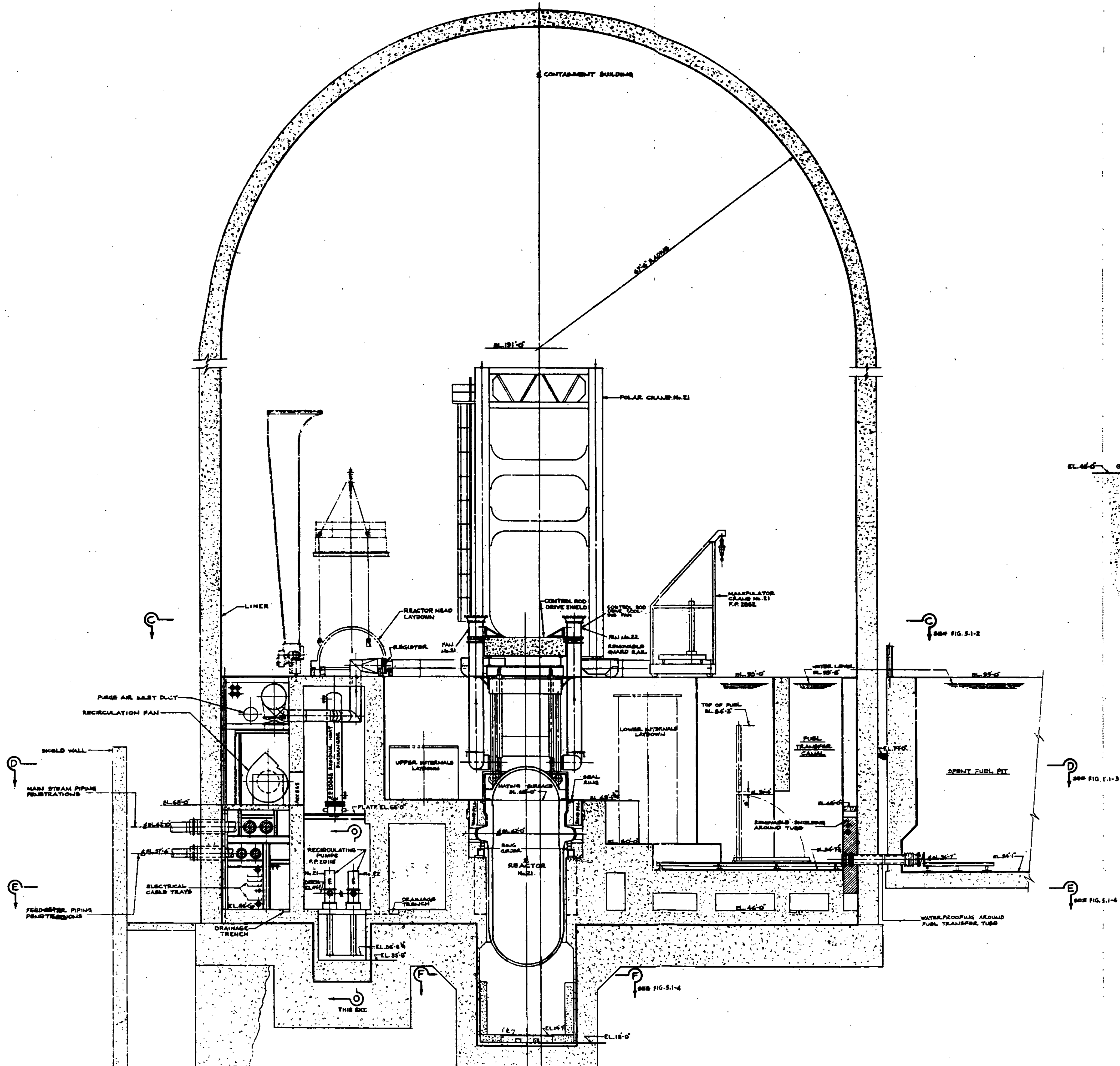
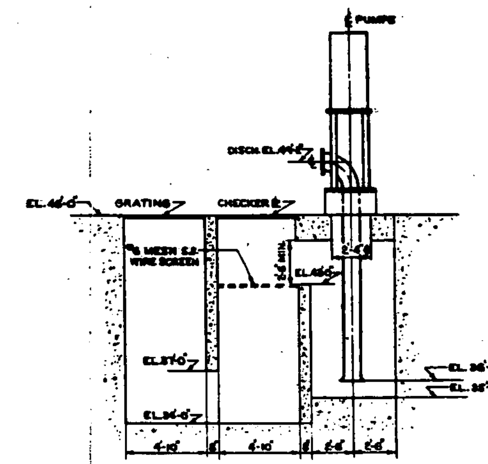
CONSOLIDATED EDISON CO.
INDIAN POINT UNIT 2

Figure 4.1-4
Containment Building
General Arrangement Plans
Sheet 4



SECTION 'B-B'



SECTION 'O-O'

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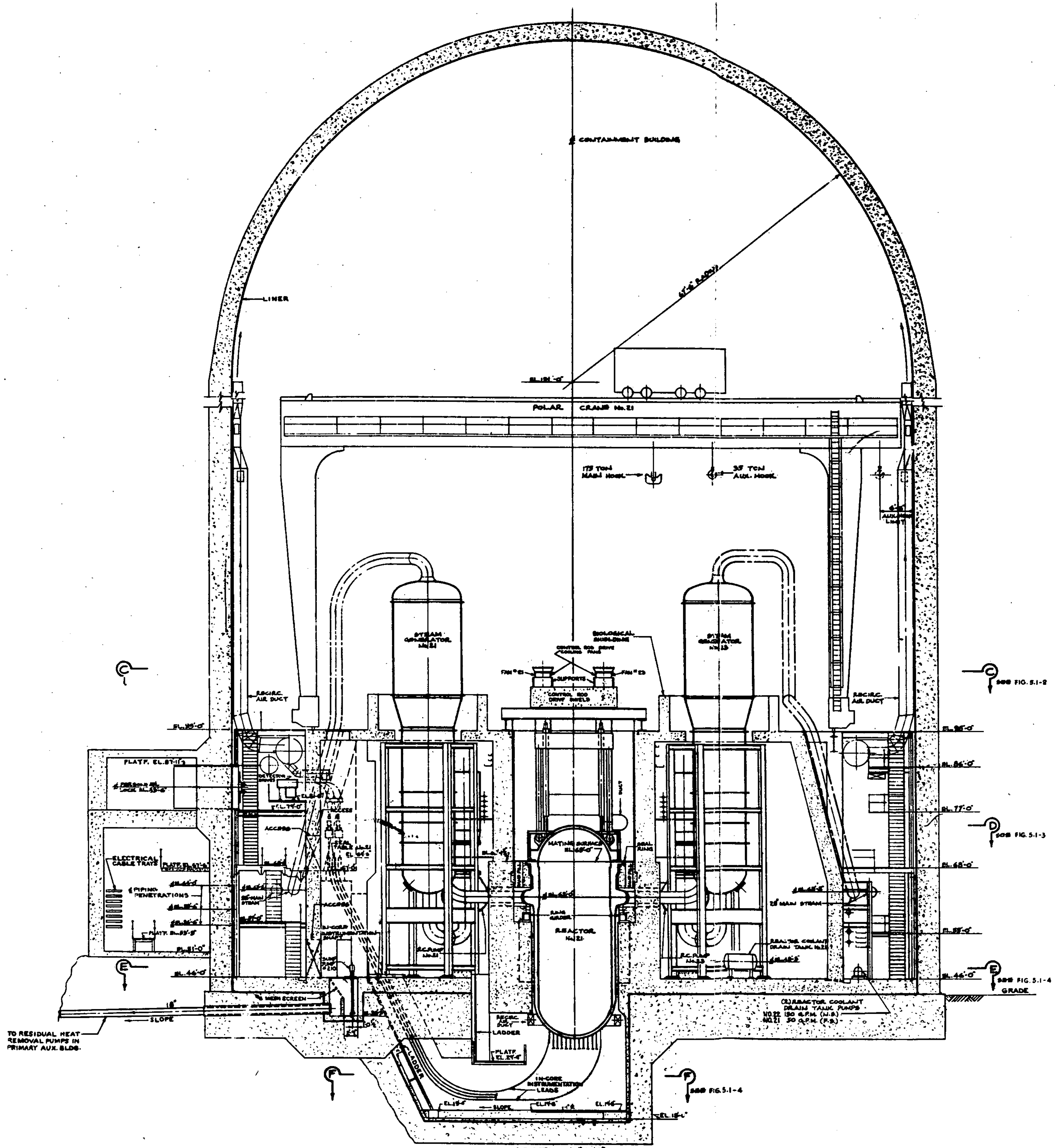
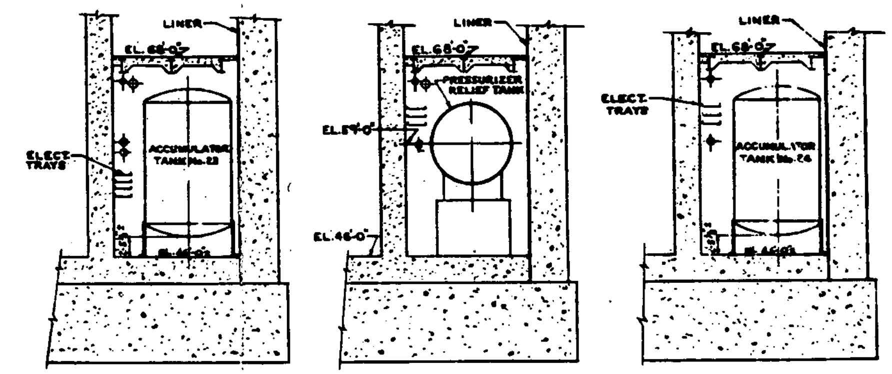
CONSOLIDATED EDISON CO.
INDIAN POINT UNIT 2

Figure 4.1-5
Containment Building
General Arrangement Plans
Sheet 5



SECTION "G-G"



SECTION L-L

SECTION M-M

SECTION N-N

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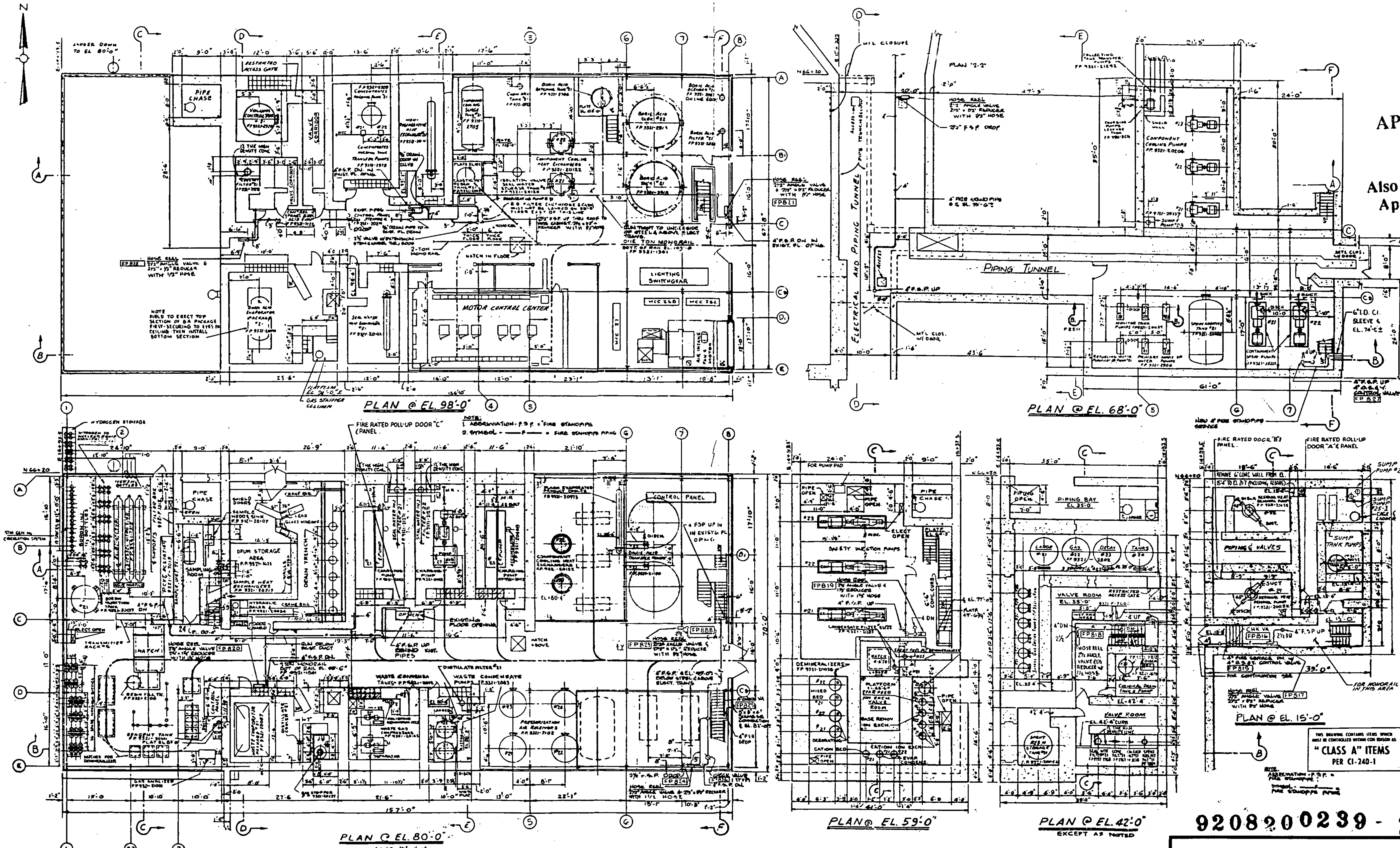
CONSOLIDATED EDISON CO.
INDIAN POINT UNIT 2

Figure 4.1-6
Containment Building
General Arrangement Plans
Sheet 6

Revision 2



SI
APERTURE
CARD

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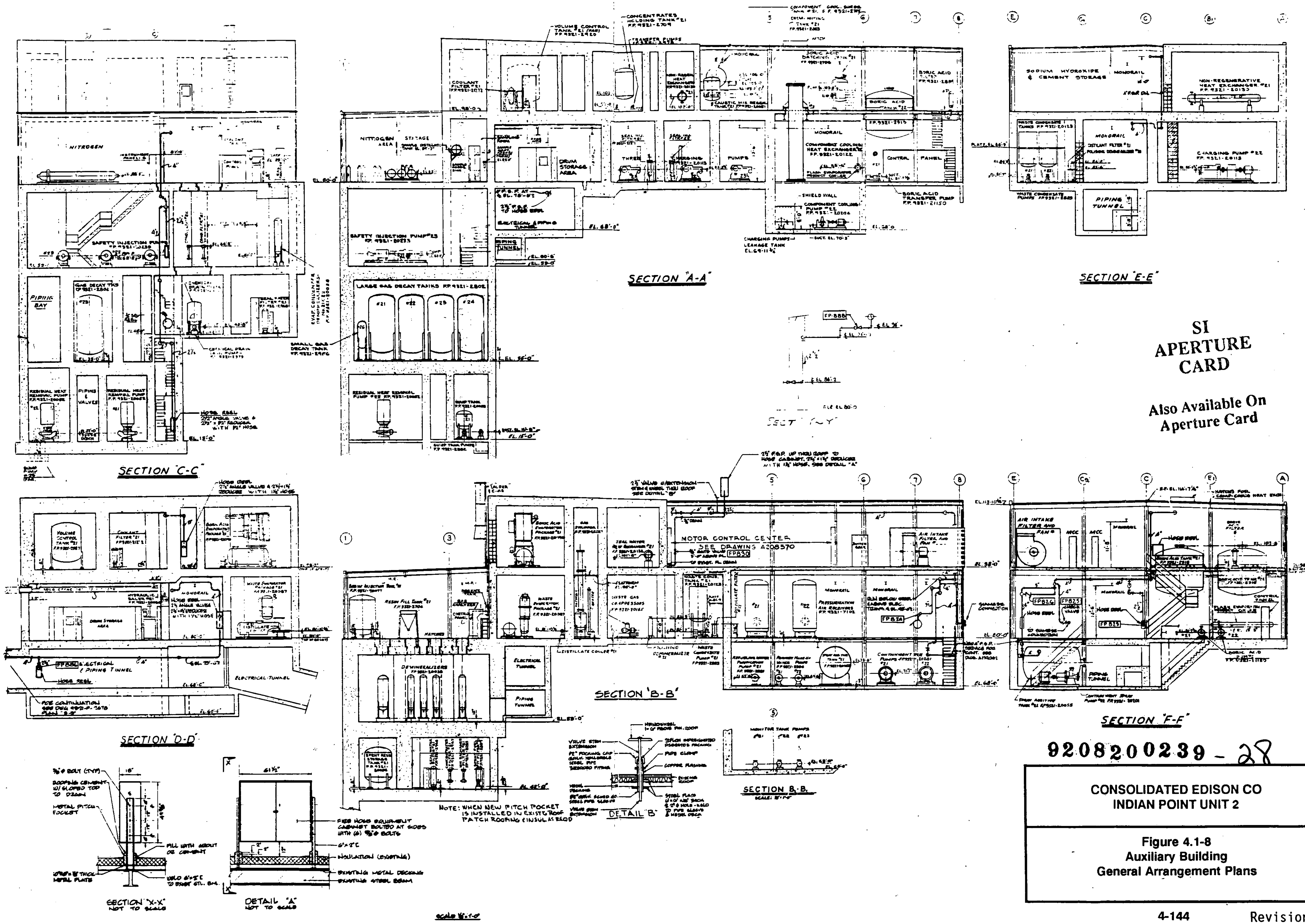
CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 4.1-7
Auxiliary Building
General Arrangement Plans



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CONSOLIDATED EDISON CO
INDIAN POINT UNIT 2

Figure 4.1-8
Auxiliary Building
General Arrangement Plans

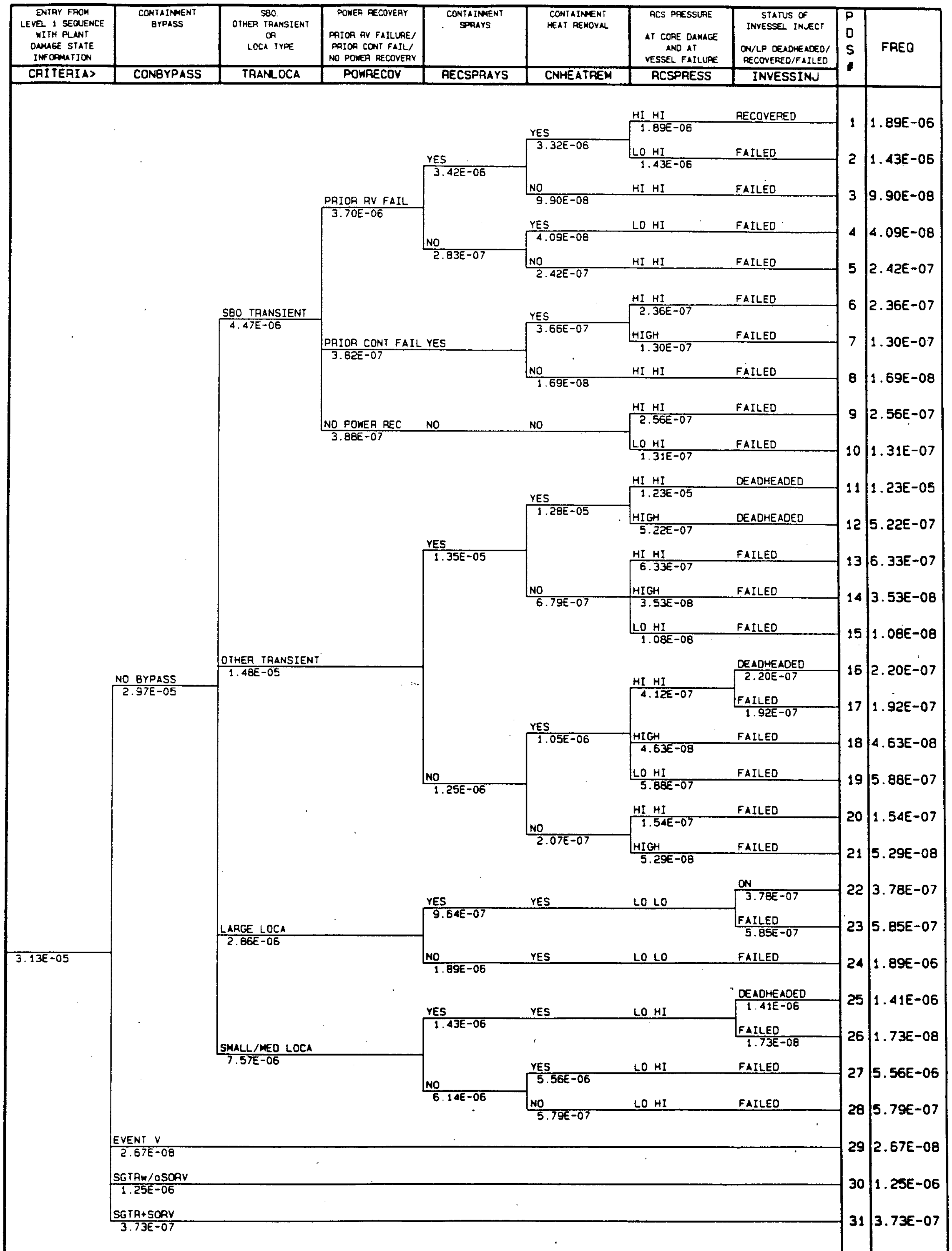


DIAGRAM: REV9-IP2.PDD 1 MAY 92 DATA FILE: 21 JUL 92 Sum = 3.132E-005

Figure 4.3-1

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

PLANT DAMAGE STATE GROUPING LOGIC

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_1.COB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

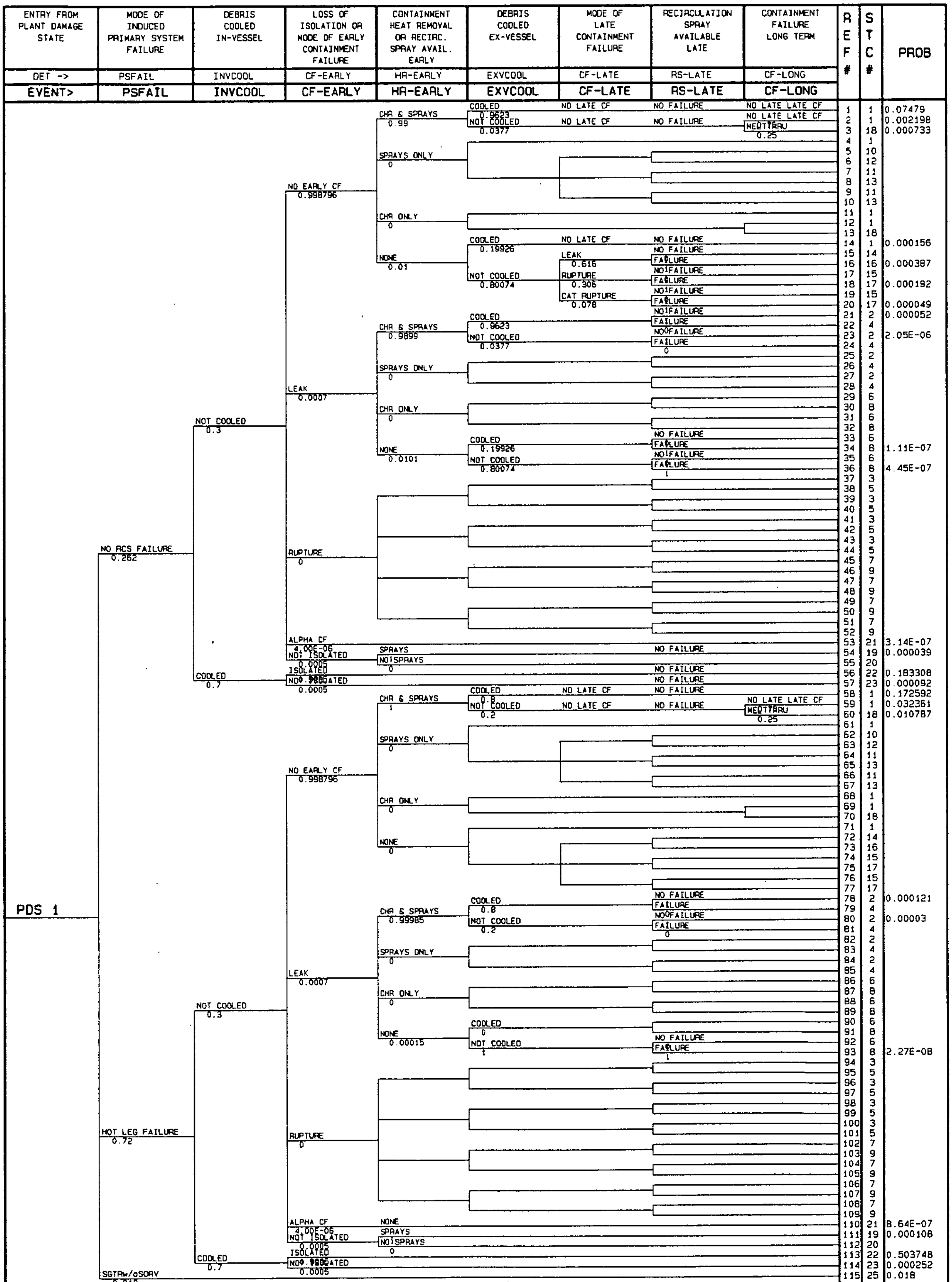


Figure 4.5-1

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for POS 1

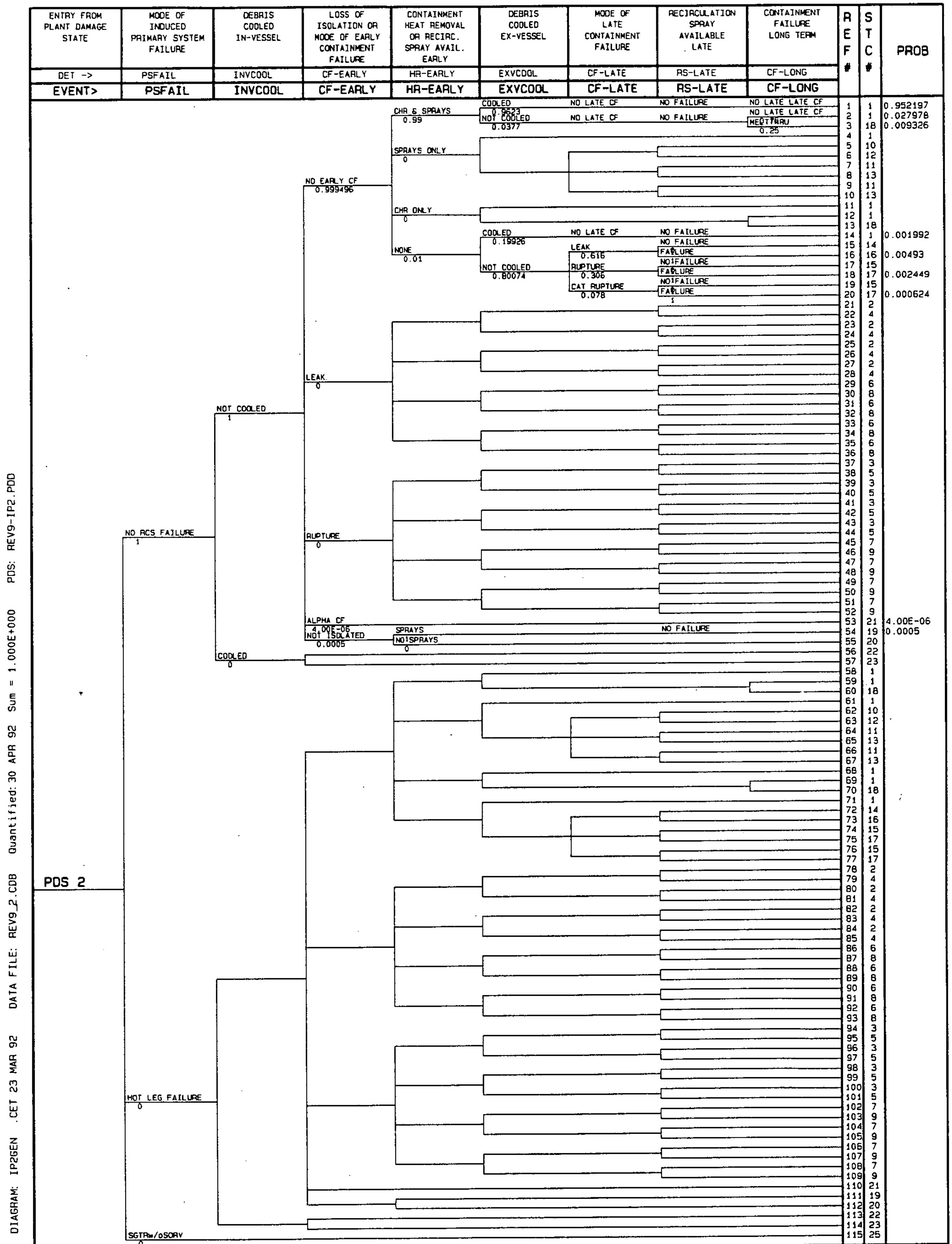


Figure 4.5-2

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 2

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_3.COB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

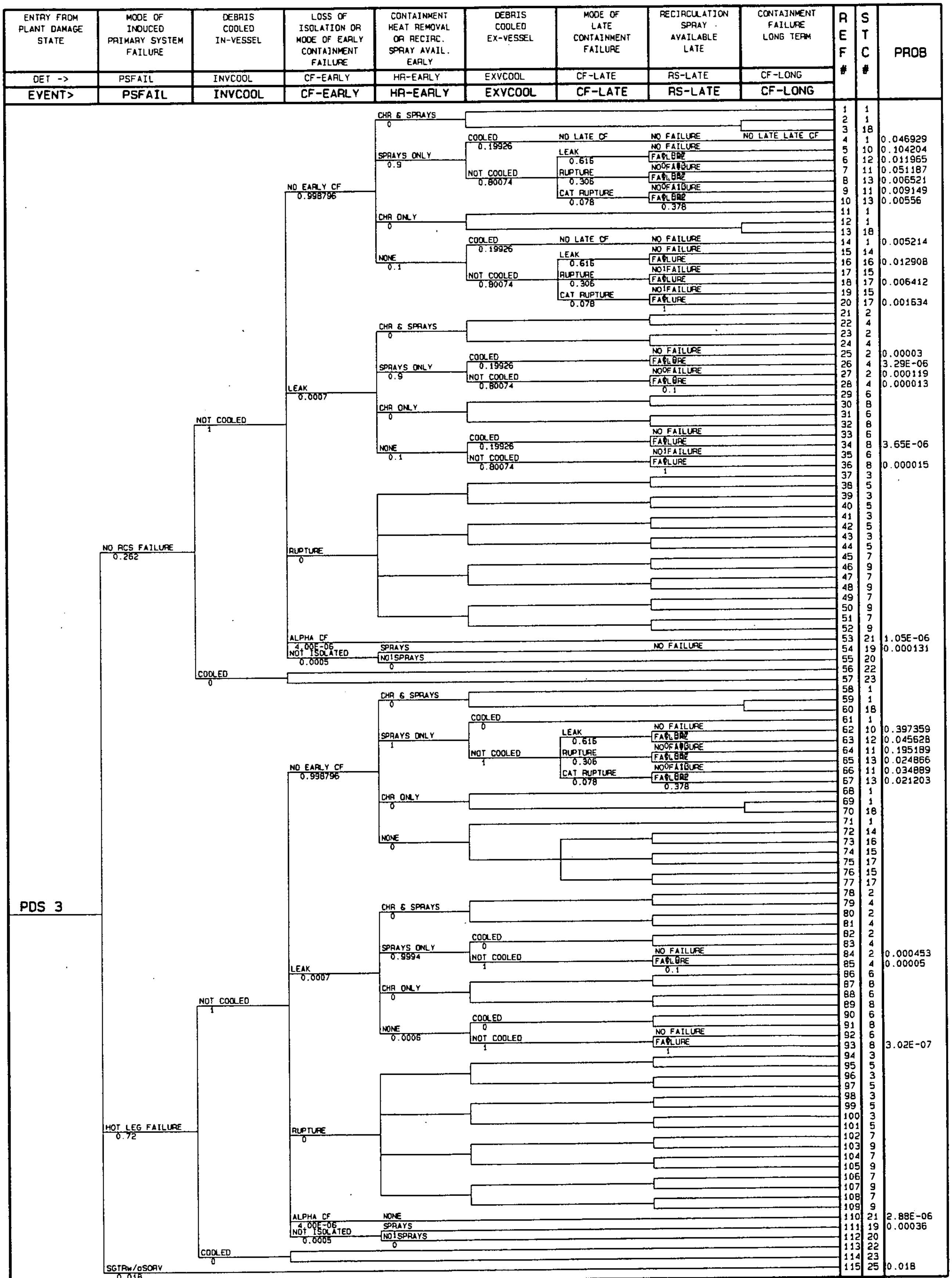
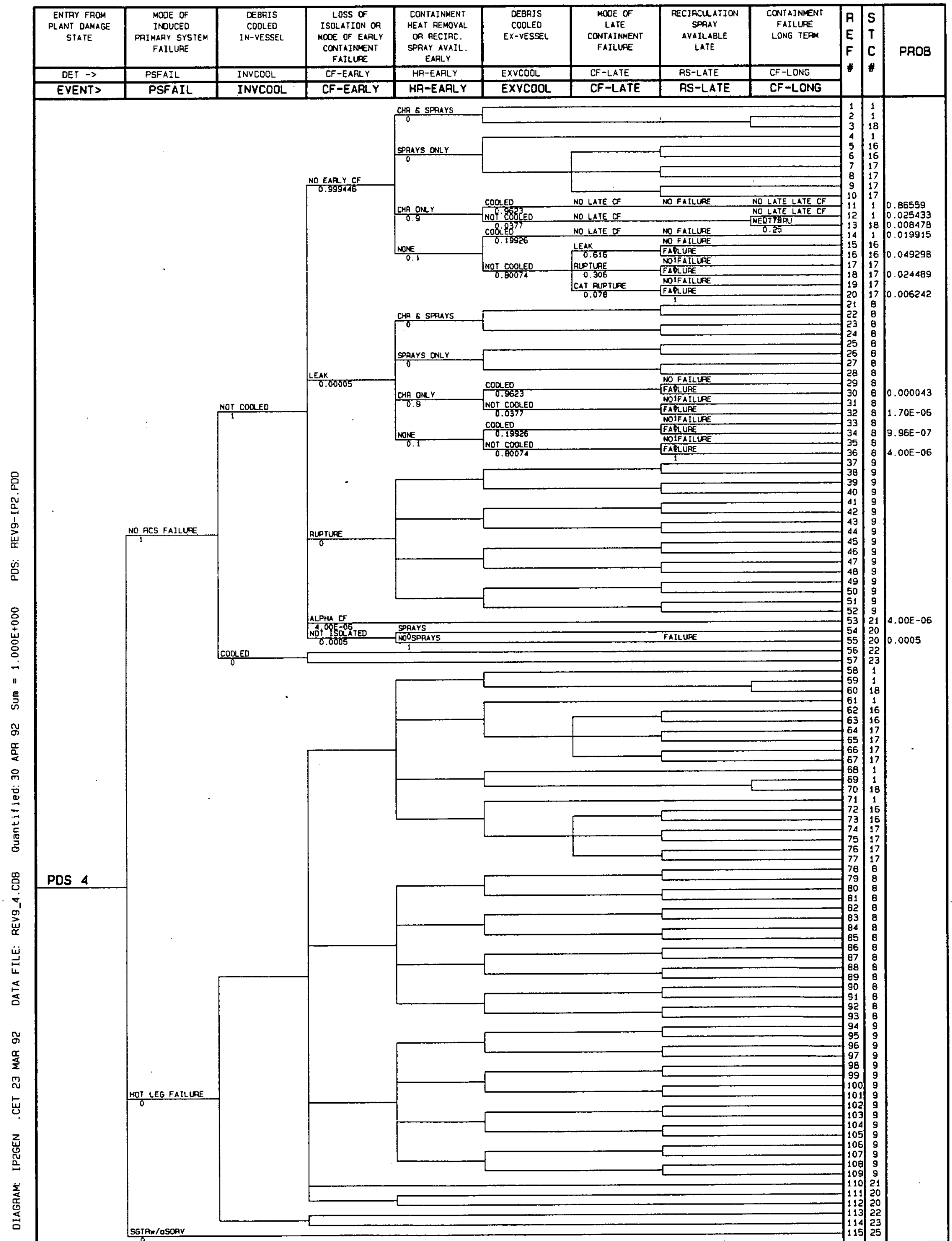


Figure 4.5-3

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 3



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115	25

Figure 4.5-4

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 4

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_5.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

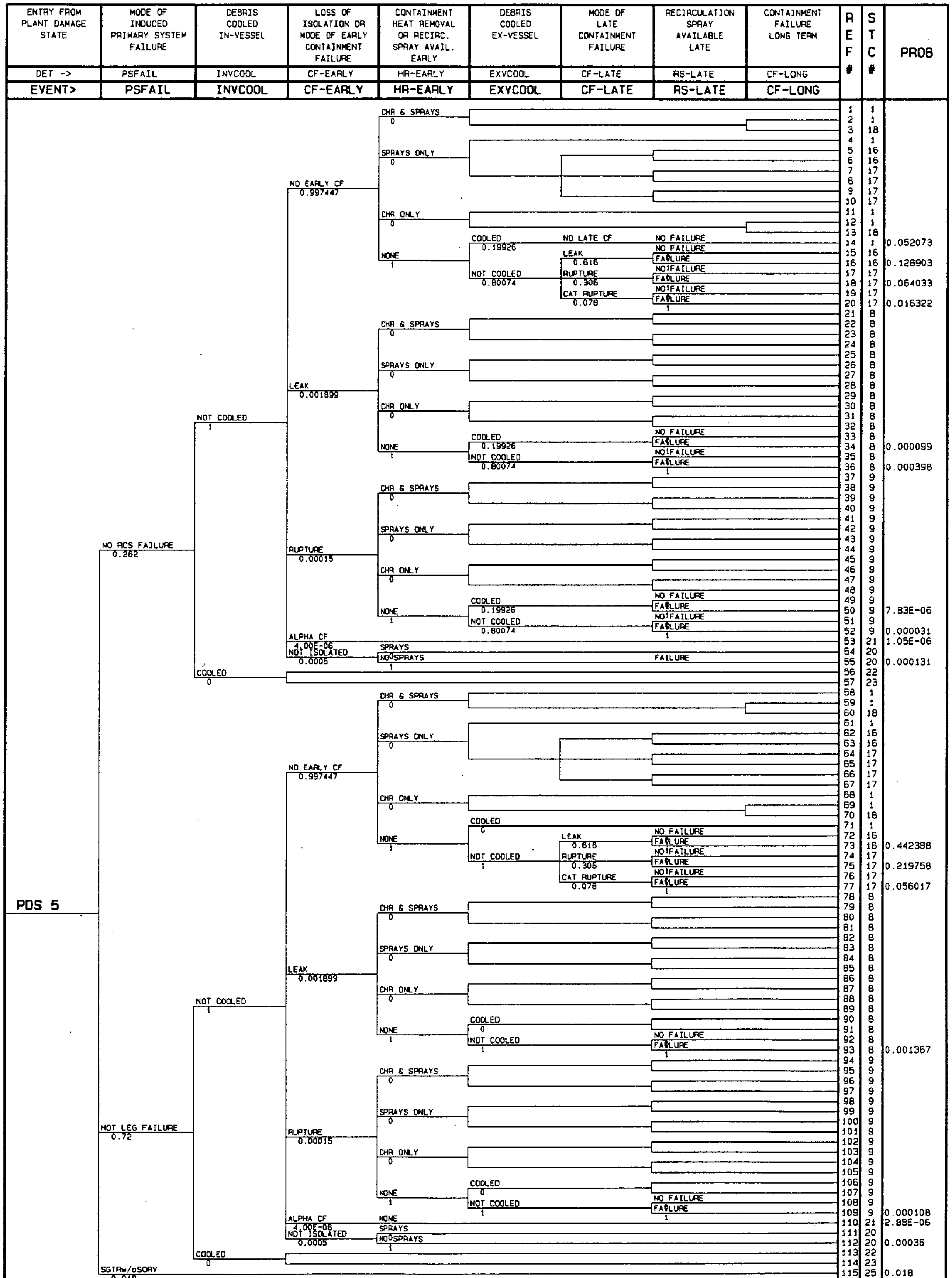


Figure 4.5-5

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 5

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_6.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

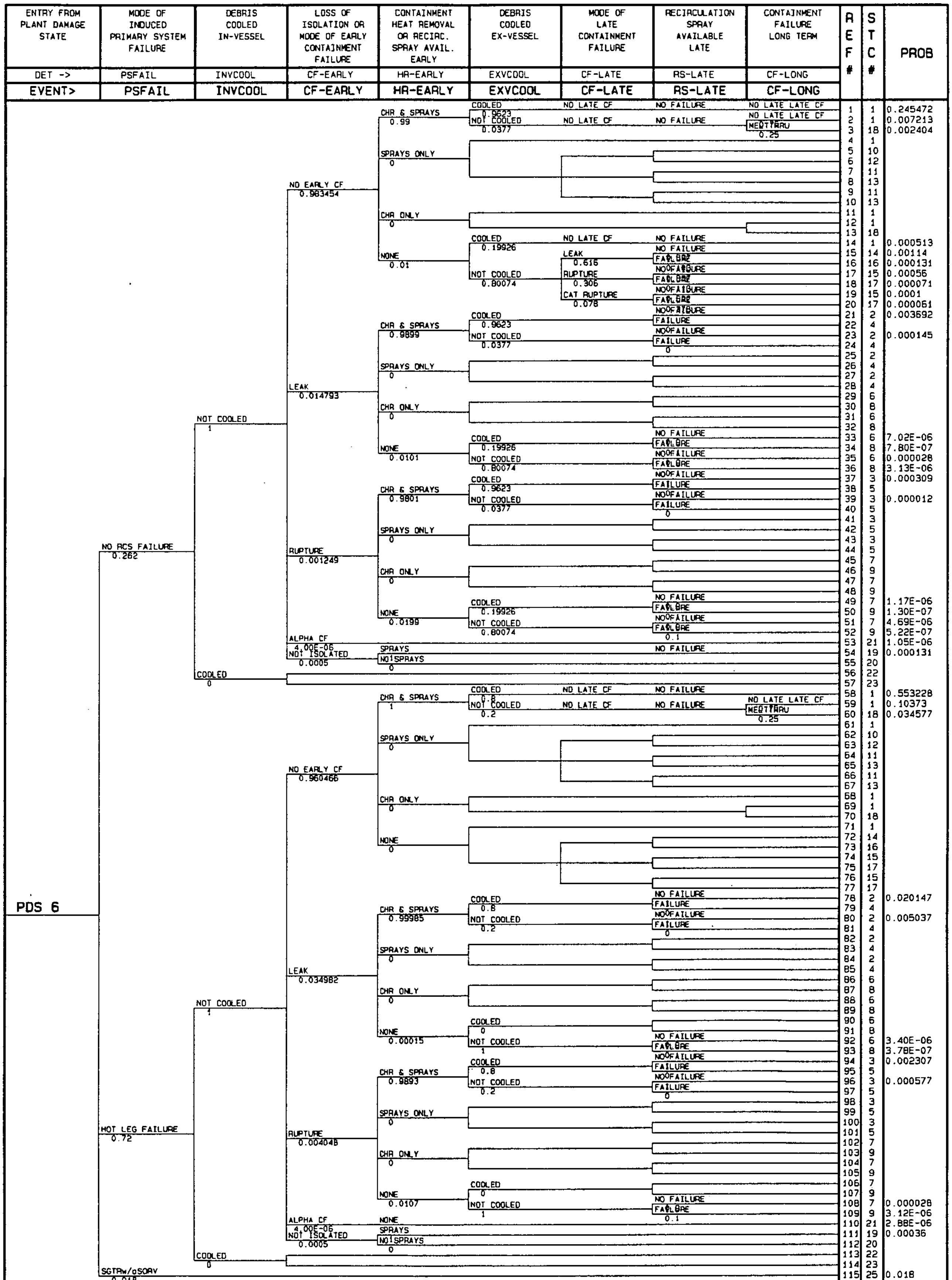


Figure 4.5-6

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 6

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_7.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

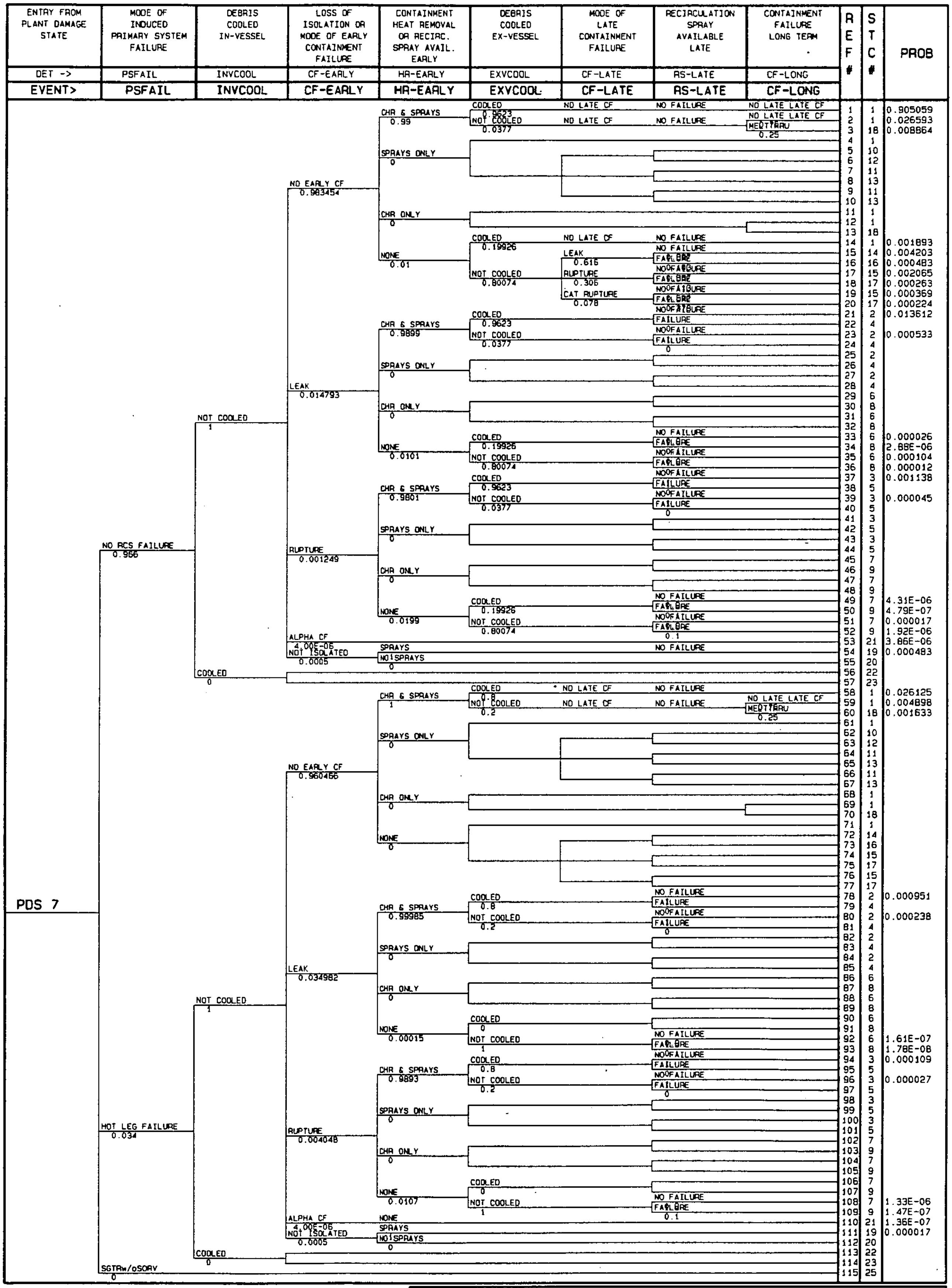


Figure 4.5-7

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 7

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_8.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

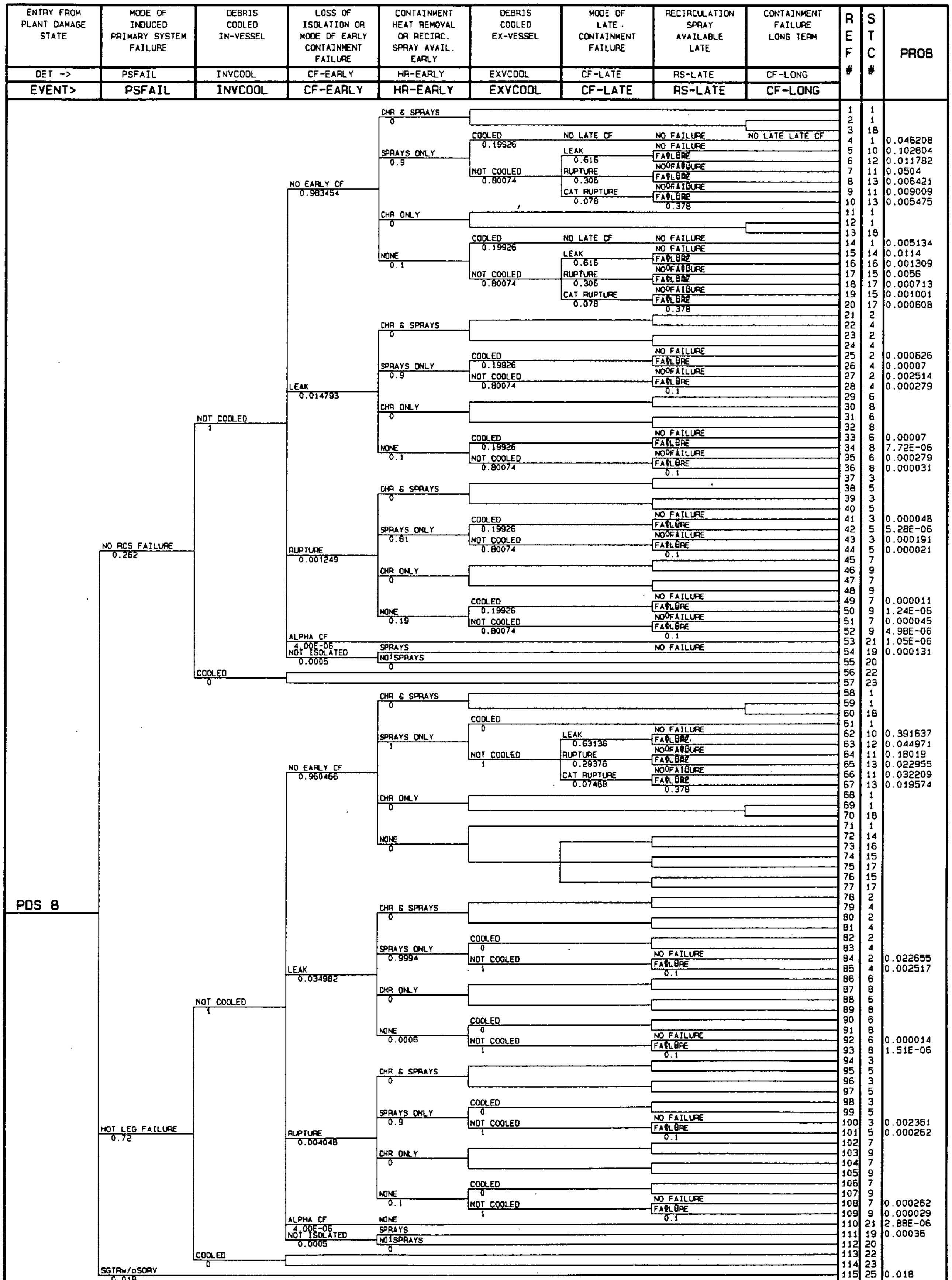


Figure 4.5-8

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 8

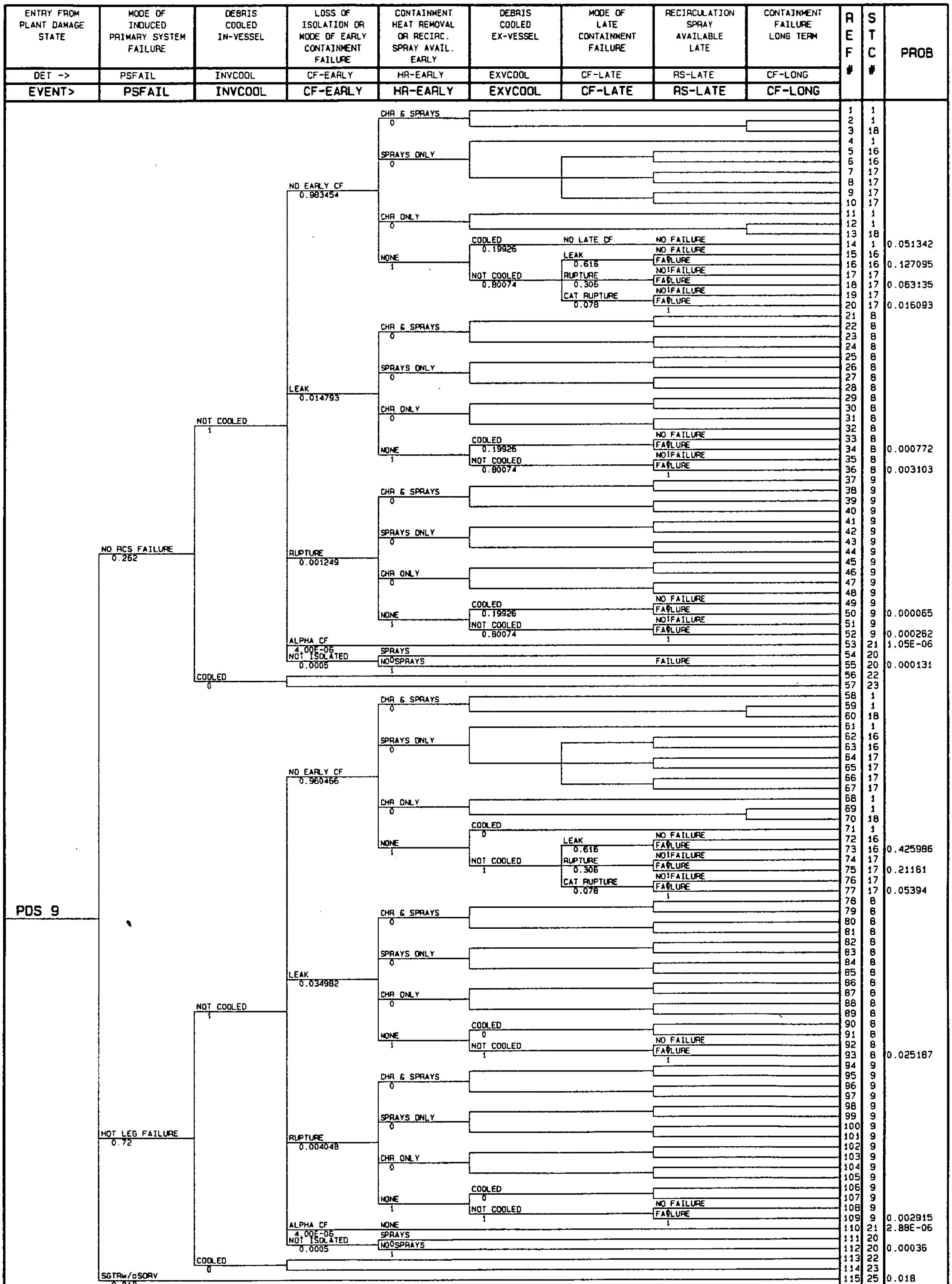


Figure 4.5-9

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 9

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_10.COB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

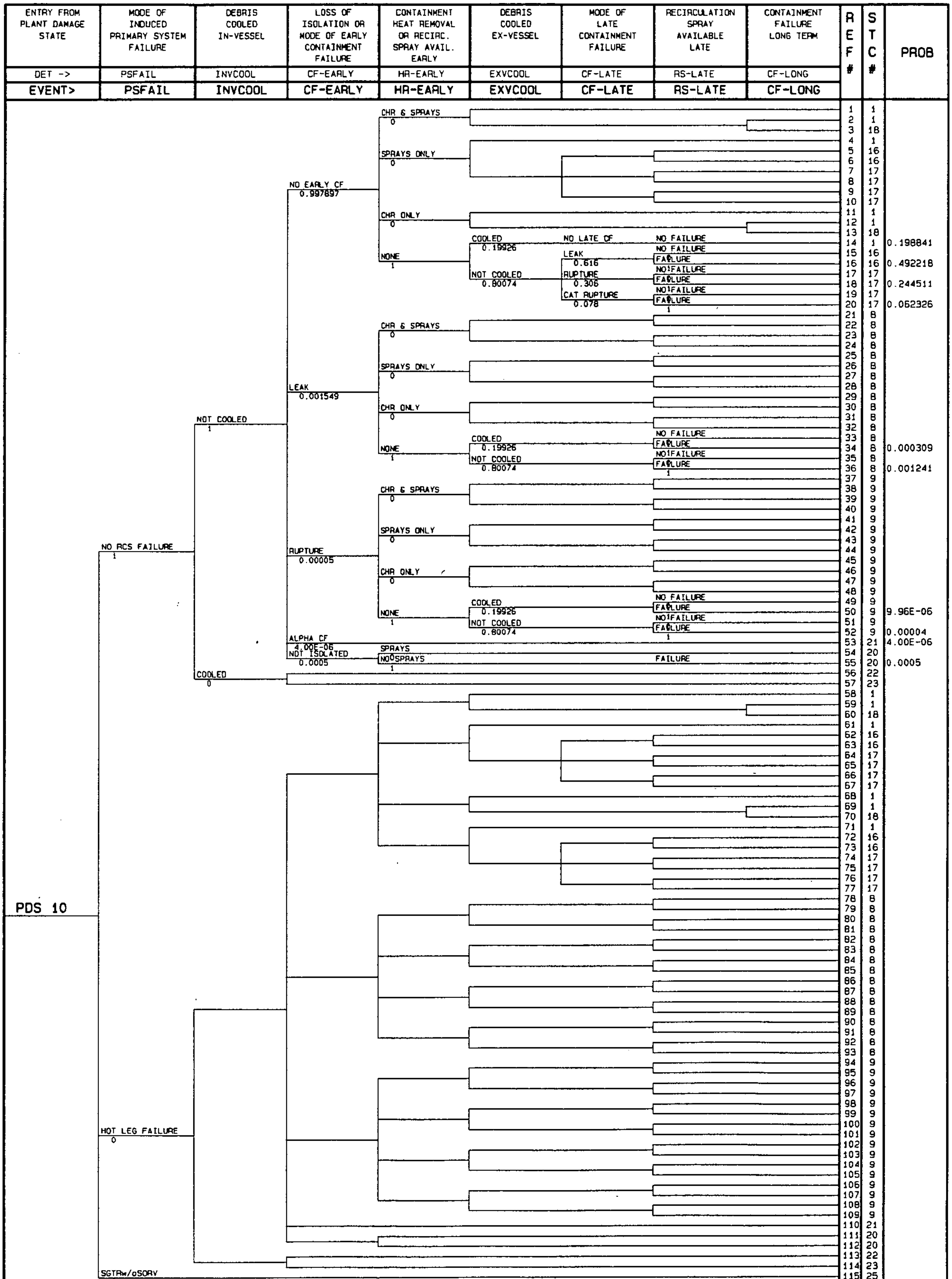


Figure 4.5-10

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 10

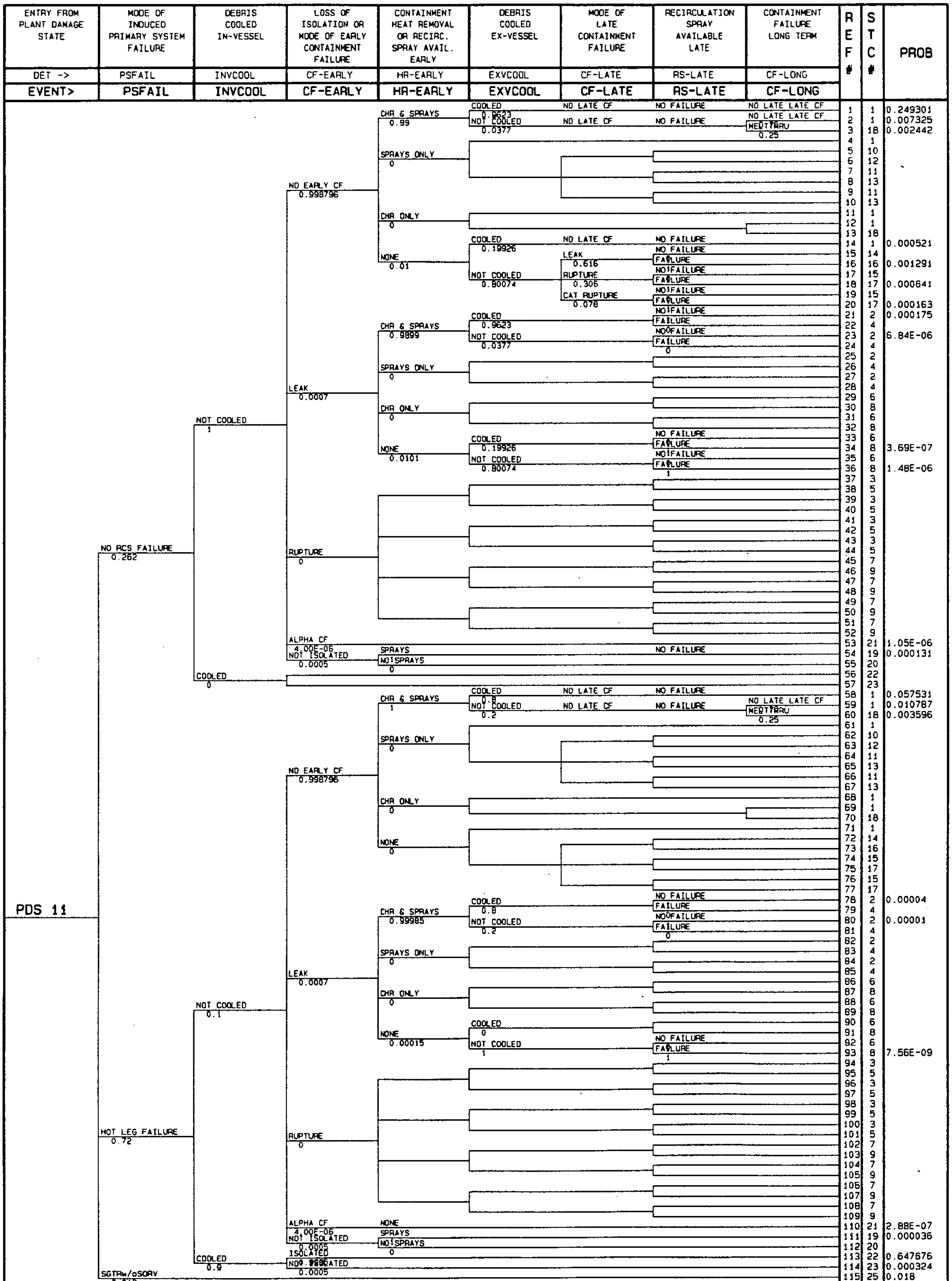


DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_11.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

Figure 4.5-11

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 11

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_12.COB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

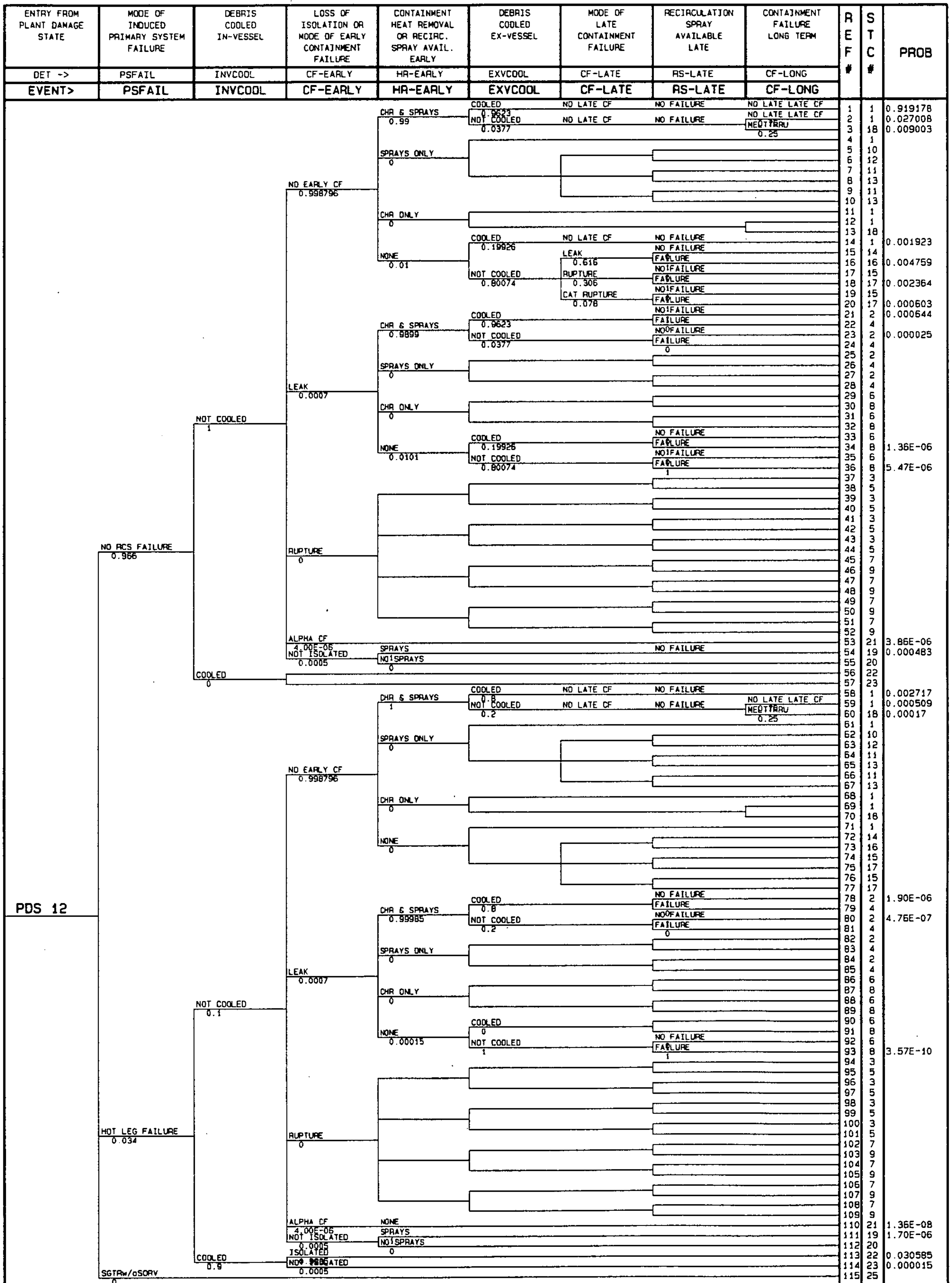


Figure 4.5-12

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 12

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_13.COB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

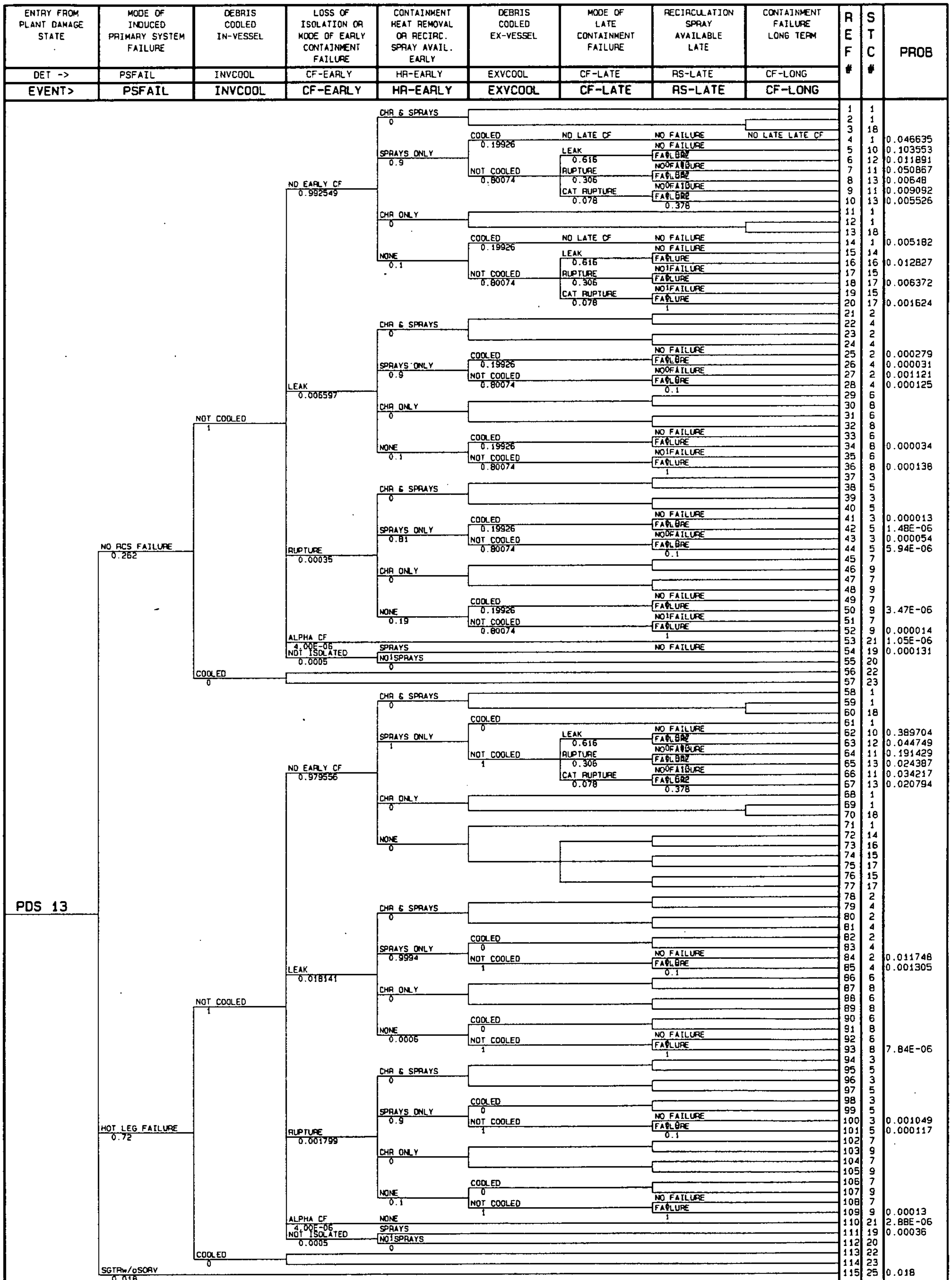


Figure 4.5-13

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 13

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_14.COB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

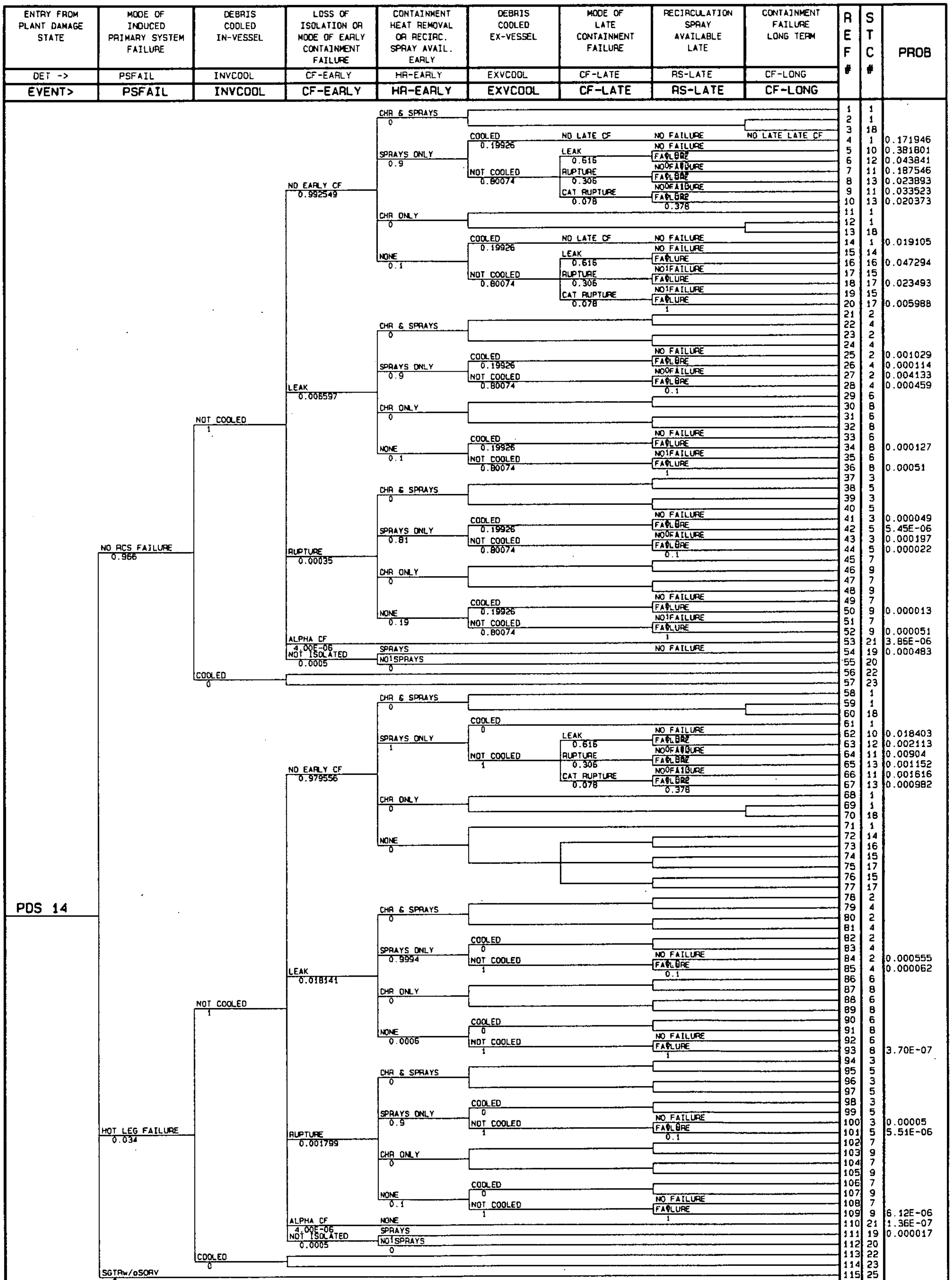


Figure 4.5-14

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 14

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_15.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

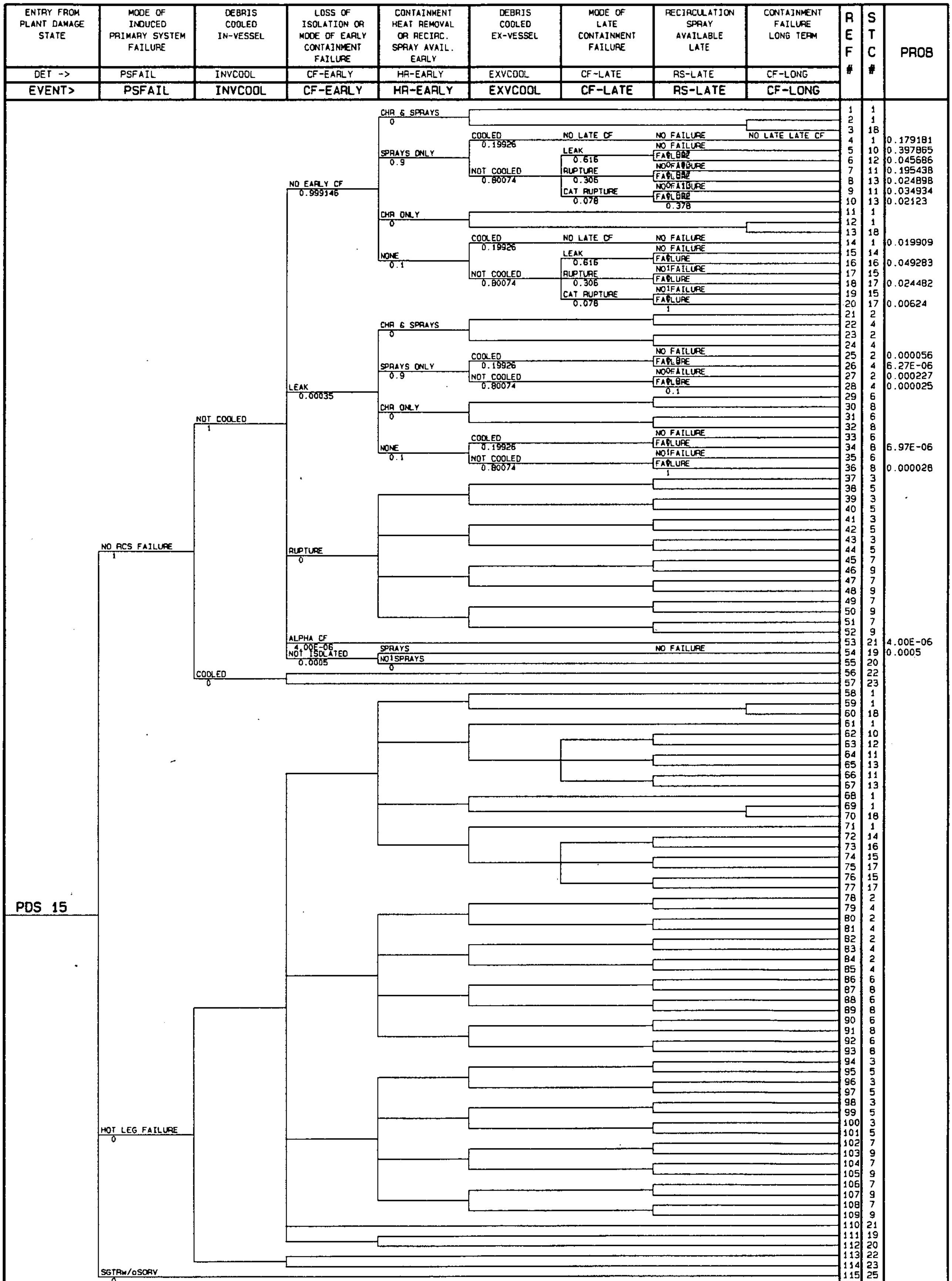


Figure 4.5-15

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 15

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_16.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

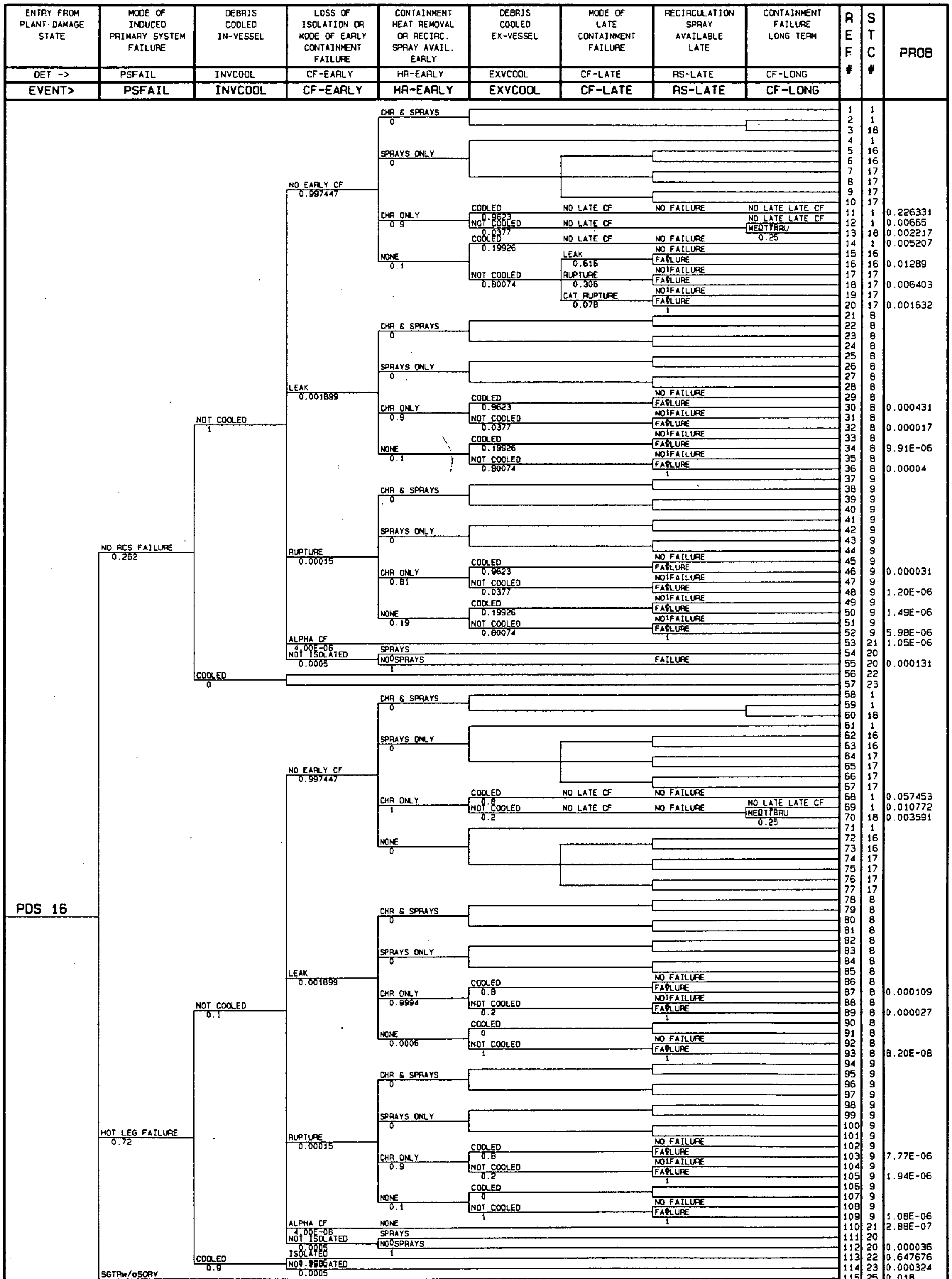


Figure 4.5-16

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 16

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_17.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

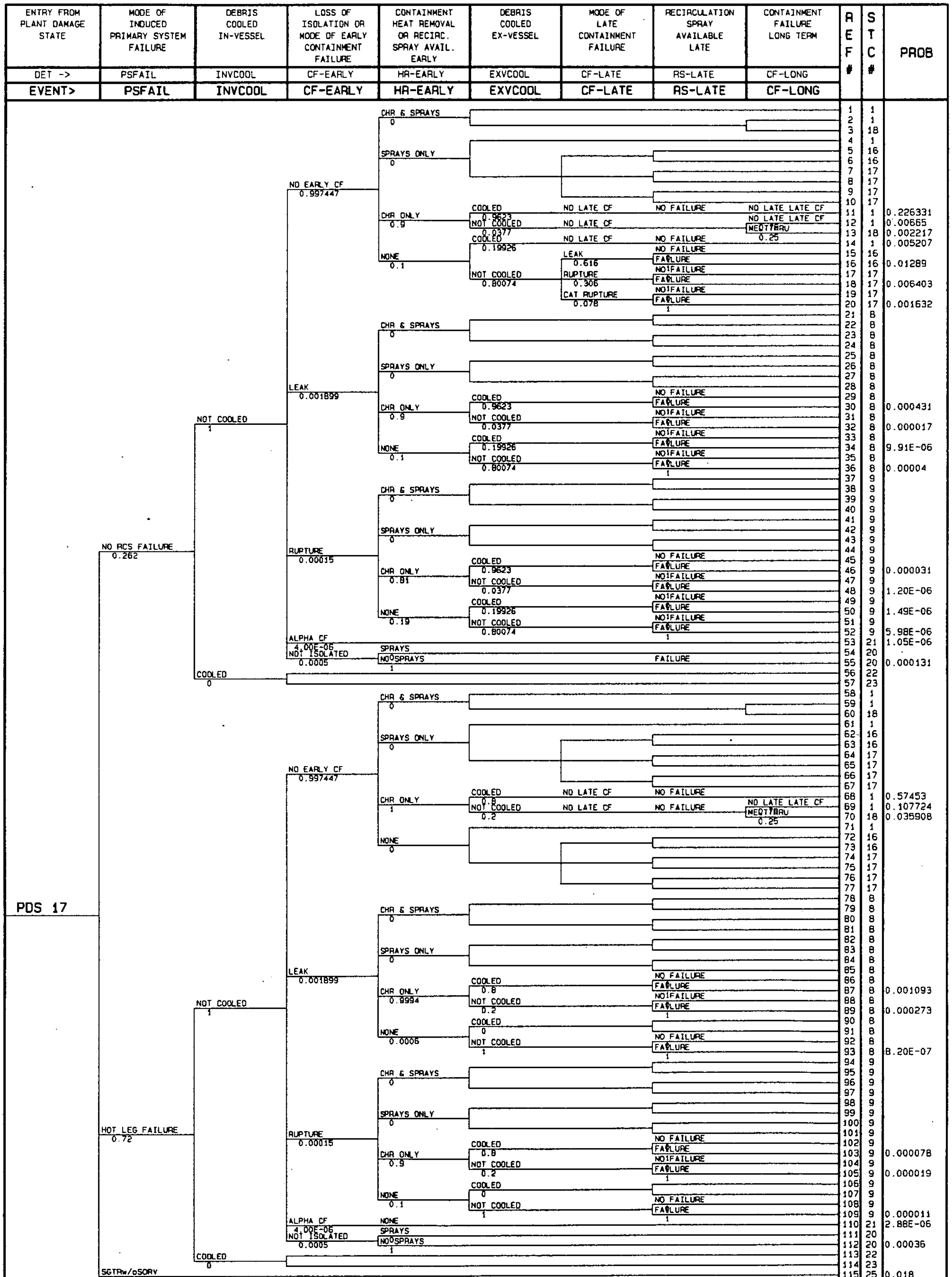


Figure 4.5-17

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 17

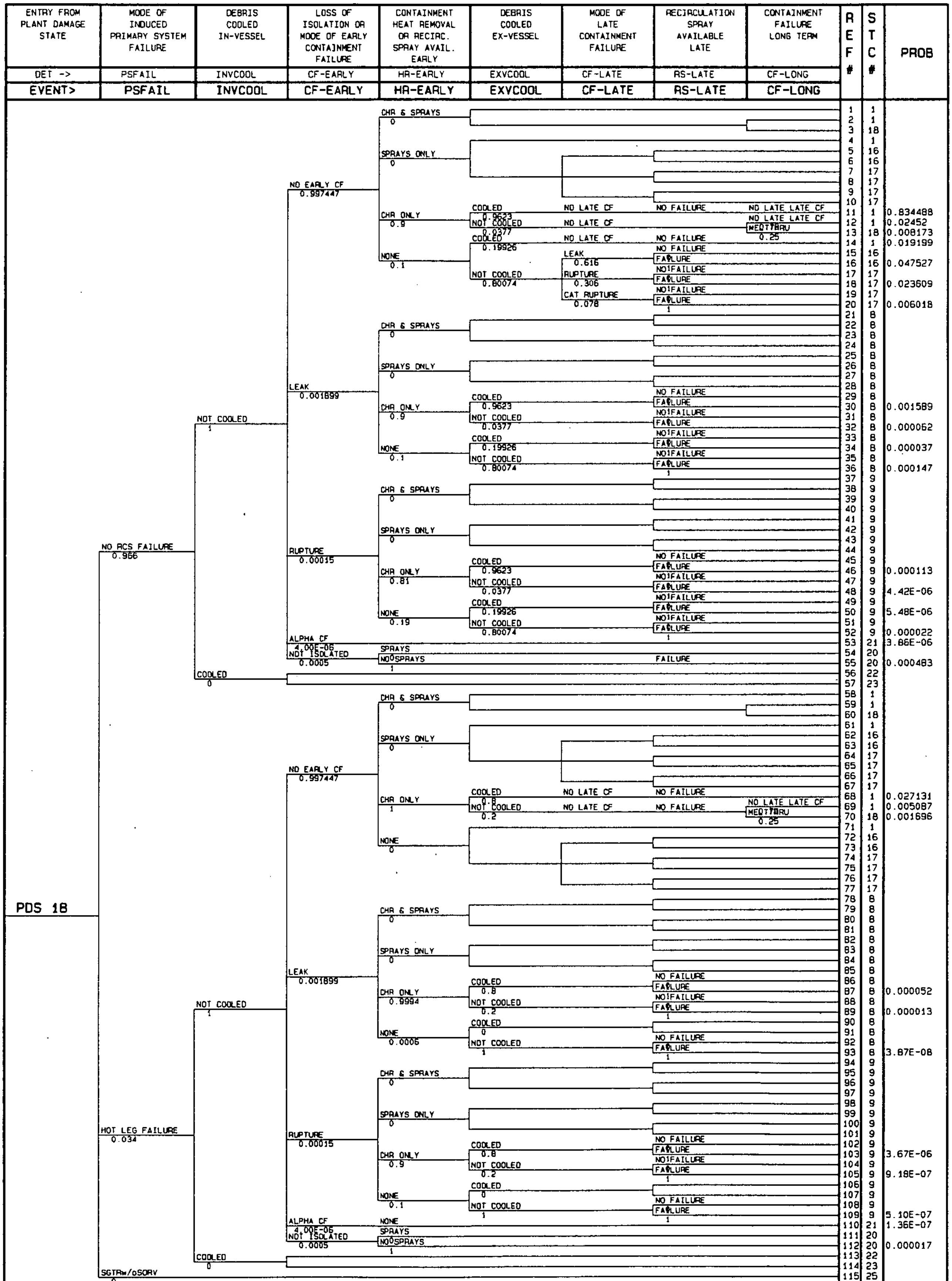


DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_18.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

Figure 4.5-18

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 18

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_19.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

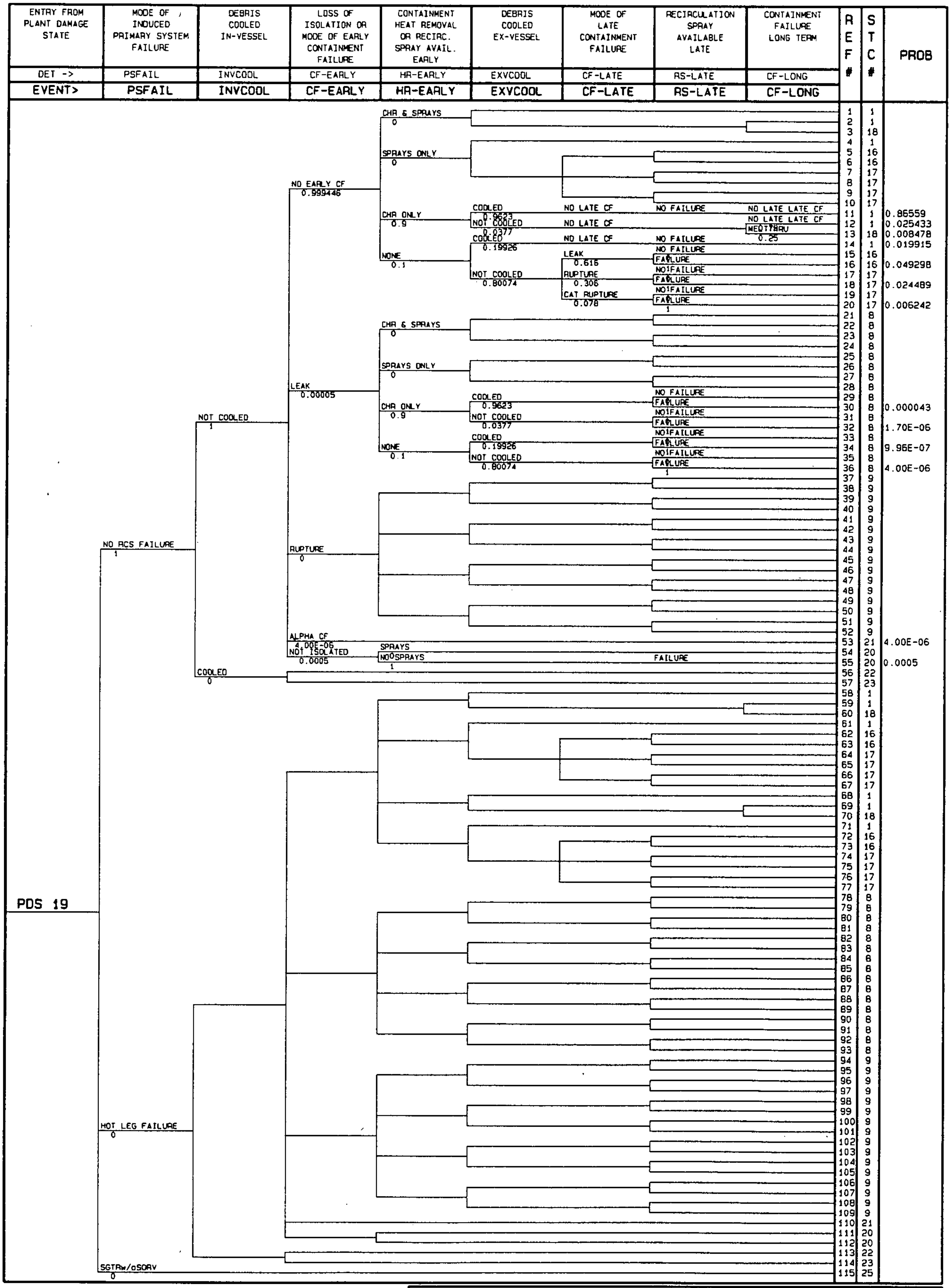


Figure 4.5-19

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 19

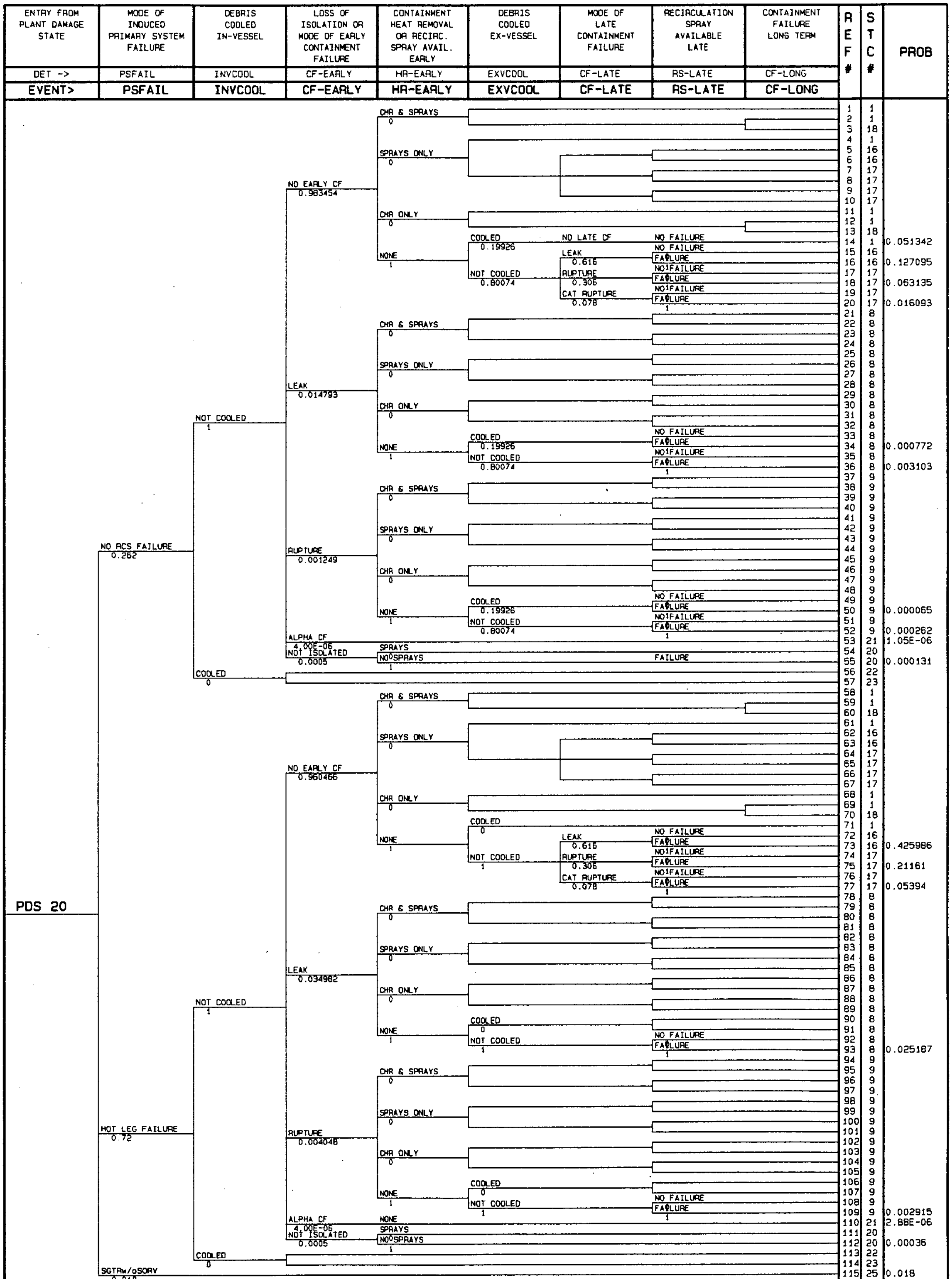


Figure 4.5-20

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 20

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_20.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

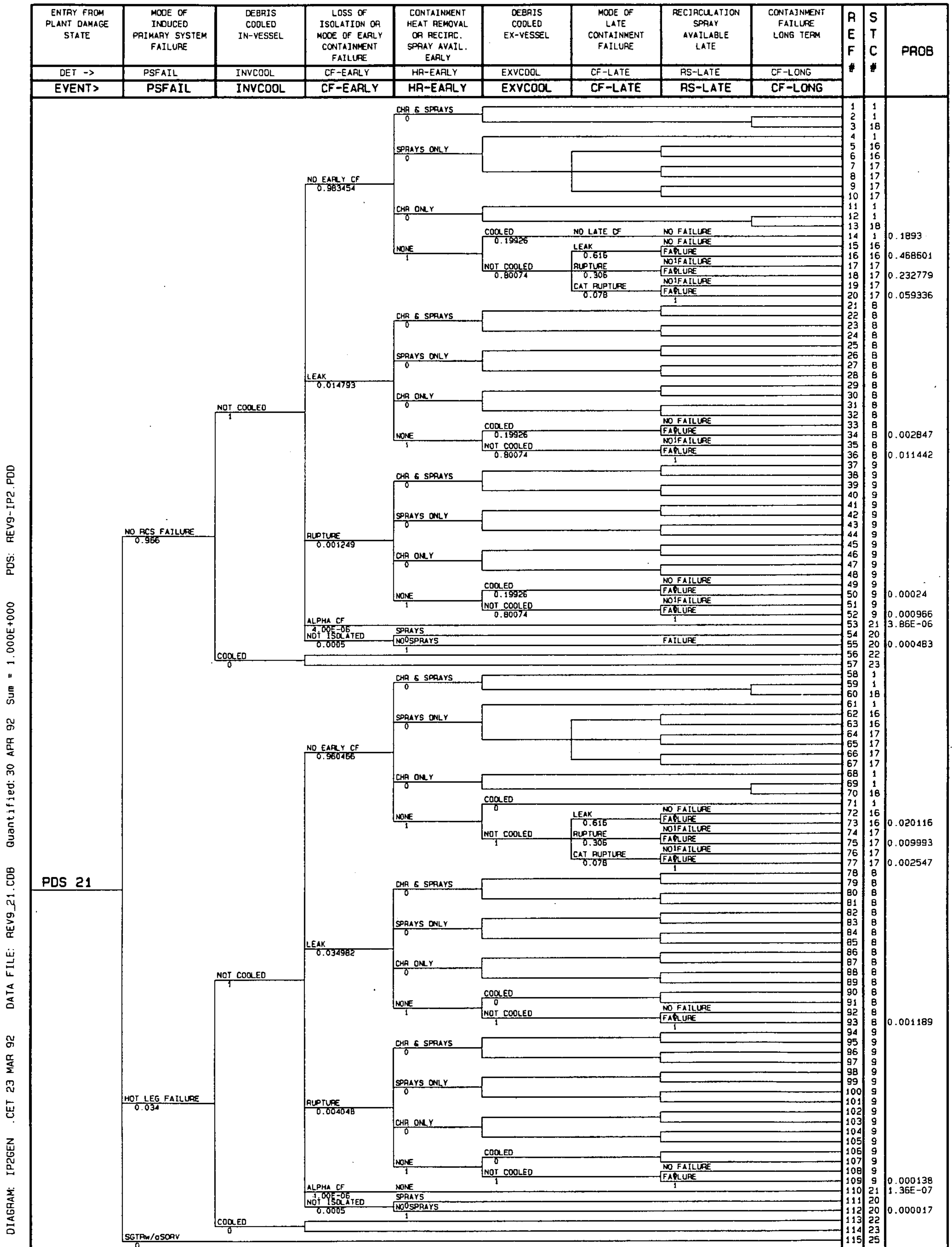


Figure 4.5-21

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 21

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_22.COB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

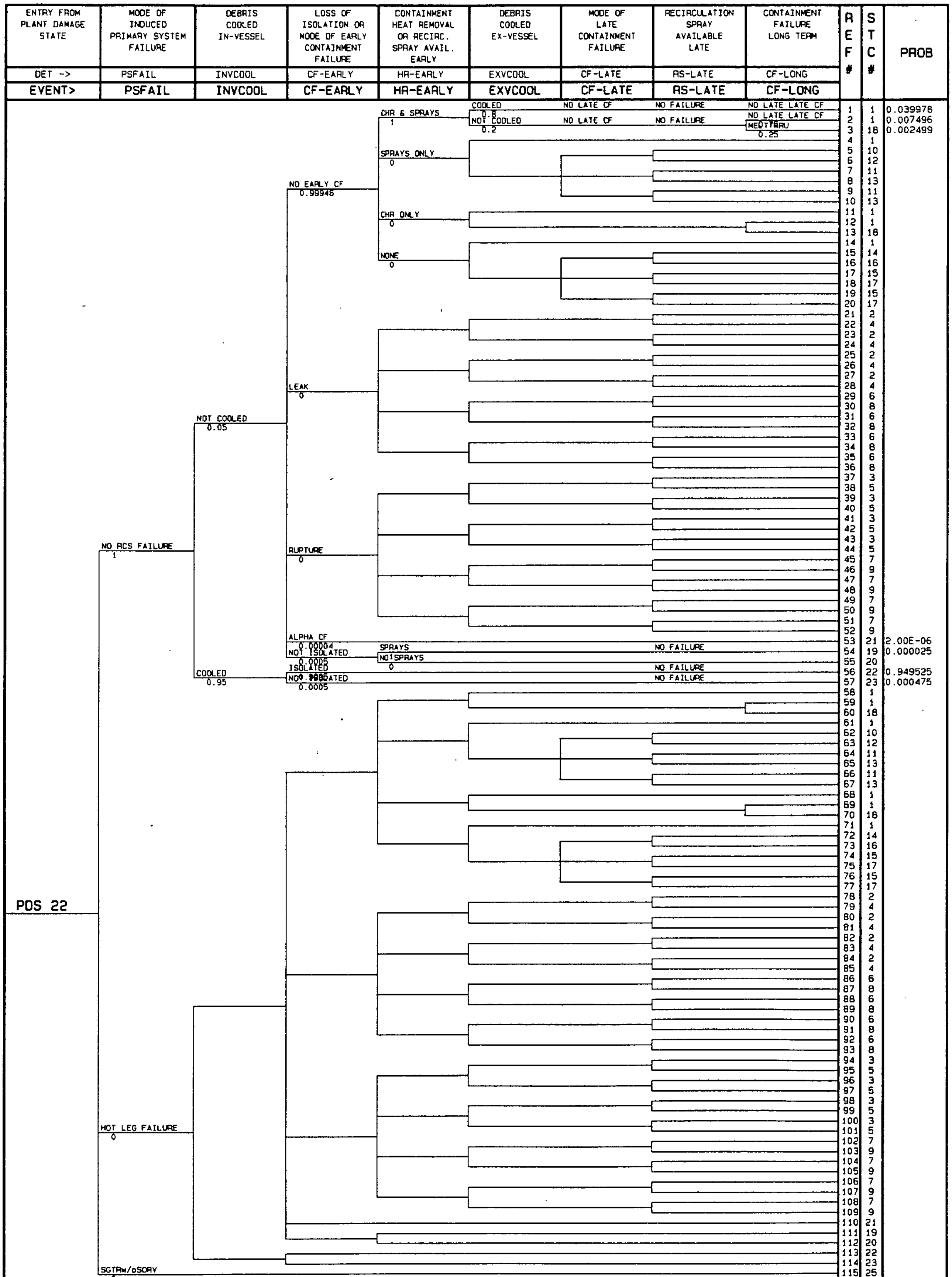


Figure 4.5-22

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 22

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_23.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

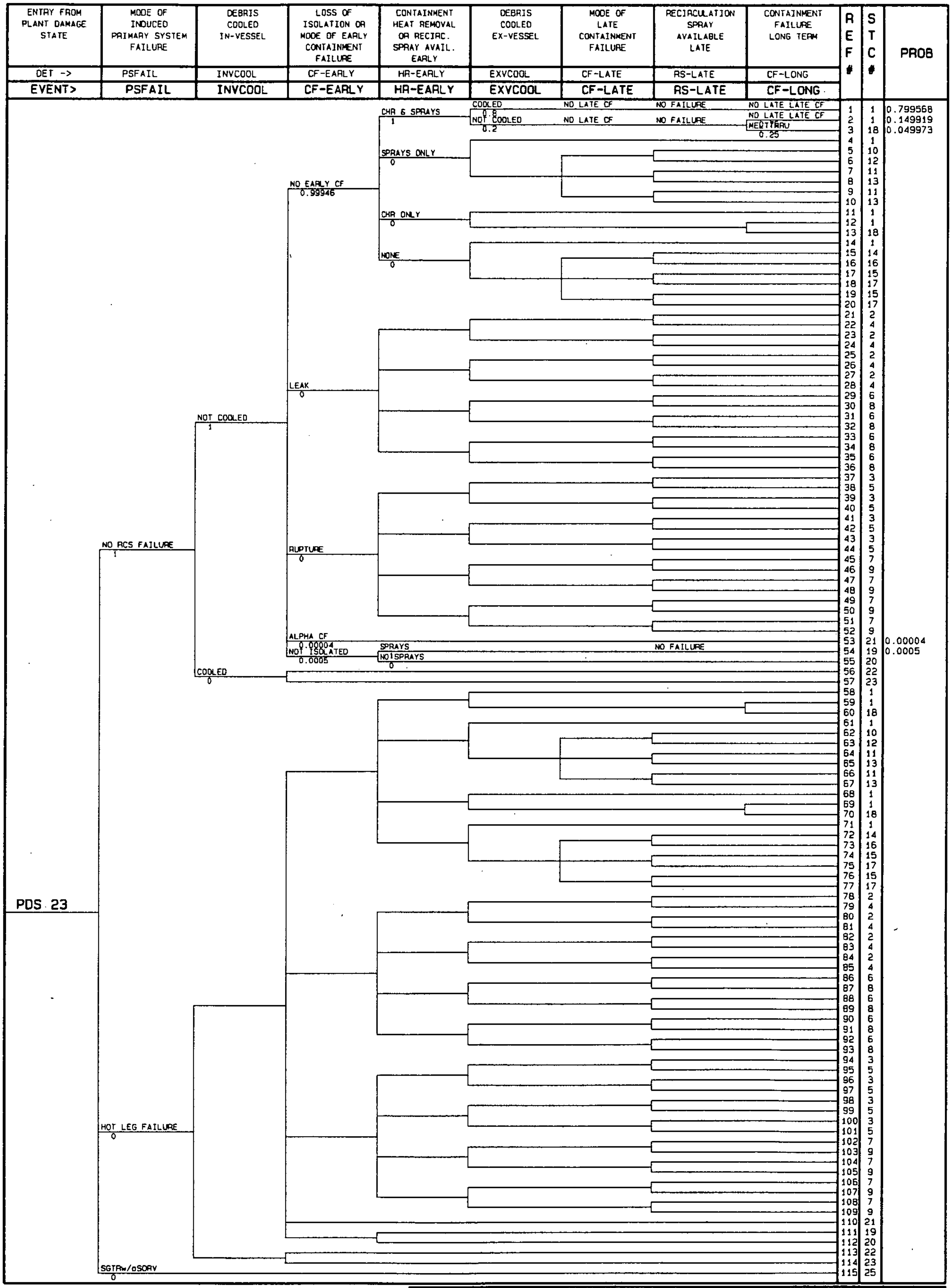


Figure 4.5-23

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 23

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_24.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

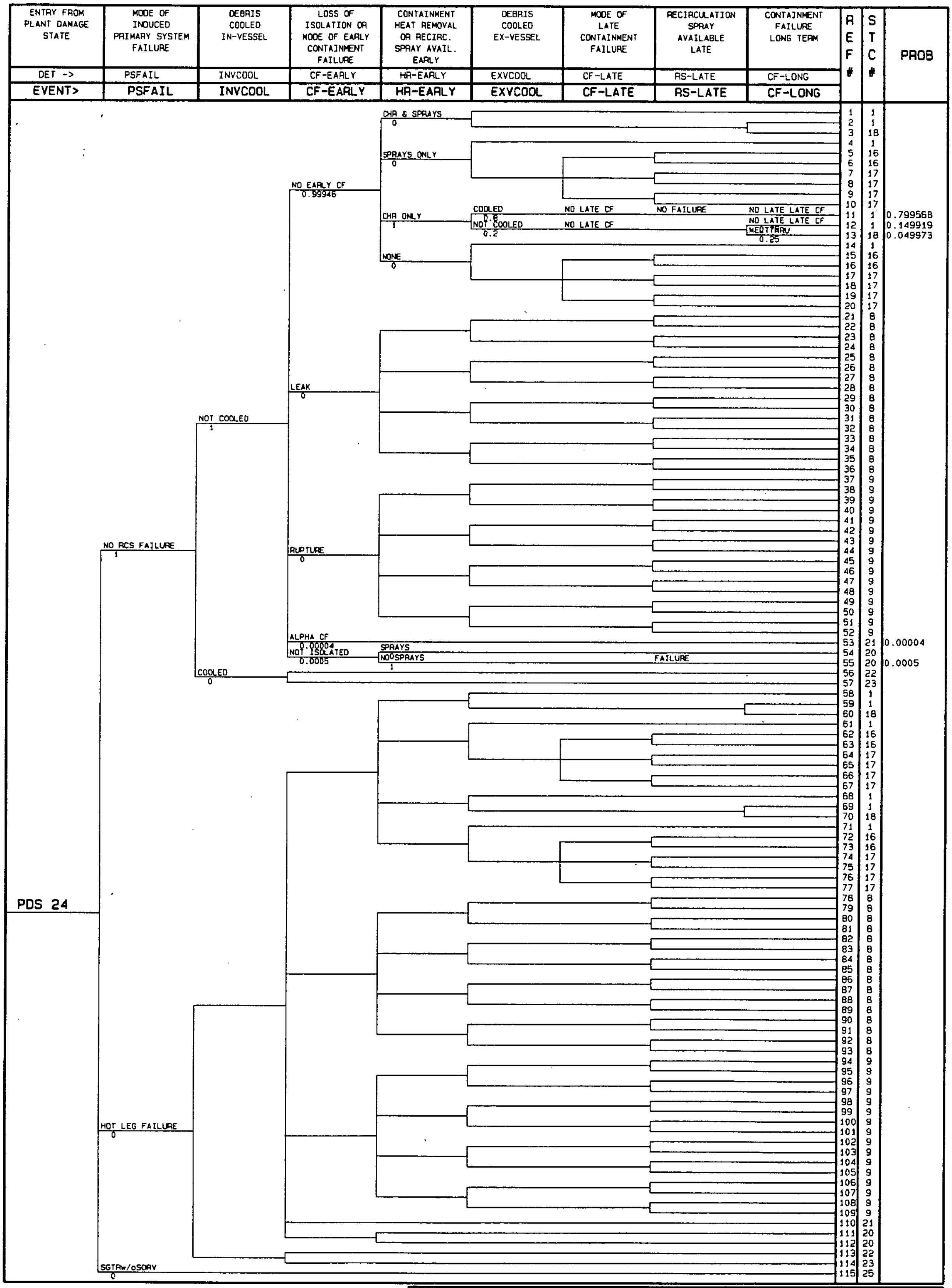


Figure 4.5-24

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 24

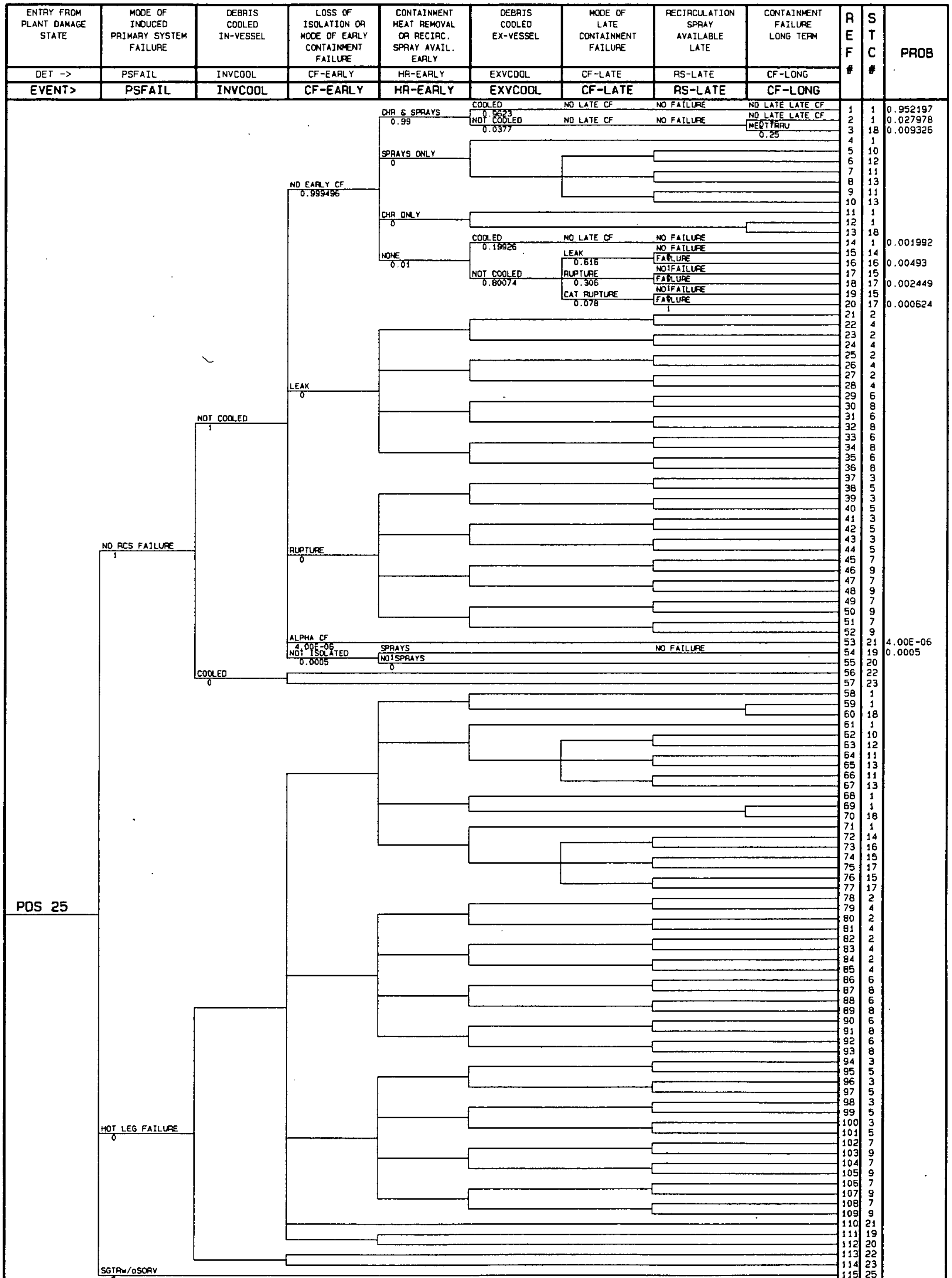


DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_25.CDB PDS 25 Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

Figure 4.5-25

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 25

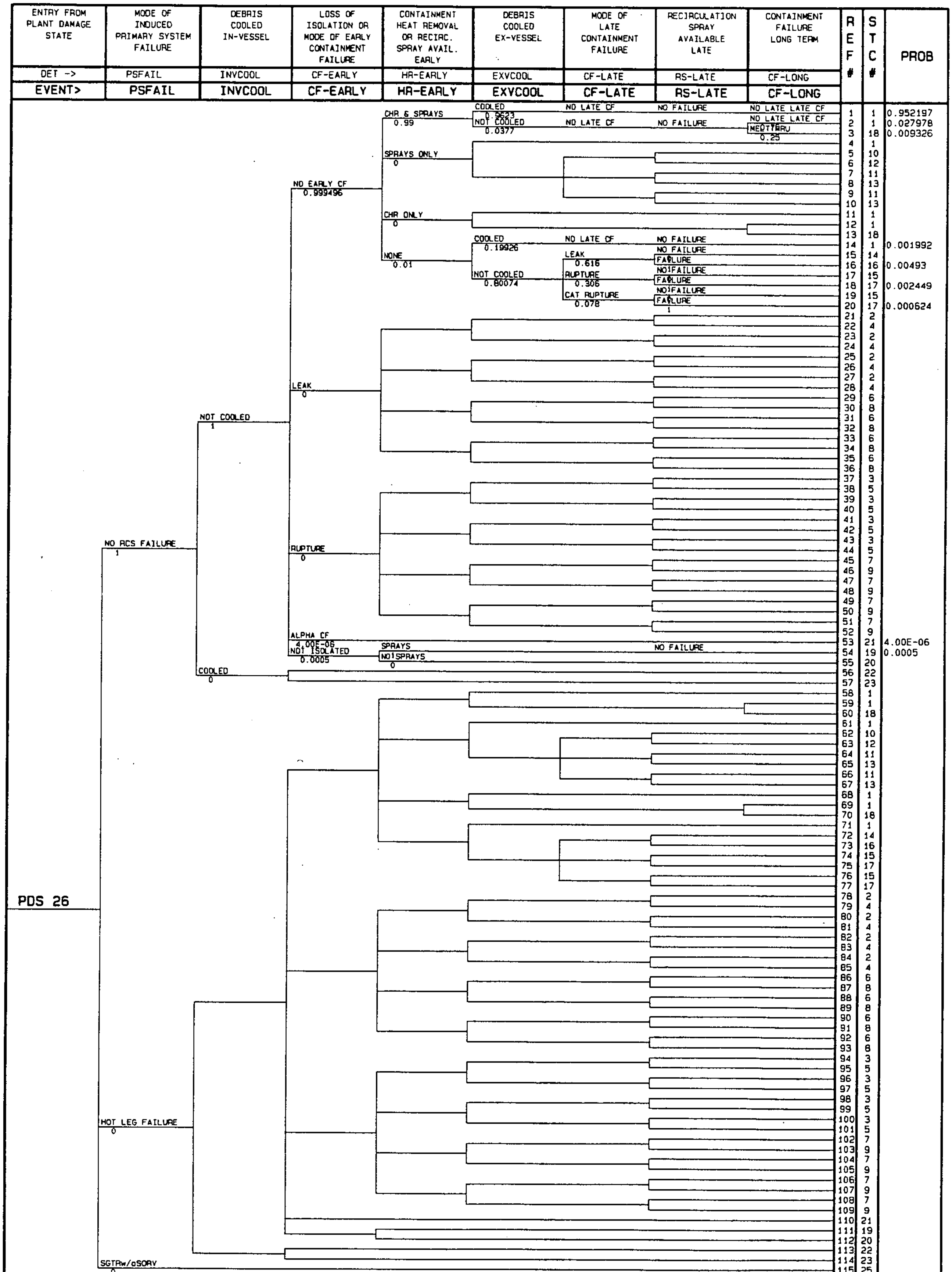


DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_26.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

Figure 4.5-26

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 26

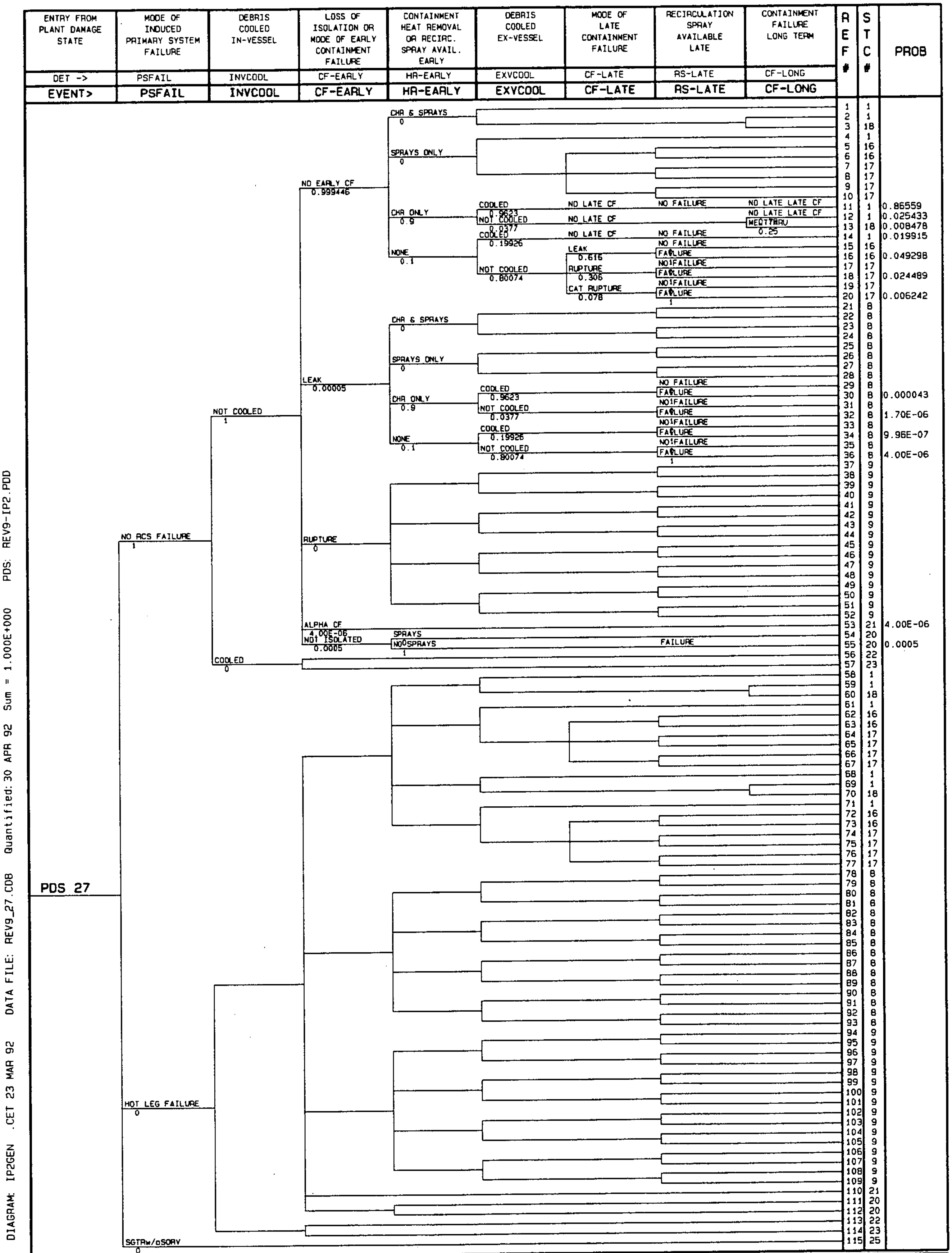


Figure 4.5-27

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 27

DIAGRAM: IP2GEN .CET 23 MAR 92 DATA FILE: REV9_28.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

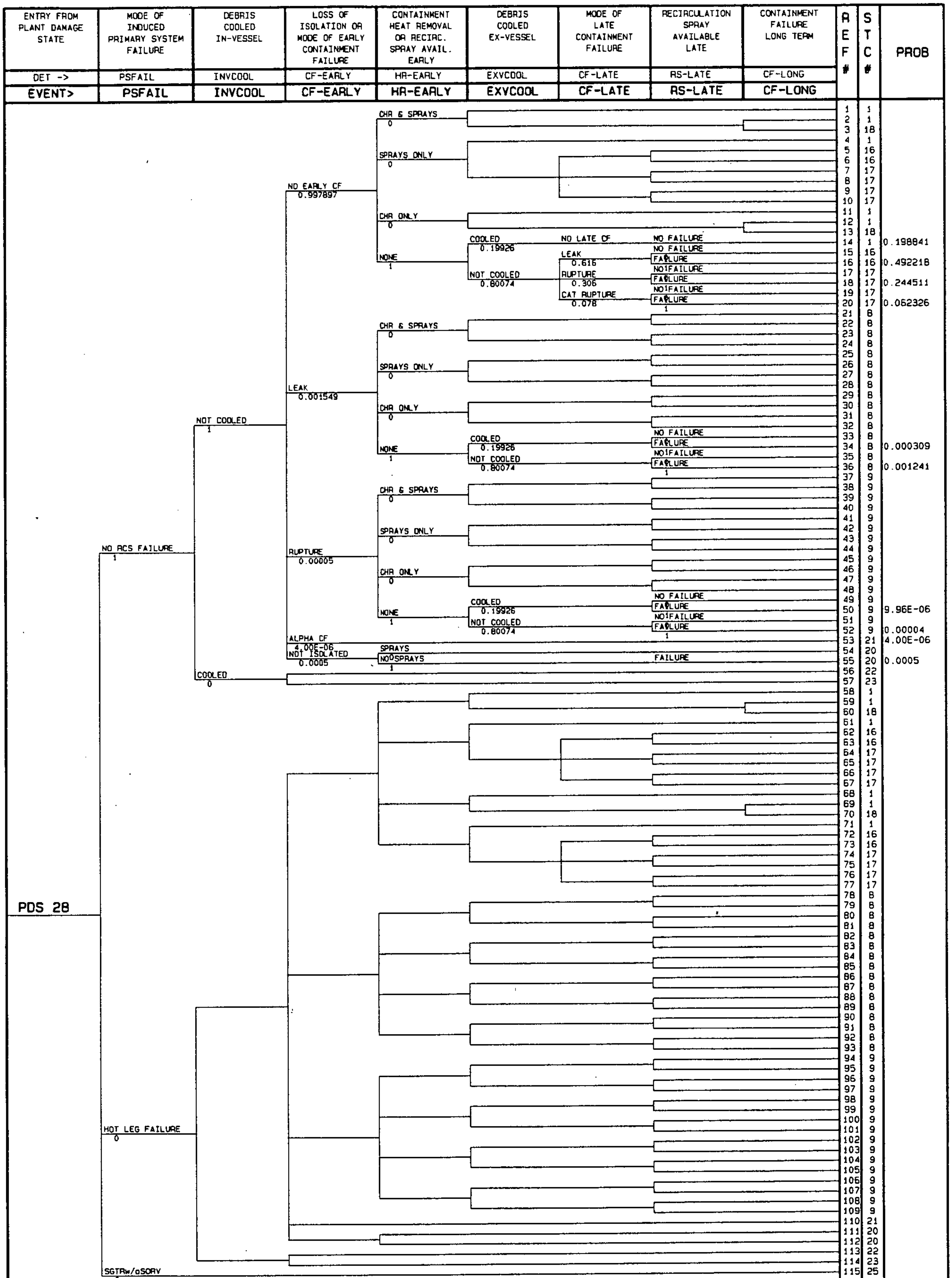


Figure 4.5-28

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

Containment Event Tree for PDS 28

DIAGRAM: IP2BRDGE.CET 31 DEC 91 DATA FILE: REV9_29.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

ENTRY FROM PLANT DAMAGE STATE	BYPASS OR MODE OF INDUCED PRIMARY SYSTEM FAILURE	REF #	STC #	PROB
DET ->	PSFAIL			
EVENT>	PSFAIL			
PDS 29	BYPASS	1	24	1.0

Figure 4.5-29

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA
"BRIDGE TREE" FOR BYPASS SEQUENCE TYPES
Containment Event Tree for PDS 29

ENTRY FROM PLANT DAMAGE STATE	BYPASS OR MODE OF INDUCED PRIMARY SYSTEM FAILURE	REF #	STC #	PROB
DET ->	PSFAIL			
EVENT>	PSFAIL			
PDS 30	BYPASS	1	25	1.0

DIAGRAM: IP2BRDGE.CET 31 DEC 91 DATA FILE: REV9_30.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

Figure 4.5-30

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

"BRIDGE TREE" FOR BYPASS SEQUENCE TYPES
Containment Event Tree for PDS 30

DIAGRAM: IP2BRDGE.CET 31 DEC 91 DATA FILE: REV9_31.CDB Quantified: 30 APR 92 Sum = 1.000E+000 PDS: REV9-IP2.PDD

ENTRY FROM PLANT DAMAGE STATE	BYPASS OR MODE OF INDUCED PRIMARY SYSTEM FAILURE	REF #	STC #	PROB
DET ->	PSFAIL			
EVENT>	PSFAIL			
PDS 31	BYPASS	1	26	1.0

Figure 4.5-31

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA
"BRIDGE TREE" FOR BYPASS SEQUENCE TYPES
Containment Event Tree for PDS 31

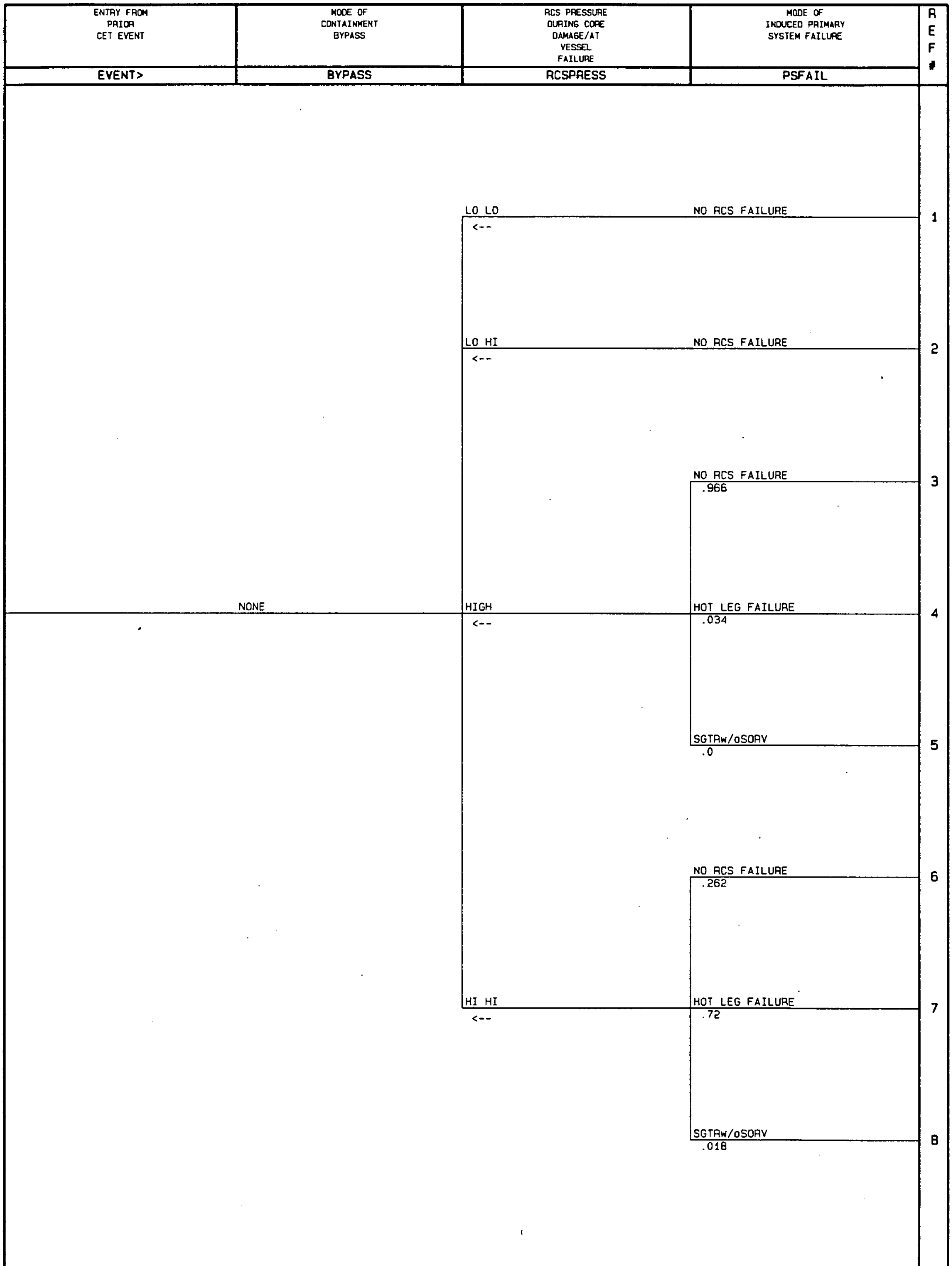


DIAGRAM: PSFAIL.DET 22 MAR 92

Figure 4.6-1

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

MODE OF INDUCED PRIMARY SYSTEM FAILURE
DECOMPOSITION EVENT TREE

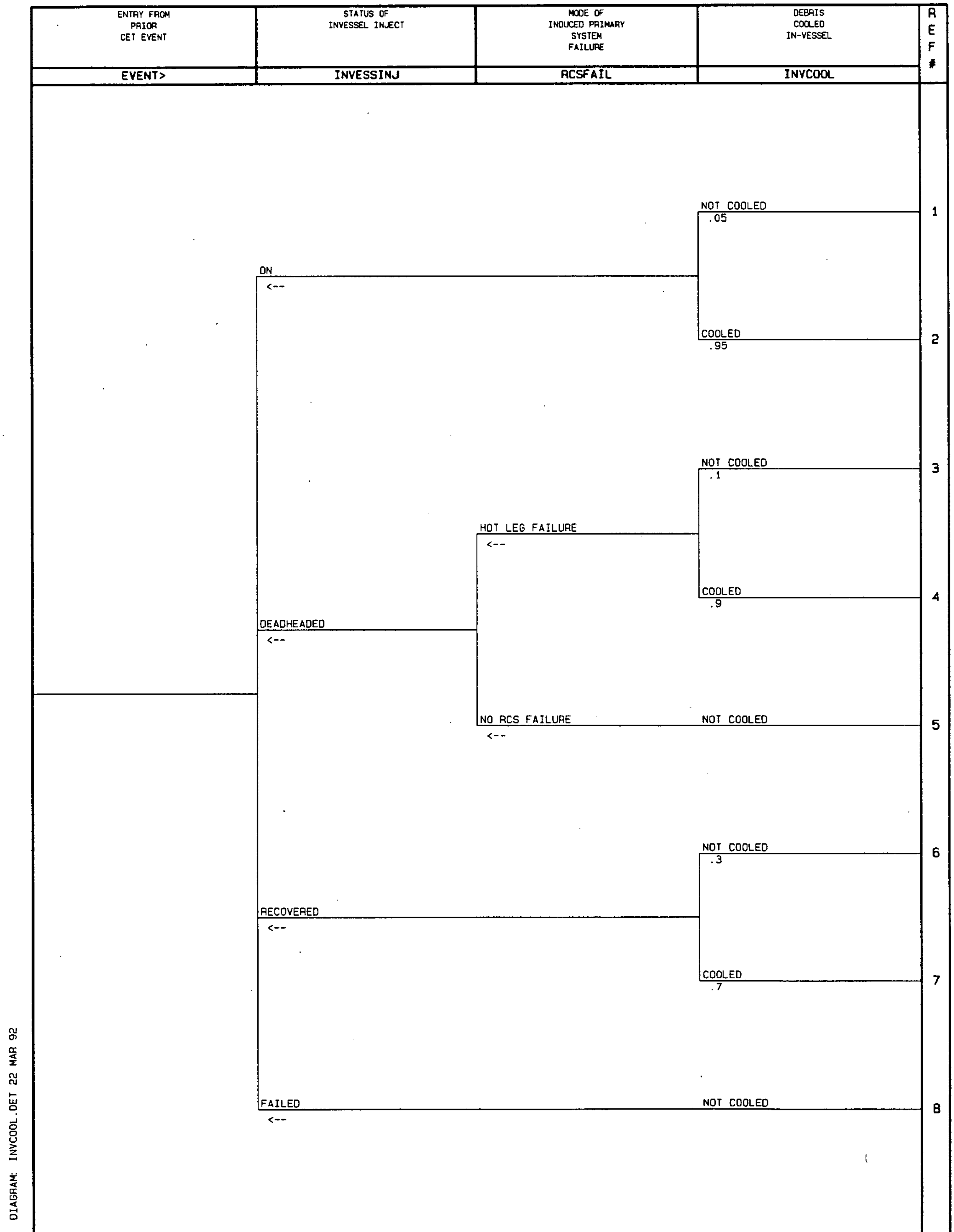
REV 0

FIGURE 4.6-1 (continued)

LOGIC RULES from PSFAIL .DET

RULE <RCSPRESS >

IF P:RCSPRESS = LO LO;
THEN LO LO;
IF P:RCSPRESS = LO HI;
THEN LO HI;
IF P:RCSPRESS = HIGH;
THEN HIGH;
IF P:RCSPRESS = HI HI;
THEN HI HI;



CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA
DEBRIS COOLED IN-VESSEL
DECOMPOSITION EVENT TREE
REV 0

Figure 4.6-2

Figure 4.6-2 (continued)

LOGIC RULES from INVCOOL .DET

RULE <INVESSINJ>

IF P:INVESSINJ = ON;
THEN ON;
IF P:INVESSINJ = DEADHEADED;
THEN DEADHEADED;
IF P:INVESSINJ = RECOVERED;
THEN RECOVERED;
IF P:INVESSINJ = FAILED;
THEN FAILED;

RULE <RCSFAIL >

IF C:PSFAIL = NO RCS FAILURE;
THEN NO RCS FAILURE;
IF C:PSFAIL = HOT LEG FAILURE;
THEN HOT LEG FAILURE;
IF C:PSFAIL = SGTRw/oSORV;
THEN NO RCS FAILURE;

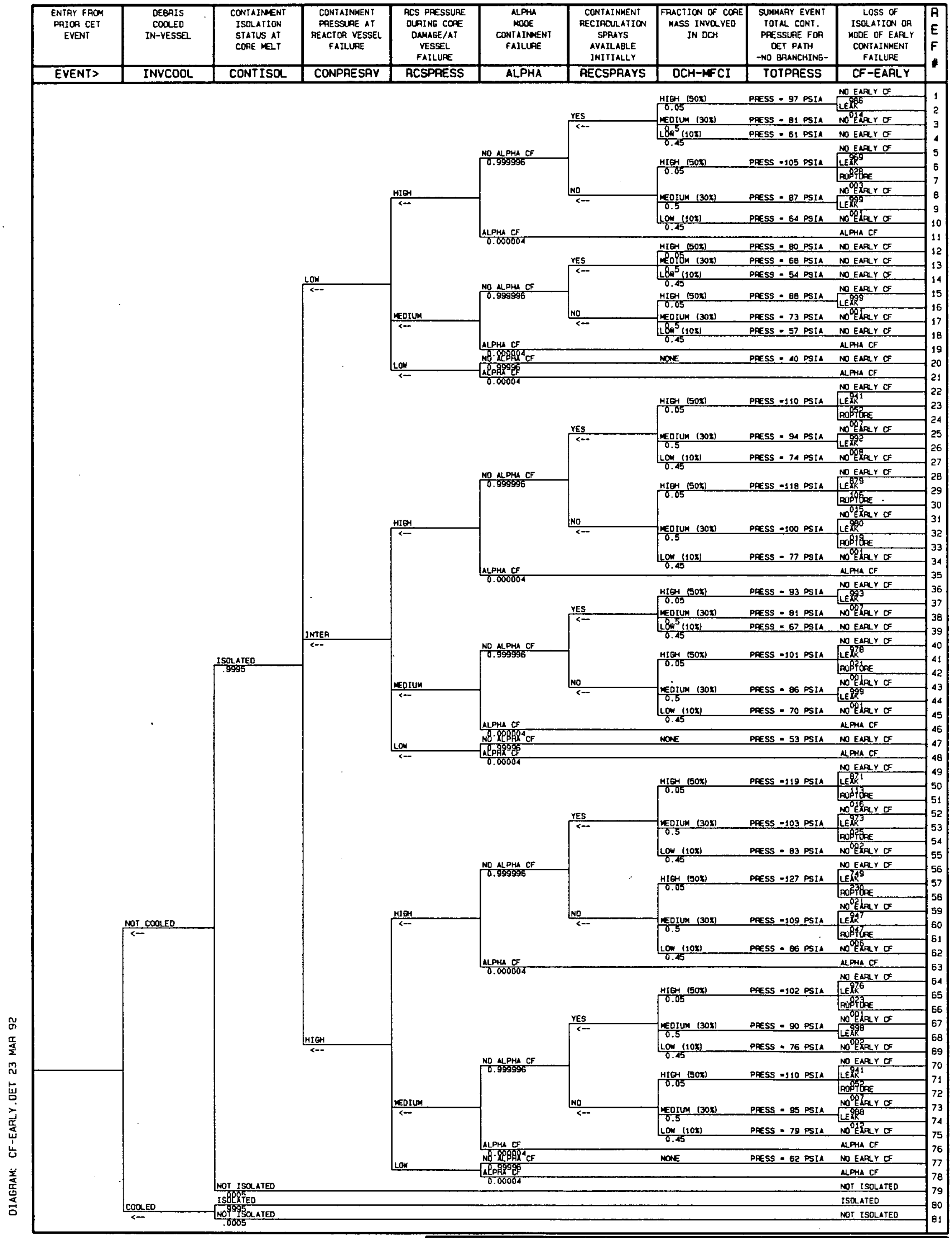


Figure 4.6-3

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

LOSS OF ISOLATION OR MODE OF EARLY CONTAINMENT FAILURE
DECOMPOSITION EVENT TREE

REV. 1

FIGURE 4.6-3 (continued)
LOGIC RULES from CF-EARLY.DET

RULE <INVCOOL >

IF C:INVCOOL = NOT COOLED;
THEN NOT COOLED;
IF C:INVCOOL = COOLED;
THEN COOLED;

RULE <CONPRESRV>

IF P:TRANLOCA ≠ SBO * P:CNHEATREM = YES;
IF P:TRANLOCA = SBO * P:POWRECOV = PRIOR RV FAIL;
THEN LOW;
IF P:TRANLOCA=SBO*P:POWRECOV≠PRIOR RV FAIL*C:PSFAIL=HOT LEG FAILURE;
IF P:TRANLOCA = LARGE LOCA * P:CNHEATREM = NO;
IF P:CNHEATREM = NO * C:PSFAIL = HOT LEG FAILURE;
THEN HIGH;
IF P:TRANLOCA=SBO*P:POWRECOV≠PRIOR RV FAIL*C:PSFAIL≠HOT LEG FAILURE;
IF P:TRANLOCA≠LARGE LOCA*P:CNHEATREM=NO*C:PSFAIL≠HOT LEG FAILURE;
THEN INTER;

RULE <RCSPRESS>

IF P:RCSPRESS = LO LO;
THEN LOW;
IF P:RCSPRESS = LO HI;
THEN MEDIUM;
IF P:RCSPRESS = HIGH;
IF P:RCSPRESS = HI HI;
THEN HIGH;

RULE <RECSPRAYS>

IF P:RECSPRAYS = NO;
THEN NO;
IF P:TRANLOCA=SBO*P:POWRECOV=PRIOR RV FAIL*P:RECSPRAYS=YES;
THEN YES;
IF P:TRANLOCA ≠ SBO * P:RECSPRAYS = YES;
THEN YES;
IF P:TRANLOCA = SBO * P:POWRECOV ≠ PRIOR RV FAIL;
THEN NO;

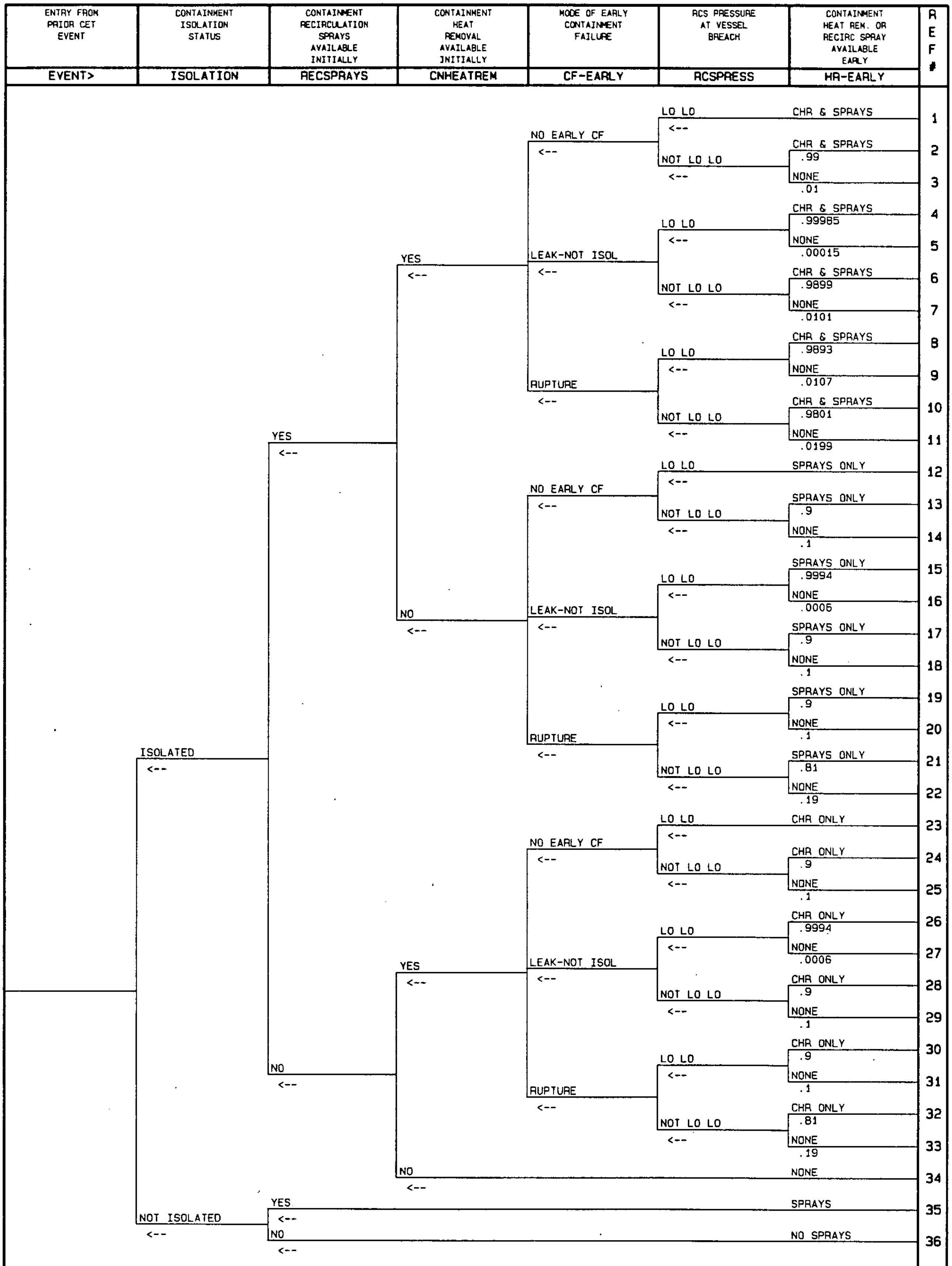


DIAGRAM: HR-EARLY.DET 22 MAR 92

Figure 4.6-4

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA
CONTAINMENT HEAT REMOVAL OR RECIRCULATION SPRAY AVAIL EARLY DECOMPOSITION EVENT TREE
REV. 0

FIGURE 4.6-4 (continued)

LOGIC RULES from <HR-EARLY.DET>

RULE <ISOLATION>

IF C:CF-EARLY = NOT ISOLATED;
THEN NOT ISOLATED;
IF C:CF-EARLY ≠ NOT ISOLATED;
THEN ISOLATED;

RULE <RECSPRAYS>

IF P:RECSPRAYS = NO;
THEN NO;
IF P:TRANLOCA=SBO*P:POWRECOV=PRIOR RV FAIL*P:RECSPRAYS=YES;
IF P:TRANLOCA=SBO*P:POWRECOV=PRIOR CONT FAIL*P:RECSPRAYS=YES;
THEN YES;
IF P:TRANLOCA ≠ SBO * P:RECSPRAYS = YES;
THEN YES;
IF P:TRANLOCA = SBO * P:POWRECOV = NEVER;
THEN NO;

RULE <CNHEATREM>

IF P:CNHEATREM = NO;
THEN NO;
IF P:TRANLOCA=SBO*P:POWRECOV=PRIOR RV FAIL*P:CNHEATREM=YES;
IF P:TRANLOCA=SBO*P:POWRECOV=PRIOR CONT FAIL*P:CNHEATREM=YES;
THEN YES;
IF P:TRANLOCA ≠ SBO * P:CNHEATREM = YES;
THEN YES;
IF P:TRANLOCA = SBO * P:POWRECOV = NEVER;
THEN NO;

RULE <CF-EARLY >

IF C:CF-EARLY = NO EARLY CF;
THEN NO EARLY CF;
IF C:CF-EARLY = LEAK;
THEN LEAK-NOT ISOL;
IF C:CF-EARLY = RUPTURE;
THEN RUPTURE;
IF C:CF-EARLY = NOT ISOLATED;
THEN LEAK-NOT ISOL;

FIGURE 4.6-4 (continued)

LOGIC RULES from <HR-EARLY.DET>

RULE <RCSPRESS >

IF P:RCSPRESS = LO LO;
THEN LO LO;
IF C:PSFAIL = HOT LEG FAILURE;
THEN LO LO;
IF P:PSPRESS ≠ LO LO * C:RCSFAIL ≠ HOT LEG FAILURE;
THEN NOT LO LO;

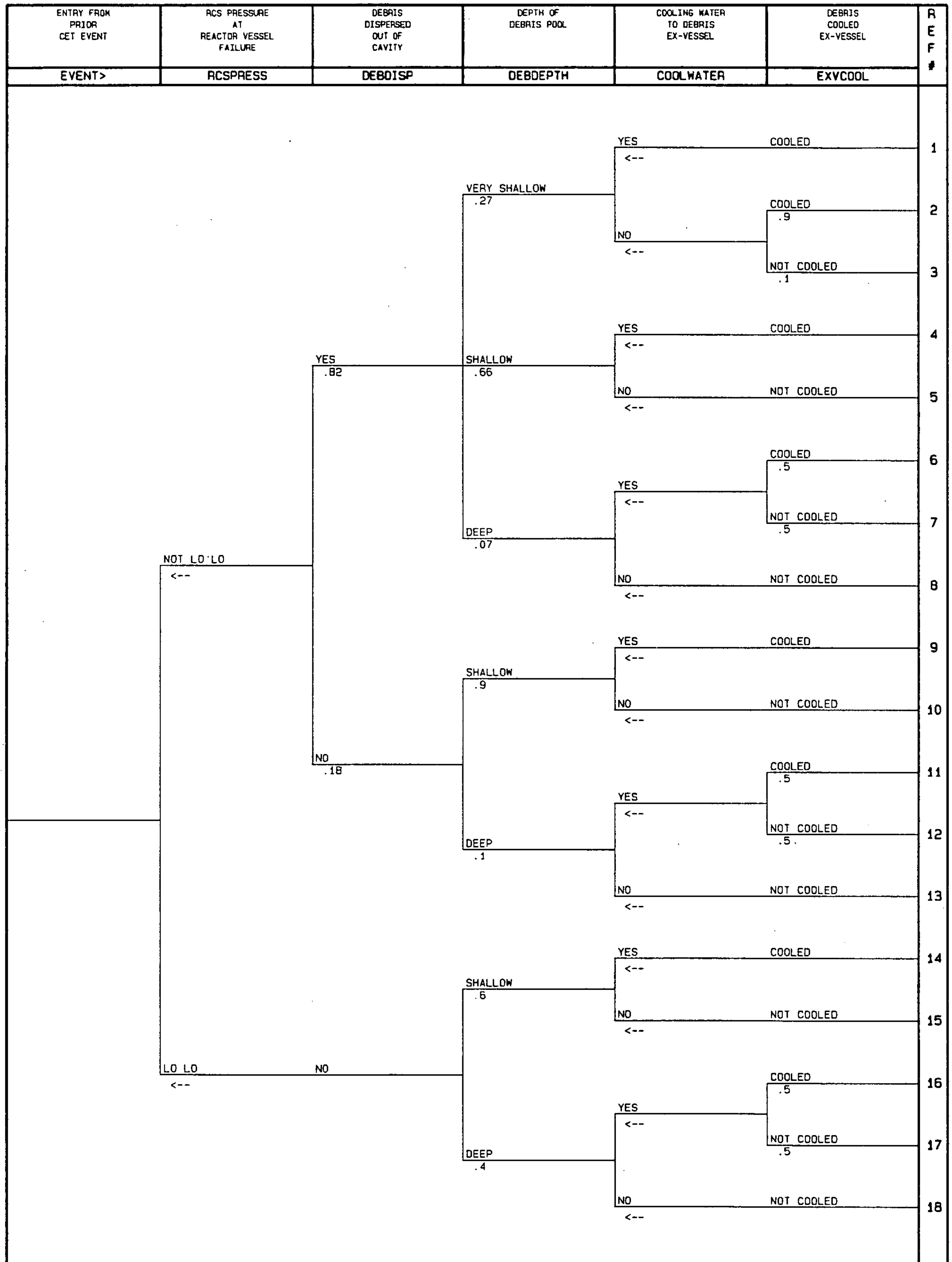


DIAGRAM: EXVCOOL.DET 23 MAR 92

Figure 4.6-5

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

DEBRIS COOLED EX-VESSEL
DECOMPOSITION EVENT TREE

REV 0

FIGURE 4.6-5 (continued)

LOGIC RULES from EXVCOOL .DET

RULE <RCSPRESS >

IF P:RCSPRESS = LO LO;
THEN LO LO;
IF C:PSFAIL = HOT LEG FAILURE;
THEN LO LO;
IF P:RCSPRESS ≠ LO LO * C:PSFAIL ≠ HOT LEG FAILURE;
THEN NOT LO LO;

RULE <COOLWATER>

IF C:HR-EARLY = CHR & SPRAYS;
IF C:HR-EARLY = CHR ONLY;
THEN YES;
IF C:HR-EARLY = NONE;
IF C:HR-EARLY = SPRAYS ONLY;
THEN NO;

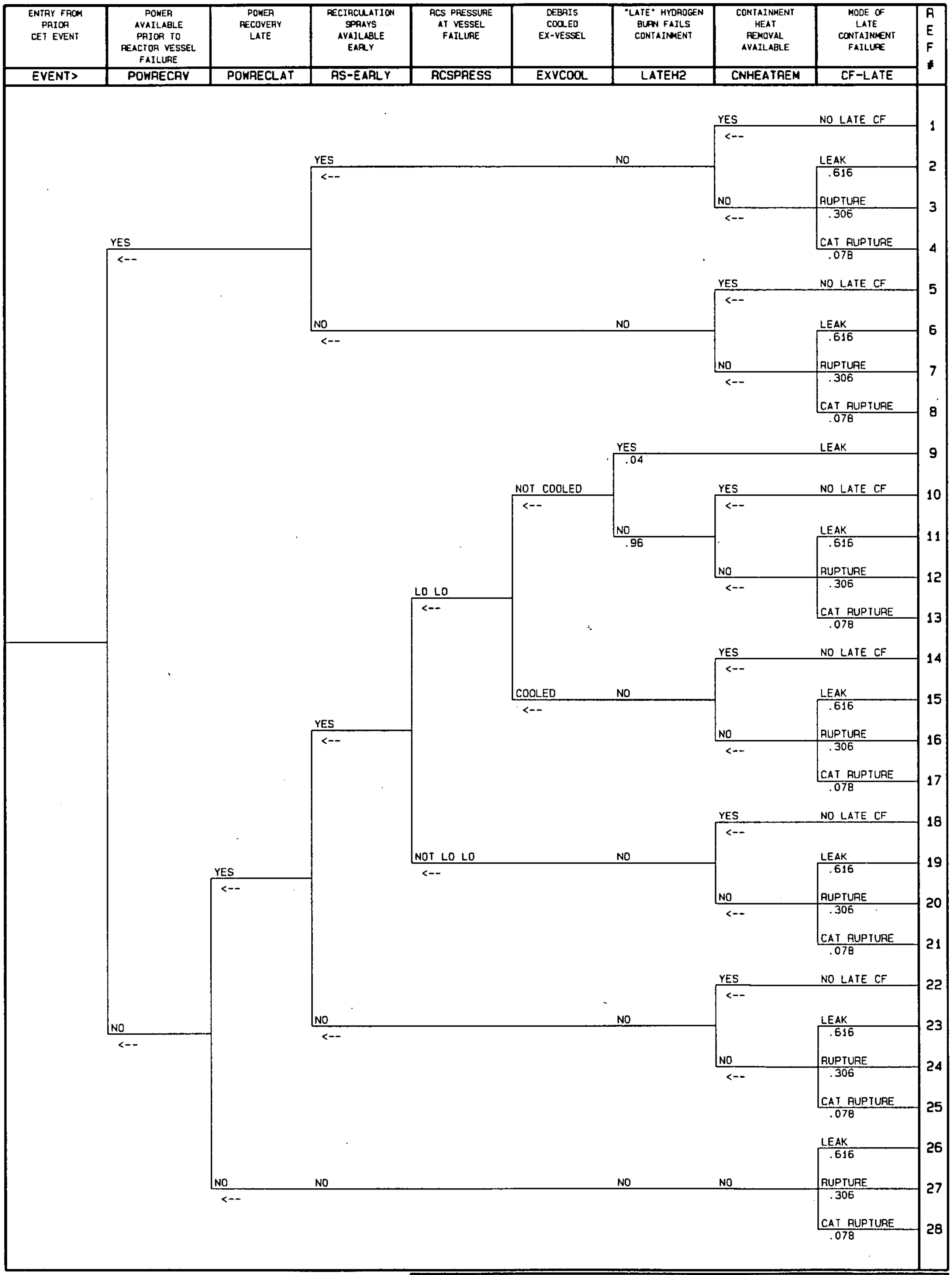


DIAGRAM: CF-LATE.DET 22 MAR 92

Figure 4.6-6

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

MODE OF LATE CONTAINMENT FAILURE
DECOMPOSITION EVENT TREE

REV. 0

FIGURE 4.6-6 (continued)

LOGIC RULES from CF-LATE .DET (page 1 of 2)

RULE <POWRECRV >

IF P:TRANLOCA ≠ SBO;
THEN YES;
IF P:TRANLOCA = SBO * P:POWRECOV = PRIOR RV FAILURE;
THEN YES;
IF P:TRANLOCA = SBO * P:POWRECOV ≠ PRIOR RV FAILURE;
THEN NO;

RULE <POWRECLAT>

IF P:POWRECOV = PRIOR CONT FAIL;
THEN YES;
IF P:POWRECOV ≠ PRIOR CONT FAIL;
THEN NO;

RULE <RS-EARLY >

IF P:RECSPRAYS = NO;
THEN NO;
IF C:HR-EARLY = NONE;
THEN NO;
IF C:HR-EARLY = SPRAYS;
IF C:HR-EARLY = CHR & SPRAYS;
THEN YES;

RULE <RCSPRESS >

IF P:RCSPRESS = LO LO;
THEN LO LO;
IF C:PSFAIL = HOT LEG FAILURE;
THEN LO LO;
IF P:RCSPRESS ≠ LO LO * C:PSFAIL ≠ HOT LEG FAILURE;
THEN NOT LO LO;

FIGURE 4.6-6 (Continued)

LOGIC RULES from CF-LATE .DET (page 2 of 2)

RULE <EXVCOOL >

IF C:EXVCOOL = COOLED;
THEN COOLED;
IF C:EXVCOOL = NOT COOLED;
THEN NOT COOLED;

RULE <CNHEATREM>

IF C:HR-EARLY = CHR ONLY;
IF C:HR-EARLY = CHR & SPRAYS;
THEN YES;
IF C:HR-EARLY = NONE;
IF C:HR-EARLY = SPRAYS ONLY;
THEN NO;

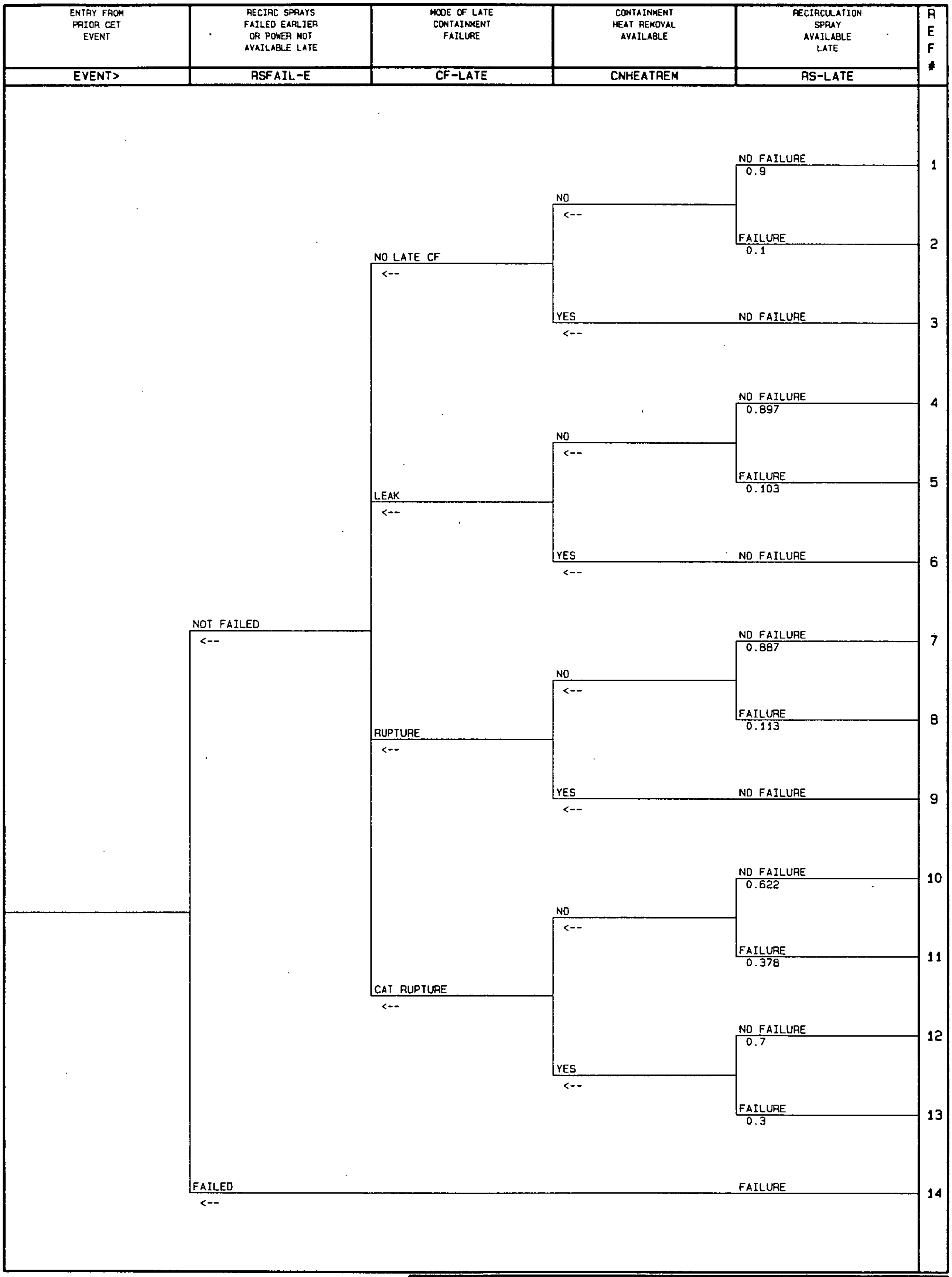


DIAGRAM: RS-LATE.DET 22 MAR 92

Figure 4.6-7

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

RECIRCULATION SPRAY AVAILABLE LATE
DECOMPOSITION EVENT TREE

REV. 0

FIGURE 4.6-7 (continued)

LOGIC RULES from RS-LATE .DET

RULE <RSFAIL-E >

IF P:RECSPRAYS = NO;
THEN FAILED;
IF C:HR-EARLY = SPRAYS ONLY;
IF C:HR-EARLY = CHR & SPRAYS;
THEN NOT FAILED;
IF P:POWRECOV = PRIOR CONT FAIL * P:RECSPRAYS = YES;
THEN NOT FAILED;
IF C:HR-EARLY = NONE;
IF C:HR-EARLY = CHR ONLY;
THEN FAILED;

RULE <CF-LATE >

IF C:CF-LATE = NO LATE CF;
THEN NO LATE CF;
IF C:CF-LATE = LEAK;
THEN LEAK;
IF C:CF-LATE = RUPTURE;
THEN RUPTURE;
IF C:CF-LATE = CAT RUPTURE;
THEN CAT RUPTURE;
IF C:CF-EARLY ≠ NO EARLY CF;
THEN NO LATE CF;

RULE <CNHEATREM>

IF C:HR-EARLY = NONE;
IF C:HR-EARLY = SPRAYS ONLY;
THEN NO;
IF C:HR-EARLY = CHR ONLY;
IF C:HR-EARLY = CHR & SPRAYS;
THEN YES;

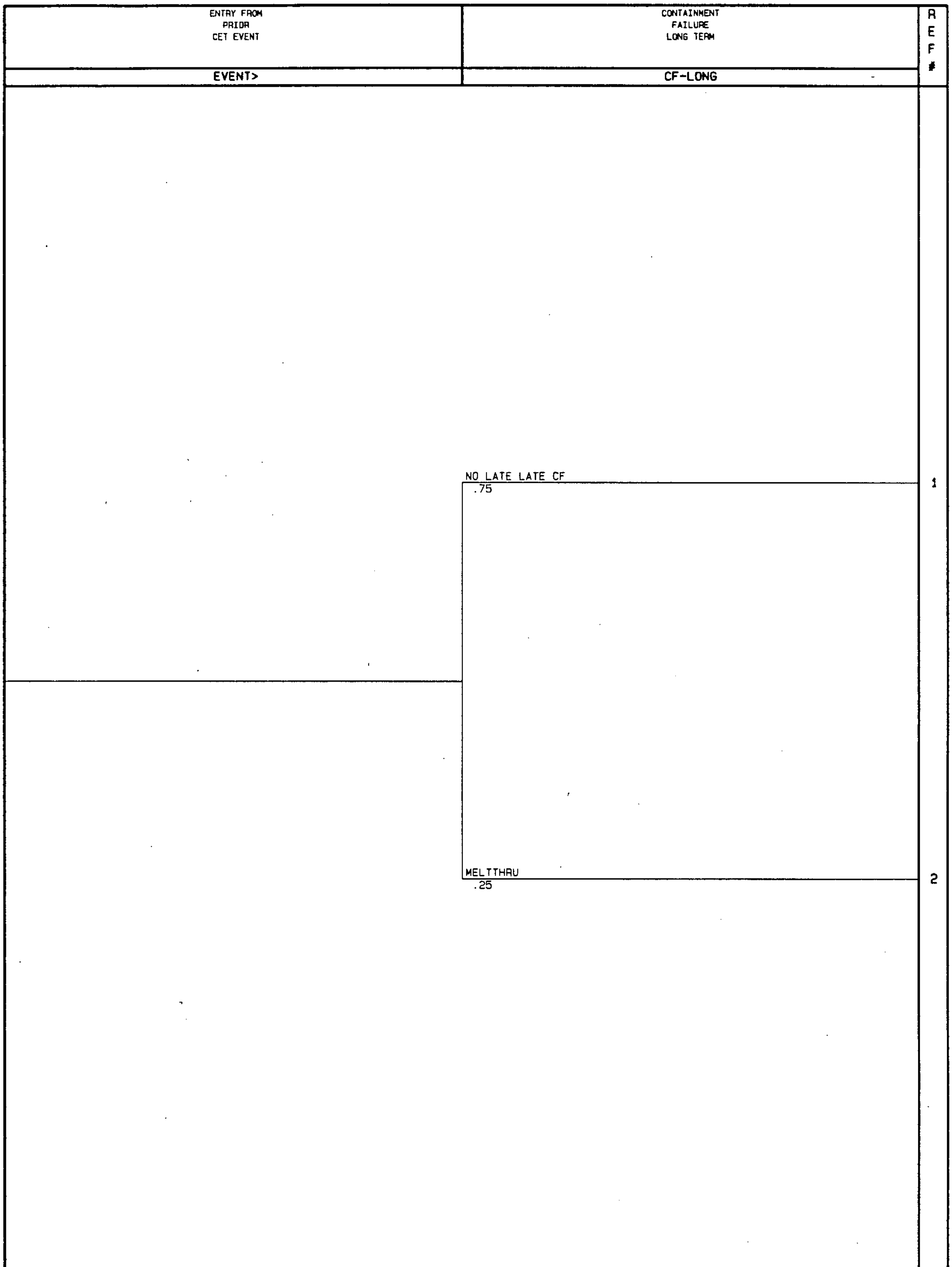


DIAGRAM: CF-LONG.DET 22 MAR 92

Figure 4.6-8

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA
CONTAINMENT FAILURE LONG TERM
DECOMPOSITION EVENT TREE
REV. 0

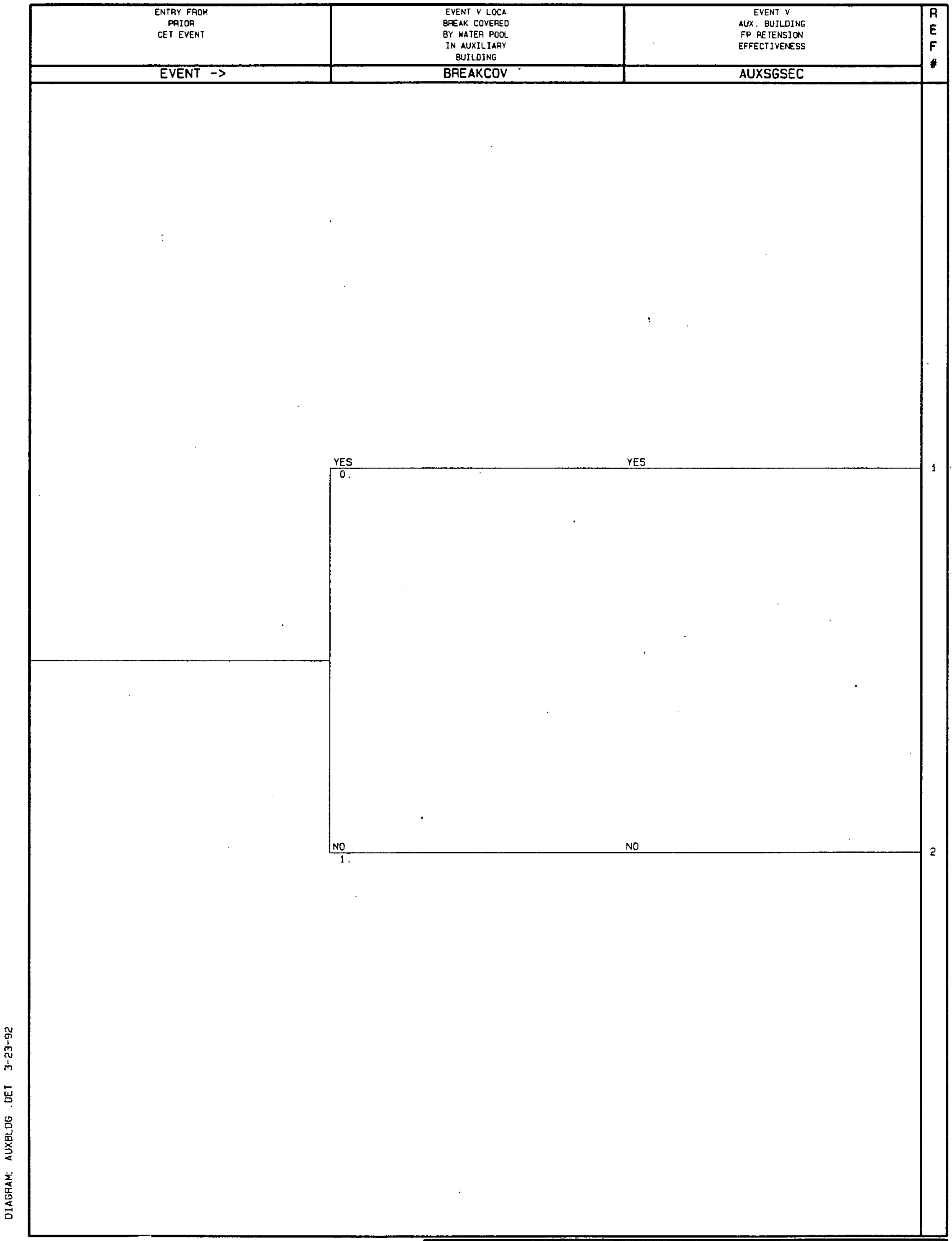


Figure 4.6-9

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA
EVENT V AUXILIARY BUILDING FP RETENTION EFFECTIVENESS
DECOMPOSITION EVENT TREE
REV. 0

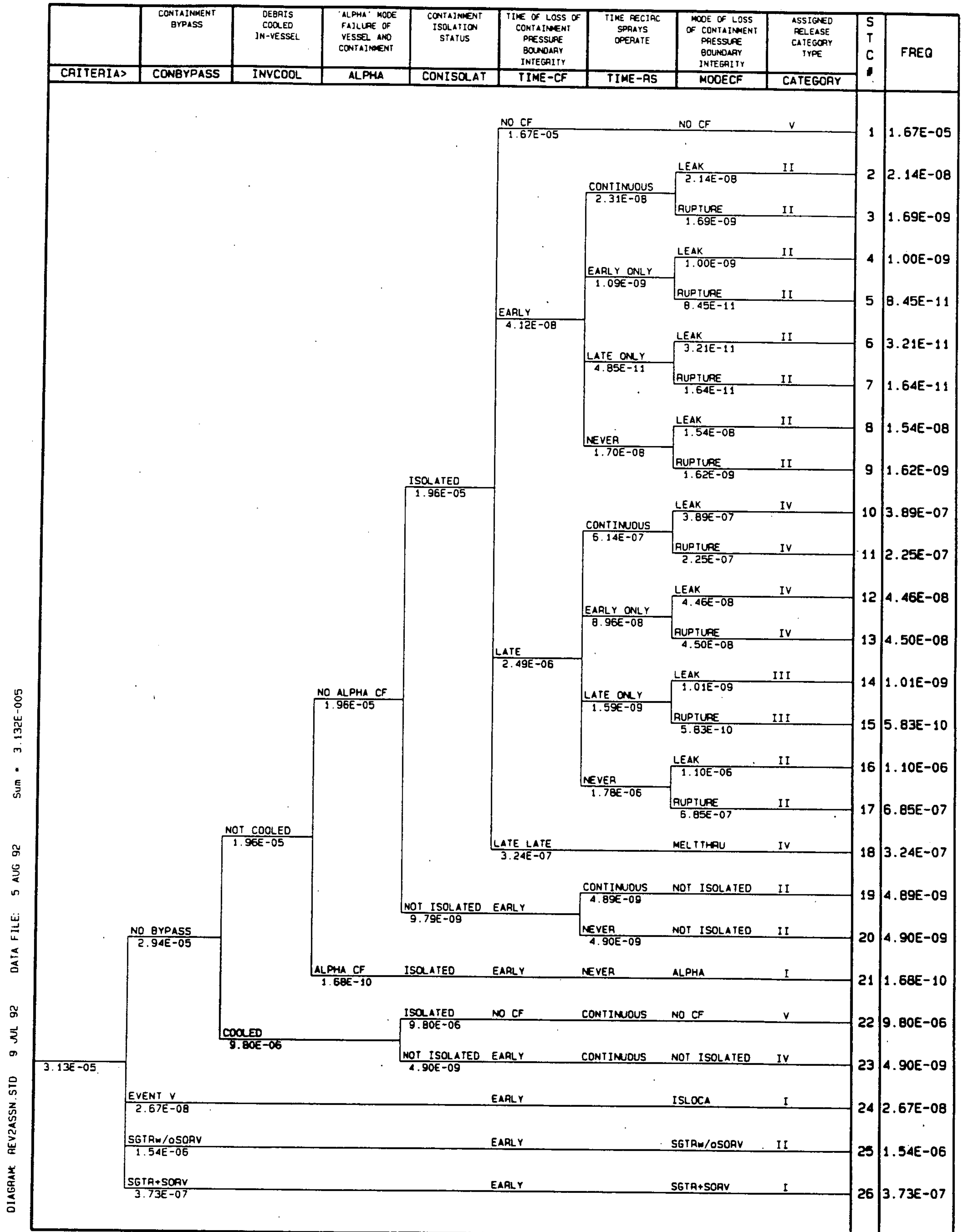


Figure 4.7-1

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

SOURCE TERM CATEGORY GROUPING DIAGRAM

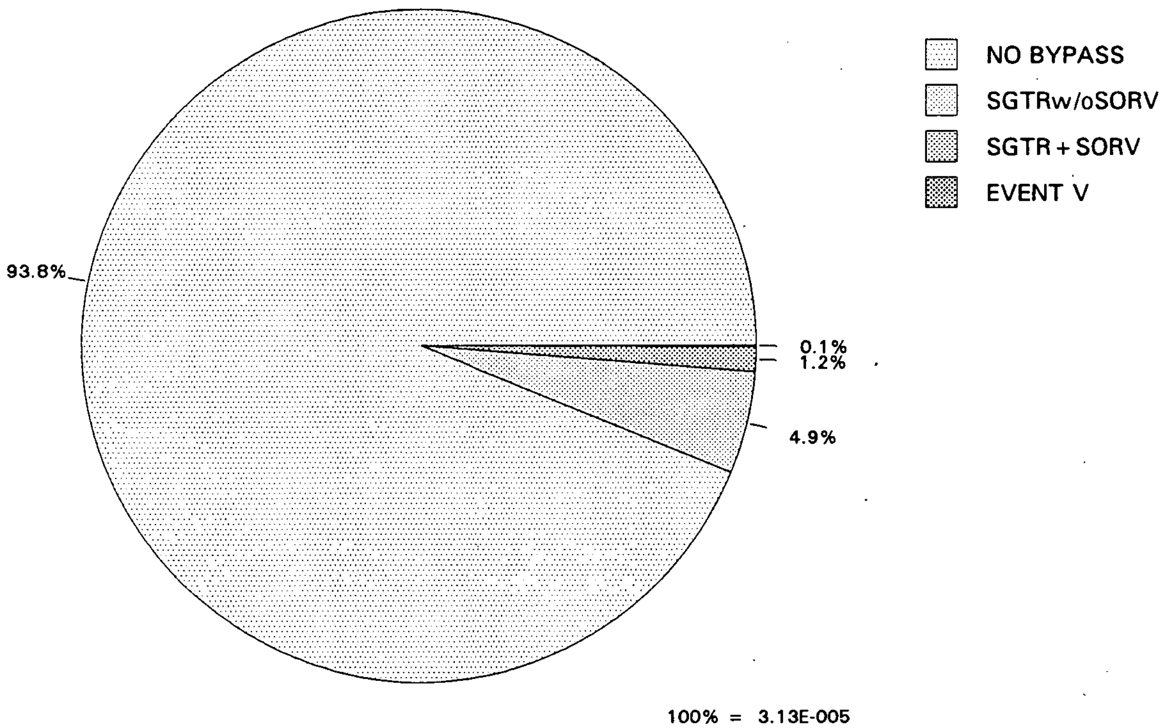


Figure 4.7-2
Bypass Sequence Proportion

Figure 4.7.2-3 Sequences Arrested In-Vessel.

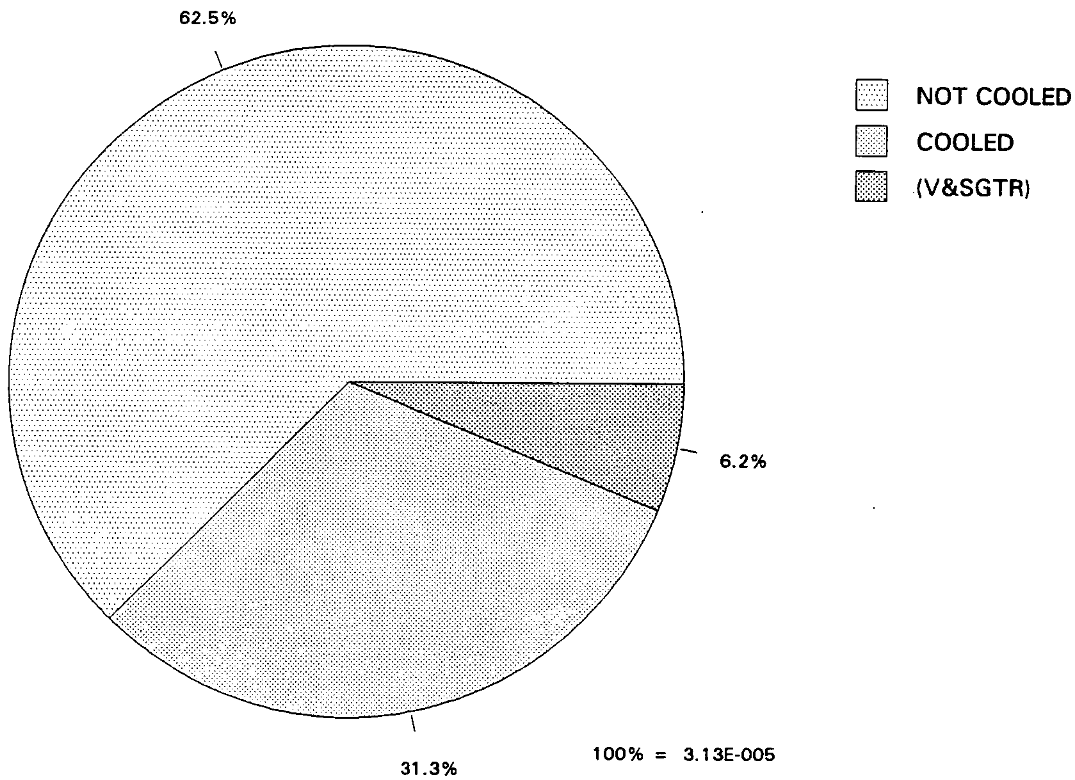


Figure 4.7-3
Sequences Arrested in Vessel

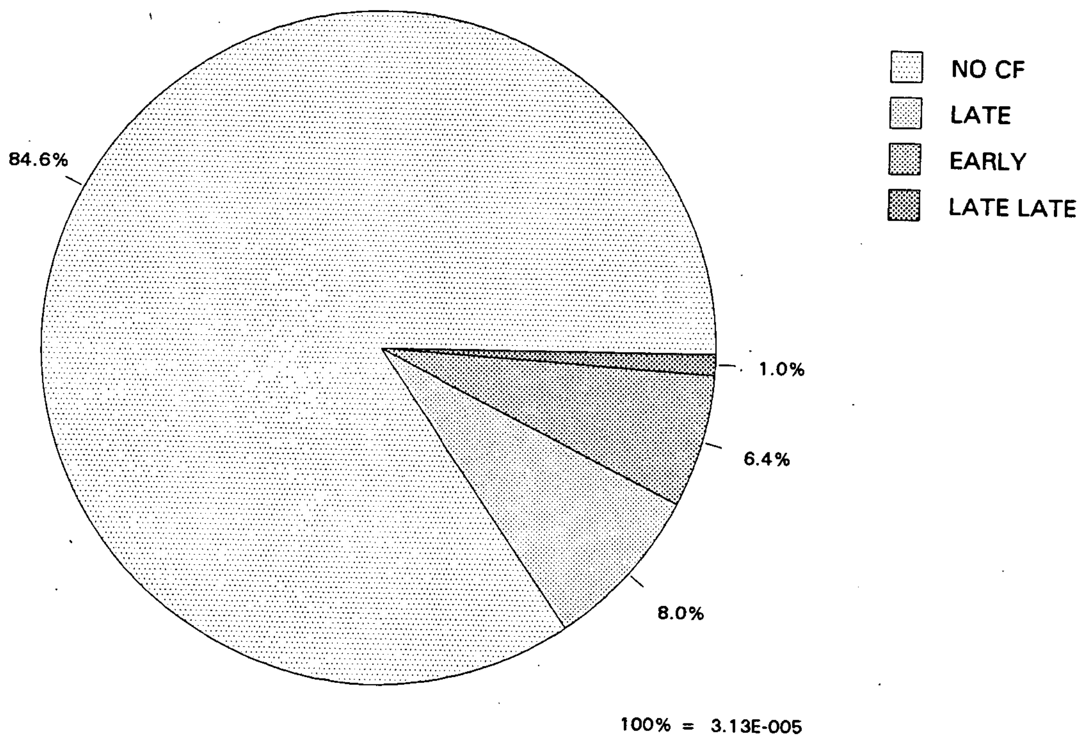


Figure 4.7-4
Time of Containment Failure

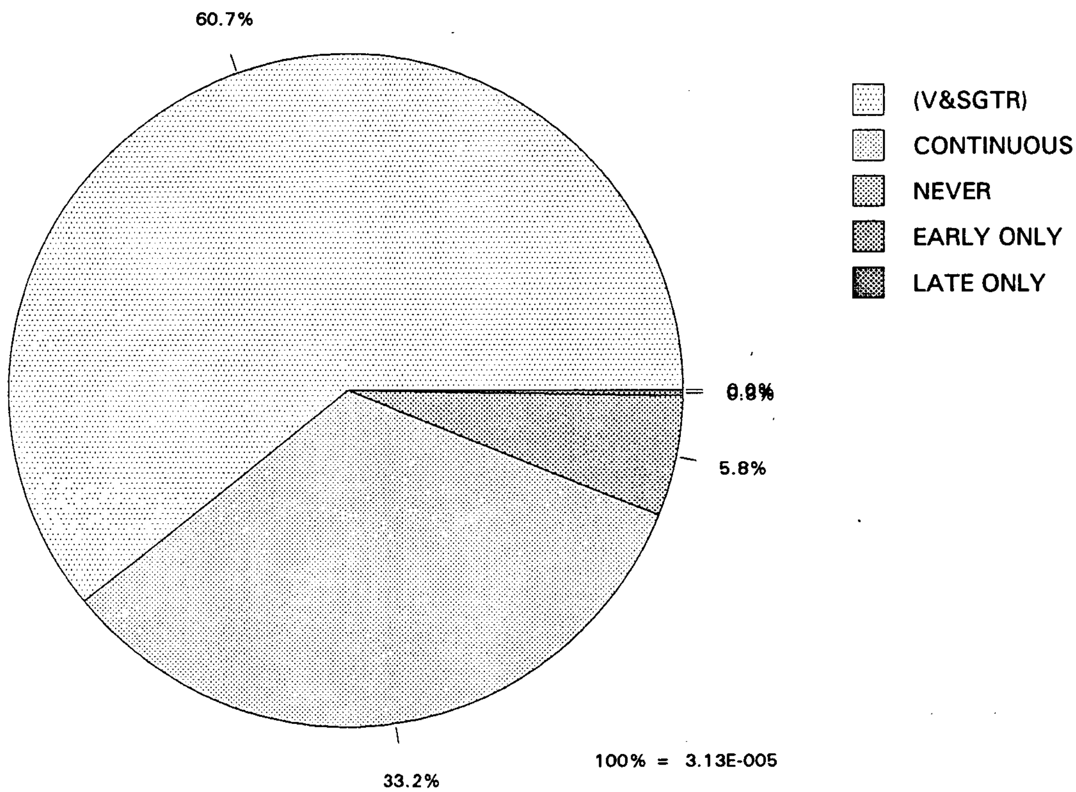


Figure 4.7-5
Spray Operation Time Interval

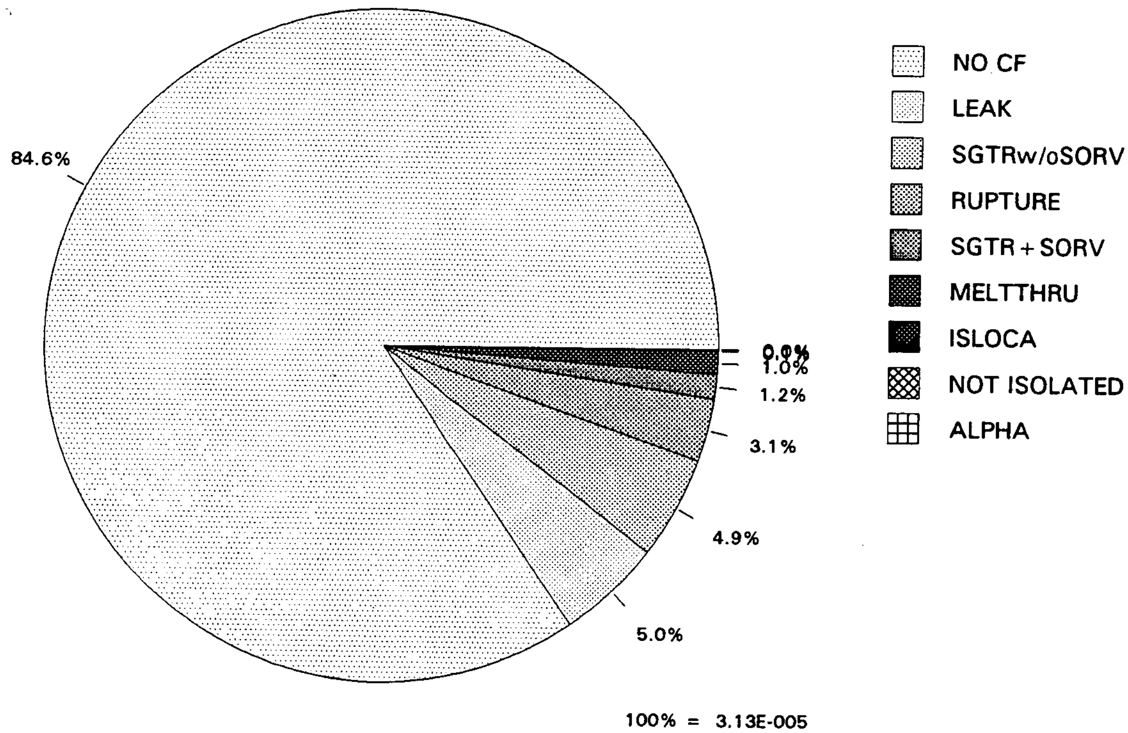


Figure 4.7-6
Mode of Containment Failure

Figure 4.7-7
Comparison of MAAP and NUREG 1150 Release
Fractions for Late Failure

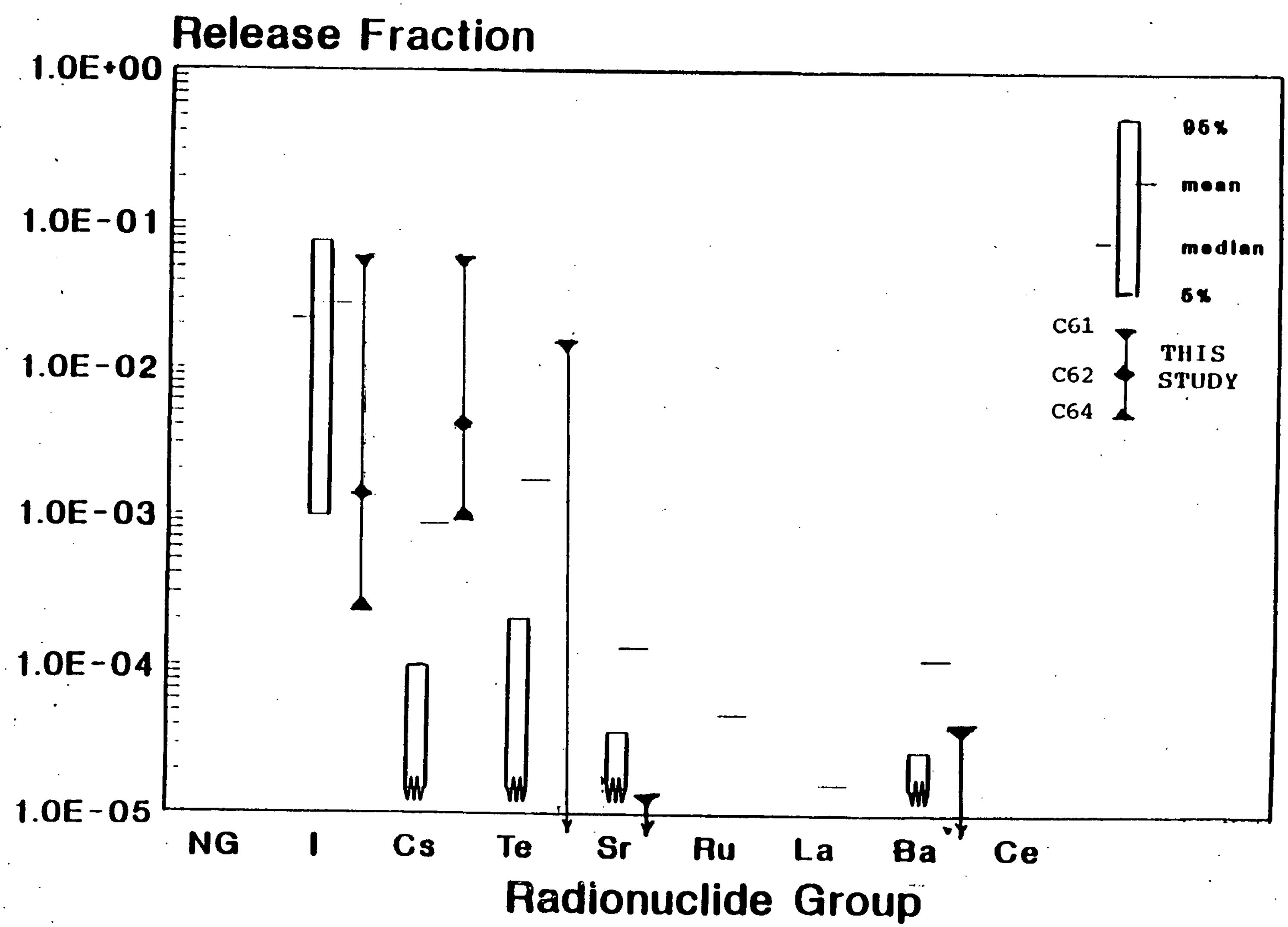
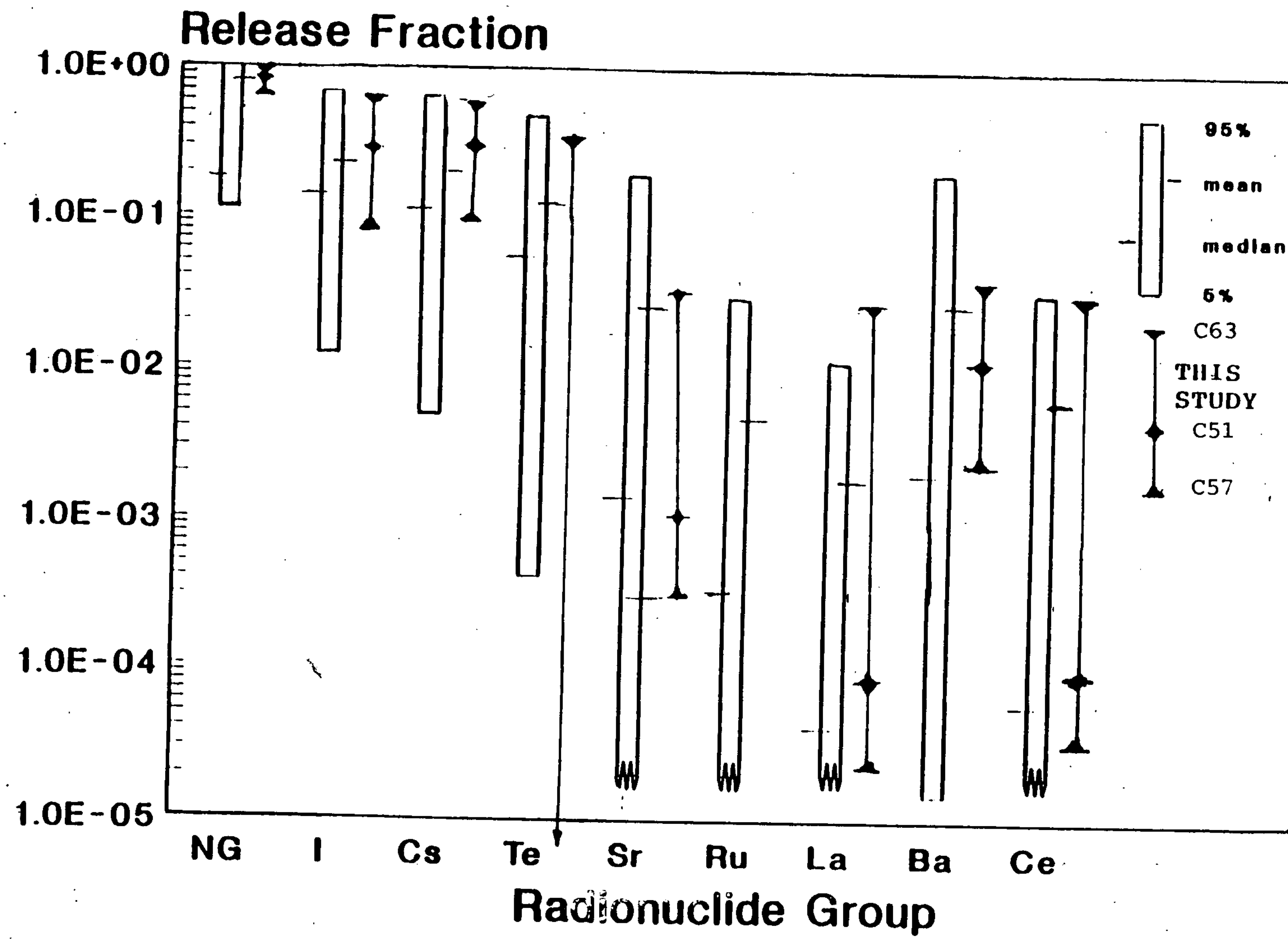


Figure 4.7-8
Comparison of MAAP and NUREG 1150 Release Fractions for Containment Bypass and SGTR Sequences



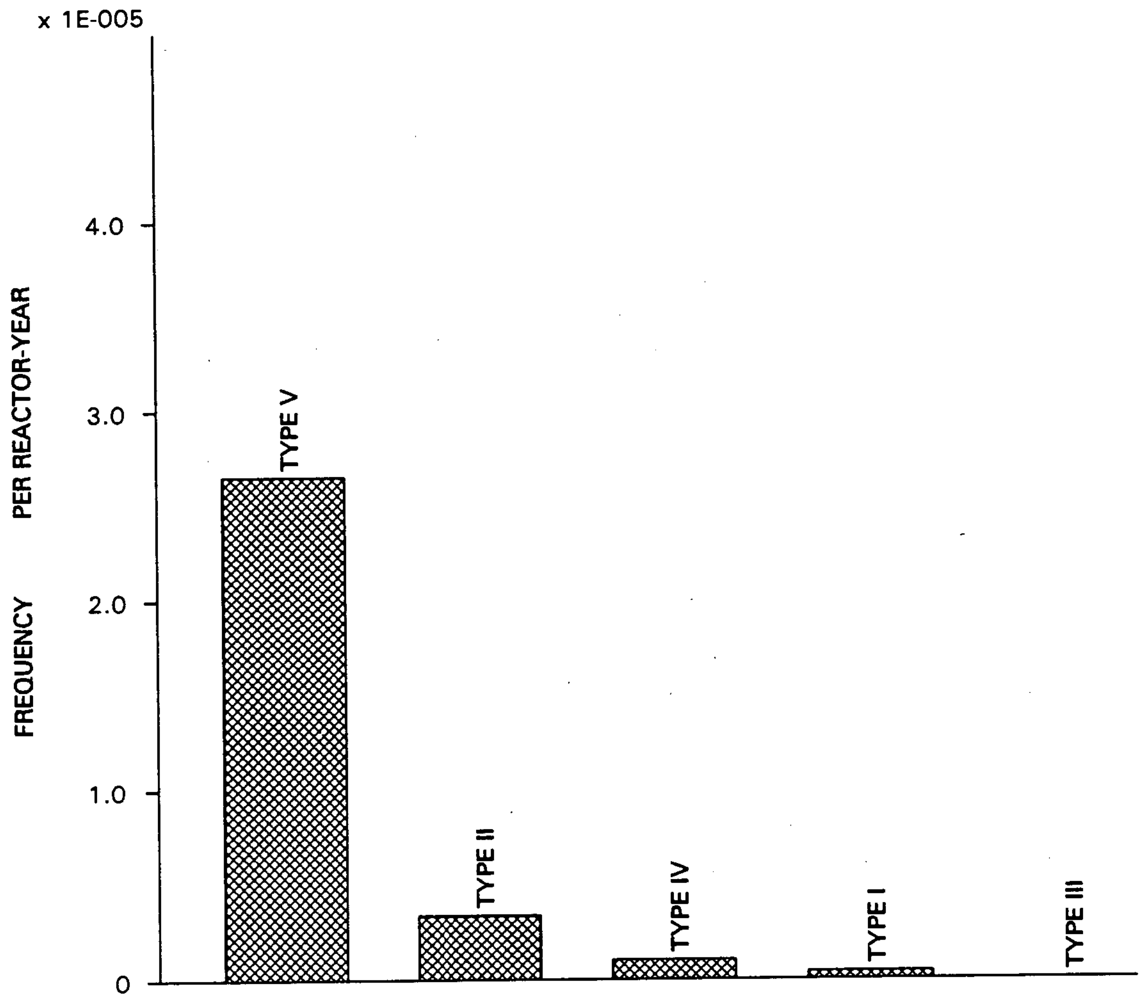


Figure 4.7-9
Release Type Occurrence Frequency

SECTIION 5.0

UTILITY PARTICIPATION AND INDEPENDENT REVIEW TEAM

5.0 UTILITY PARTICIPATION AND INDEPENDENT REVIEW TEAM

5.1 IPE Organization

The organizational structure for the Indian Point 2 IPE effort is provided in Figure 5.1-1. The prime objective was to foster a utility/consultant team effort while recognizing the need for unique expertise in some areas and the desire to continue application of existing risk insights into ongoing plant activities by utility team members. The organizational structure addresses the need for a coherent assignment of overall technical responsibility to the HNUS project manager while overall project responsibility remained with Con Edison.

Utility personnel were involved to varying degrees in all aspects of the IPE effort. The utility IPE team included two permanent members and several additional members who participated in specific tasks. The utility team members are part of the plant organization, are permanently located at the plant site and have direct, continuing access to plant facilities and equipment. As mentioned above, the Con Edison IPE team members are also involved in day-to-day application of PRA insights to plant activities. This is possible, based on the insights provided by the previously completed IPPSS and update efforts. The ability of Con Edison and HNUS to interface was enhanced by the fact that most of the work on the project was performed at, or near the plant site.

It should also be pointed out that the IPPSS effort, which was the foundation for the IPE, was also a joint effort, with substantial utility participation throughout the project. Although not members of the primary Con Edison IPE team, many of the Con Edison IPPSS participants are still part of the Con Edison organization, and were available, and utilized for consultation and review during the IPE effort.

The objective of utility participation in the IPE as discussed in NRC's guidance documents is to facilitate integration of the plant specific PRA insights into plant activities. We believe that our efforts to date in applying existing PRA insights and our participation in the IPE effort demonstrate a commitment to the NRC's objective.

5.2 IPE INDEPENDENT REVIEW

The IPE was subjected to a dual review process. All work was performed in accordance with approved quality assurance procedures which provided for formal review of all work products. This review was performed by both Con Edison and HNUS personnel and all comments were documented and resolved utilizing an established process. To further ensure the accuracy and validity of the work performed under the IPE, independent review was included in the project scope.

5.2.1 IPE Independent Review Team

The independent review performed for the IPE took full advantage of the Con Edison Independent Safety Review Section, located at the plant site, with additional assistance from other Con Edison personnel, which were not part of the IPE task team, where such additional review was deemed to be of value. The personnel who provided independent review for this study have expertise in operations, engineering, safety analysis and risk analysis. The Con Edison personnel who combined to provide the IPE independent review are shown in Table 5.2-1. In addition, the containment back-end analyses were independently reviewed by an outside consultant (Gabor & Kenton).

5.2.2 Review Comments and Resolution

The independent review performed for the IPE included:

- Project Plan
- Initiating Events
- Success Criteria
- Modelling Assumptions
- Screening Analyses
- Event Trees
- System Models
- Containment Event Trees
- Containment Strength Analysis
- Source Term
- Supporting Analyses
- Results

The independent review process was initiated at the beginning of the project and carried through to the final report. Comments were provided both on the basis of review of work products and presentation of analyses at review meetings. Comments from the independent review were documented and resolved utilizing the quality assurance process established for the project.

The comments provided as a result of the independent review were both general and detailed. Examples of comments which had the potential for impacting the IPE at the plant level are provided in Table 5.2.2.

TABLES FOR SECTION 5

TABLE 5.2-1

Con Edison Personnel Providing Independent IPE Review:

Reviewer	Area of Expertise
Manager, ISR*	Safety Analysis, Risk Analysis, Licensing
Licensed Senior Reactor Operator	Operations, Normal and Emergency Operating Procedures
Manager, Generation Support	Operations, Normal and Emergency Operating Procedures
Manager, Nuclear Analysis*	Nuclear and Transient Analysis, Licensing
Senior Engineer, Nuclear Safety*	Safety Assessment, Transient Analysis, Risk Analysis

* These reviewers were also members of the Con Edison team during performance of original Indian Point Probabilistic Safety Study.

TABLE 5.2-2

Examples of Independent IPE Review Comments and Resolution

Area of Review	Comment and Resolution
Recovery Actions	COMMENT: There is an inherent potential for recovering equipment through manual action built into the "response not obtained" actions in our symptom based EOP's. RESOLUTION: Although such actions were recognized in our evaluation, since the specific equipment recovery actions are not provided in the EOP's, operator actions associated with equipment recovery were not generally included in the model.
Operator Action	COMMENT: There is a high likelihood that the operators will progress through the EOP's following a small or medium LOCA such that they will initiate and achieve depressurization prior to switchover to recirculation. This is not currently credited in the model. RESOLUTION: Although the original IPPSS modelling was retained for this event, the potential for depressurization has now been included in the model for the small and medium LOCA events.
Event Tree Modelling	COMMENT: The plant model uses a single split fraction to represent Refueling Water Storage Tank failure for both the core injection and containment spray injection. These two functions are fed from separate taps off the RWST and only the core injection line has an isolation valve. RESOLUTION: This modelling choice does introduce a minor conservatism to the containment analysis portion of the model but was maintained based upon the interdependencies which exist between the core recirculation and containment spray recirculation functions. The current modelling allowed us to maintain a manageable event tree structure.

TABLE 5.2-2
(continued)
Examples of Independent IPE Review Comments and Resolution

Area of Review	Comment and Resolution
Event Tree Modelling	COMMENT: Given the typically assumed 24 hour mission time, does it make sense to specifically model hot leg recirculation which is not required for at least that period of time? RESOLUTION: Although the IPPSS did not incorporate the hot leg switchover models directly in the large and medium LOCA event trees and we understand that some more current analyses may show that hot leg recirculation may, in fact, not be necessary at all, we chose to retain this requirement for the large LOCA analysis in our current model. The risk impact of this function is minor. We may revisit this when a firmer technical basis is established.
Success Criteria	COMMENT: Is it clear from the references that one safety injection pump is sufficient to remove decay heat in the feed and bleed mode? RESOLUTION: Yes. Reference to the applicable Westinghouse analysis report has been included in the Success Criteria analysis file.
Operator Action	COMMENT: The plant model analysis file refers to use of alternate ("blue book") Emergency Operating Procedures. It was noted that the need for these procedures has been negated by changes made during the last refueling outage. RESOLUTION: The draft referred to was based on a review of both sets of procedures performed prior to the outage in order to bound the operator response in the model. The consolidated procedures resulting from the changes made during the past outage were again reviewed for additional impact. No significant impacts were found. The analysis file was revised to reflect the consolidated procedures.

TABLE 5.2-2
(continued)
Examples of Independent IPE Review Comments and Resolution

Area of Review	Comment and Resolution
Event Tree Modelling	COMMENT: The impact on causing a steam generator relief valve to stick open due to overfill of the steam generator should be included. RESOLUTION: The potential for steam generator overfill and the impact on steam generator relief valve failing to reclose was being addressed in the development of the Steam Generator Tube Rupture event tree.
Support System Depend-encies	COMMENT: The model assumes turbine trip on loss of all service water due to loss of cooling to auxiliaries. The turbine auxiliaries can now be fed by cooling from Unit #1 and would in those cases, continue to be available given no loss of offsite power. RESOLUTION: As pointed out, the turbine auxiliaries may be fed from either source. It should be noted, however, that the loss of non essential service water would result in loss of RCP motor cooling which would result in a reactor trip and subsequent turbine trip. The only potential impact would be if the turbine did not trip following the reactor trip which could result in an over-cooling transient. This is, however, a very low probability sequence and has no overall risk impact. Any impact on the turbine trip initiating event frequency would be covered by data updates.

TABLE 5.2-2
(continued)
Examples of Independent IPE Review Comments and Resolution

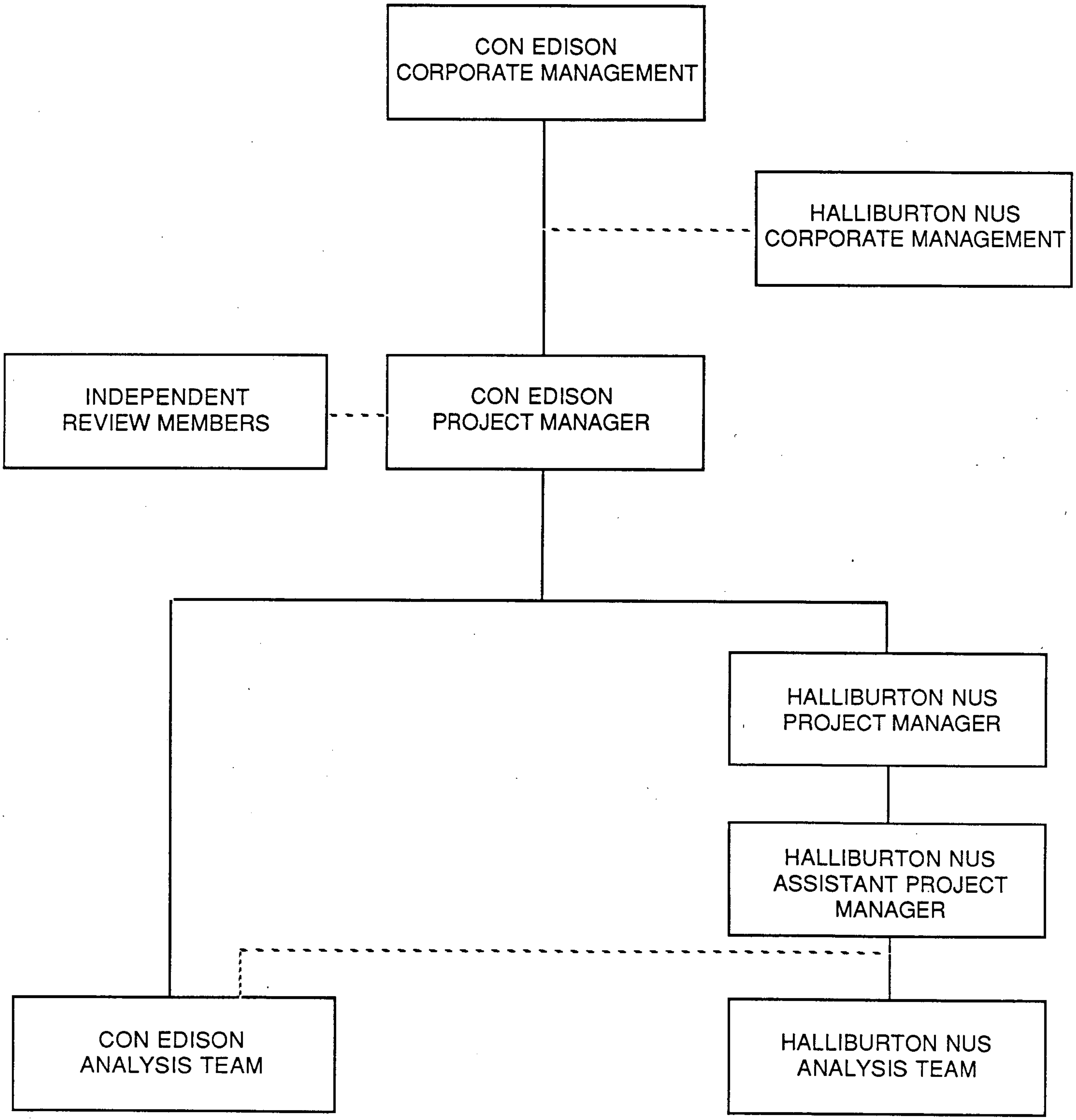
Area of Review	Comment and Resolution
Operator Action	COMMENT: The analysis of steam generator dryout time assumes operator action to initiate primary system feed and bleed at the time the steam generator level reaches the low level alarm point. The EOP's, however, provide for initiation at the 40% wide range level. This should be factored into the analysis. RESOLUTION: The feed and bleed analysis was revised to incorporate the provisions of the EOP.
Support System Depend-encies	COMMENT: The plant model should include consideration of the potential that the operator may utilize the post LOCA cooldown procedure in the EOP's to depressurize following a small LOCA with failure of high pressure injection. The current analysis assumes that depressurization can only occur by rapid secondary side steam dump and depressurization. RESOLUTION: This alternate depressurization method was subsequently included in the model
Success Criteria	COMMENT: The basis for determining the time to initiate steam generator cooldown and primary system cooldown following a steam generator tube rupture should be re-examined based on the AFW flow requirements associated with the plant power uprating and the guidance provided to the operator in OAD-26 to reduce feedwater flow. RESOLUTION: The systems analyses associated with the Steam Generator Tube Rupture event tree were modified to incorporate both of these factors.

TABLE 5.2-2
(continued)
Examples of Independent IPE Review Comments and Resolution

Area of Review	Comment and Resolution
Level 2 - Containment Strength	COMMENT: The analysis of containment strength in the IPPSS cites 141 psia as a lower bound number. This doesn't seem consistent with its use in the IPE as a median value. RESOLUTION: Although the approach taken may be slightly conservative, the inability to extract the basis for a failure distribution from the IPPSS analysis made the assignment of the pressure as a median value, appropriate. This potential conservatism was not expected to have a significant impact on the final results.
Level 2 - Containment Event Trees	COMMENT: The containment event trees do not appear to fully account for the fan cooler units in all appropriate sequences in the analysis of the containment heat removal function. RESOLUTION: The containment heat removal function treatment has been updated to reflect more consistent consideration of both the containment sprays and fan cooler units

FIGURES FOR SECTION 5

FIGURE 5.1-1
IPE PROJECT ORGANIZATION CHART



SECTION 6.0

PLANT IMPROVEMENTS AND UNIQUE SAFETY FEATURES

6.0 PLANT IMPROVEMENTS AND UNIQUE SAFETY FEATURES

6.1 Unique Safety Features

Specific safety features in the design of the Indian Point 2 plant help to minimize the frequency of events leading to core damage and fission product release and mitigate any associated source terms. Moreover, the design excludes specific vulnerabilities that have been identified at other plants.

6.1.1 Core Damage Related Safety Features

Plant Area Ventilation

The potential for, and the impact of, loss of ventilation cooling in the following critical plant areas has been examined and found not to be a significant risk contributor.

Central Control Room
Primary Auxiliary Building
Electrical Switchgear Room
Auxiliary Boiler Feed Pump Room
Cable Tunnel/Spreading Room
Turbine Building

The specific reasons for this vary from area to area but are generally as follows:

The prolonged period of time required after loss of ventilation before equipment integrity is challenged

The ability to detect loss of ventilation

The ability, using existing, proceduralized actions to establish natural or forced ventilation by opening doors or setting up portable blowers which allow direct ingress of fresh air from outside the building

The ability to shut down the plant safely using the alternate (Appendix R) safe shut down power supplies to selected safety related equipment. Although implemented primarily to cope with postulated fire damage to critical safety equipment in the switchgear room, cable tunnel or control room, this capability also enhances the ability to shutdown in the extremely unlikely event that ventilation is lost due to some non fire related event and normal or alternate ventilation is not re-established for a prolonged period.

The only area where loss of ventilation was found to be potentially significant was the Emergency Diesel Generator Building. This is addressed further in Section 6.2 and is specifically incorporated into the IPE model.

Auxiliary Feedwater Control Following Station Blackout

The design of the AFW turbine driven pump permits the operator to take local manual control even when DC control power is failed. Pneumatic steam generator and pressurizer instrumentation is also available which is independent of AC or DC power sources so that stable plant conditions can be maintained in the event of a prolonged station blackout even after battery capacity has been exhausted.

Under such circumstances, ventilation and cooling to the area housing the auxiliary feedwater equipment would be provided by opening the roll up door which gives direct access to the transformer yard.

Gas Turbines

Three gas turbines are available to supply power to the Unit 2 equipment in the event of a loss of offsite power and coincident emergency diesel generator failure. Gas Turbine Units 1 and 3 have full black start capability. Gas Turbine Unit 1 is located on the IP-2 site, Gas Turbines 2 and 3 are located close by at the Buchanan Substation.

Minimum operability requirements for the Gas Turbines are specifically addressed by plant technical specifications. Start up and connection of the Gas Turbines following an accident is directed in the Emergency Operating Procedures.

Backup Cooling of RHR, SI and Charging Pumps.

The normal source of cooling for the RHR, SIS and Charging Pumps is the Component Cooling Water System. However in the event of loss of component cooling, a hard-piped City Water cooling connection to the charging pumps is available and the associated Abnormal Operating Instruction (AOI) specifically directs the operators to align City Water backup cooling to the Charging Pumps. The same procedure also directs the operator to provide backup cooling to the SIS and RHR Pumps from either City Water or from a hard-piped Primary Makeup Water connection. Thus, the potential for RCP seal LOCA due to loss of all seal cooling and the inability to mitigate a LOCA associated with a loss of component cooling water (or Non-Essential Service Water which cools the CCW) is significantly reduced.

Recirculation Capability

Two sets of redundant low head pumps (RHR and Recirculation) are provided for recirculating water lost from the primary system to the Containment, through the RHR heat exchangers and back to the RCS and/or to the containment spray header rings. This arrangement serves: first, to provide additional hardware reliability, and second, to provide an enhanced potential for recovery should the operator fail to initiate timely switchover upon RWST depletion. No credit is taken for this latter benefit in the current analysis.

6.1.2 Containment Building Safety Features

Those plant features that are most important in inhibiting accident progession, preventing containment building failure and minimizing source term are:

High to Low Pressure Pipe Interface

Because the high to low pressure pipe interface on the RHR suction line from the RCS is located inside containment, rather than outside as is the case at many plants, there is a strong possibility that any loss of piping integrity would be inside containment in the unlikely event that the RHR suction valves were to fail. This design feature substantially reduces the frequency of interfacing LOCA events which could lead to containment bypass.

Containment Fan Coolers

The IP-2 Containment incorporates safety grade Containment Fan Coolers which provide a means, redundant to the Containment Spray System, of removing containment heat (thereby reducing pressure buildup) and removing radionuclides from the Containment atmosphere. This redundant system also allows removal of core decay heat in certain cases where flow through the core is established but the heat sink (i.e. the RHR heat exchangers or their associated support systems) is lost. The success criteria adopted for the fan coolers in this analysis is three out of five coolers which is conservative.

Recirculation System

As discussed above, the recirculation function at IP2, which can return water from the containment floor to the RCS or spray headers, is served by redundant systems. This further assures reliability of the recirculation system hardware.

Containment Isolation System

A special feature associated with the Indian Point 2 plant is the ability to provide additional sealing of those Containment locations which would be expected to pose the greatest potential for leakage should the pressure inside the Containment begin to rise. The systems which perform this function are the Isolation Valve Seal Water System (IVSWS) which provides pressurized water to the spaces between Containment Isolation valves and the Weld Channel and Containment Penetration Pressurization System (WCPPS) which provides pressurized air or nitrogen to the space within containment penetrations and to the channels covering the containment liner welds.

The High Capacity Large Containment

The IP2 design utilizes a large dry reinforced concrete containment which has a very high capacity for withstanding pressure increases, well beyond design basis. As a result of this high capacity, early containment failure is highly unlikely. Even if containment heat removal is not initially available, containment overpressure failure will not occur for an prolonged period (almost a day) allowing enhanced potential for recovery and additional source term reduction.

6.2 Plant Improvements

As discussed in Section 3.4, no vulnerabilities were found to exist at Indian Point Unit No. 2. Since an underlying objective of this effort is that these risk assessments be useful risk management tools to the individual utilities, areas of potential benefit were noted during the IPE. Two of these areas involve significant physical changes to the plant and do not provide sufficient risk reduction to be cost effective. Their potential for providing a positive risk benefit was recognized during the IPE, however, and was factored into the overall decision to implement a change:

<u>Gas Turbine Unit 2 Blackstart Capability</u> - The historical maintenance and performance data indicated that GT2 had the highest reliability of the three gas turbines associated with the Indian Point site. Unfortunately, GT2 had only limited ability to start and load under complete loss of AC power conditions. As a result of this limited capability, GT2 was not credited for power recovery in the IPE model. Although the risk impact of this was limited in our IPE due to a change in the power supply to CCW Pump 23 and the more sophisticated RCP seal LOCA model, upgrading GT2's blackstart capability provides the opportunity to include it more fully in determining the potential for power recovery and further offset any uncertainties in the seal LOCA model. Upgrade of GT2's blackstart capability is planned to be accomplished and will be linked to maintaining an upgraded reliability goal for the overall Gas Turbine equipment.

<u>Emergency Diesel Generator Building Ventilation</u> - The proper operation of the Emergency Diesel Generators depends on adequate ventilation heat removal in the building enclosing the EDG's. During the IPE it was recognized that due to power dependencies, loss of two of the EDG's could result in loss of all ventilation capability in the EDG Building and could fail the third EDG. This dependency is reflected in our IPE model. It was recommended that consideration be given to eliminating this dependency such that adequate ventilation be available to support any combination of operating EDG's. As a result of this risk reduction opportunity and additional considerations with regard to fan maintenance flexibility, an additional EDG Building fan is being installed which will be powered from the third EDG.

In addition, several administrative and procedural areas were found to contain opportunities for further consideration:

<u>Initiation of Primary Bleed</u> - In the event of a loss of secondary side cooling following a transient, the existing Emergency Operating Procedures (EOPs) direct the operator to initiate primary system bleed and feed operation using the pressurizer PORV's upon reaching a predetermined steam generator level. Although the procedures directing bleed and feed are clear and the operators are well trained in those procedures, the time available is somewhat limited. The potential for the operator to be successful in accomplishing bleed and feed cooling could be enhanced by extending the time available. This could be accomplished by stipulating an earlier point in the EOPs for initiating the

bleed operation. Such a change could have generic implications, however, and may introduce unforeseen negative impacts. We will be further investigating the desirability of an EOP change in this area.

PORV Block Valve Position - Until recently, Indian Point Unit No.2 generally operated with block valves, which are in series with the pressurizer PORV's, in the closed position. This introduces an additional demand challenge when bleed and feed is called for. Although the operating philosophy has changed such that the block valves remain open except in the event of PORV leakage, insufficient operating history was available to incorporate this change into the IPE model. We intend to monitor changes in the operating position of these valves to try to develop a fuller basis for incorporation into the model. Operating personnel have been apprised of the enhanced risk importance of these components in order to facilitate appropriate consideration when deciding to close a block valve.

EDG Building Ventilation Fan Testing - The EDG Building fan units are not normally running unless the EDG building air temperature is greater than their associated set point. Although the monthly diesel generator test procedure requires verification that sufficient fans are operating to maintain the building temperature below 100°F, this test may, but does not necessarily, verify operation of more than one fan. There has been no other specific periodic test of the fans during plant operation. To provide a fuller technical basis for assessing the reliability of those fans, it was recommended that periodic testing of all the EDG Building fans be established. Such a test is being implemented.

In addition to the above, changes in the relative risk importance of the various plant systems and activities determined in the IPE will be factored into the existing IP2 risk based prioritization systems and will continue to be included in the overall decision making process.

TABLES FOR SECTION 7

TABLE 7.2-1
Comparison of Core Damage Frequency by Initiator Group

Initiating Event Group	IP2 IPE	IPPSS (1982)	NUREG[1] 4550 Zion	Surry[2] IPE	Turkey[3] Point
LOCAs	1.04E-05 (33.30%)	4.4E-05	6.7E-06	2.1E-05	2.7E-05
Steam Generator Tube Rupture	1.62E-06 (5.98%)	1.3E-06	1.5E-06	1.0E-05	4.1E-06
General Transients	1.43E-05 (41.40%)	3.6E-06	3.0E-04	3.2E-05	4.4E-07
Station Blackout	4.47E-06 (14.26%)	2.96E-05	6.7E-06	8.1E-06	5.6E-05
Interfacing Systems LOCA	2.67E-08 (.09%)	3.5E-07	1.1E-07	1.6E-06	4.3E-07
Anticipated Trans-ients w/o Scram	1.81E-06 (5.78%)	1.21E-06*	7.1E-06	3.2E-07	3.2E-06
Total CDF	3.13E-05	7.9E-05	3.4E-04	7.5E-05	1.0E-04

1 NUREG 4550, Zion (Ref. 7.2-3)
2 Surry IPE (Ref. 7.2-4)
3 Turkey Point IPE (Ref. 7.2-5)
* The IPPSS ATWS value includes only the dominant sequences reported in IPPSS Table 8.3-9A-1.

TABLE 7.3-1
Comparison of Containment Failure Mode Frequencies

Containment Failure Mode	IP2 IPE	IPPSS[1]	NUREG 1150[2] (Zion)
No Containment Failure	2.65E-05	7.6E-05	2.4E-04
Late Containment Failure	2.49E-06	1.8E-06	7.8E-05
Type II	(1.79E-06)		
Type IV	(6.90E-07)		
SGTR w/oSOV Type II	1.54E-06***	*	**
Late Late Containment Failure (Type IV)	3.25E-07	**	1.5E-06
Bypass (Type I)	3.99E-07	3.5E-07	1.5E-06
SGTR w/SOV	(3.73E-07)	*	(1.4E-06)
Interfacing LOCA	(2.68E-08)	(3.5E-07)	(1.1E-07)
Early Containment Failure (Type II)	4.12E-08	2.6E-09	5.0E-06
Steam Explosion (Type I)	1.68E-10	**	**
Isolation Failure (Type II/IV)	1.47E-08	**	**
	3.13E-05	7.9E-05	3.3E-04

1 IPPSS Table 8.3-2A-1
2 NUREG 1150 Zion (Ref. 7.2-6)
* The total SGTR core damage frequency as reported in the IPPSS (Table 8.3-2A-1) was 1.3E-06. Section 1.4.2 provides additional information.
** Not reported
*** Includes contribution from SGTR initiating events and induced SGTRs

FIGURES FOR SECTION 7

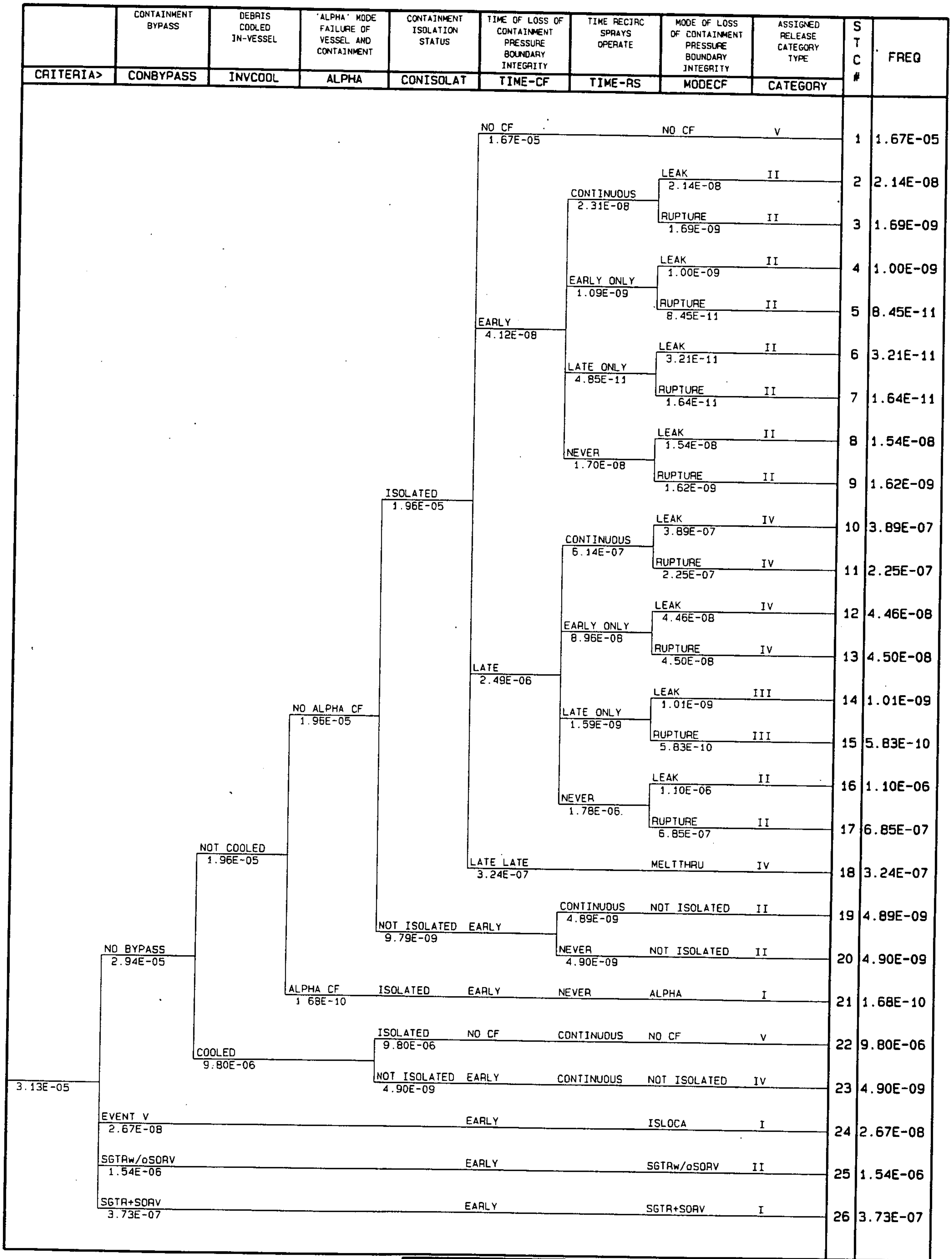


DIAGRAM: REV2ASSN.STD 9 JUL 92 DATA FILE: 5 AUG 92 Sum = 3.132E-005

Figure 7.3-1

CONSOLIDATED EDISON COMPANY
INDIAN POINT 2 INDIVIDUAL PLANT EXAMINATION PRA

SOURCE TERM CATEGORY GROUPING DIAGRAM

SECTION 7.0

SUMARY AND CONCLUSIONS

7.0 SUMMARY AND CONCLUSIONS

7.1 Introduction

The IP-2 IPE study represents a comprehensive revision of the internal events portion of the original Indian Point Probabilistic Safety Study (IPPSS), which was a landmark document published in 1982. Hardware and procedural changes have been identified and incorporated into the model, and component performance histories since the completion of the IPPSS have been evaluated in order to develop an updated component performance data base. Success criteria has been re-evaluated and where appropriate, new success paths have been incorporated into the event trees, some of which are substantially different from the original IPPSS study. Recent advances in Level 1 PRA methodology have been applied, primarily in the areas of Human Reliability Analysis and Common Cause Failure Analysis. The containment performance analysis and the treatment of source terms have been revised to better address the issues of concern defined in the Generic Letter. As part of the Level 2 portion of the IPE, a plant specific MAAP model has been utilized and updated and expanded containment event trees have been developed and quantified.

In this section, the findings of the IP-2 IPE study are summarized and compared with the results from earlier IP-2 studies and other recent PRA studies for Westinghouse PWR's. The Core Damage frequency (Level 1) results are discussed in section 7.2 and the containment performance results are discussed in section 7.3. Sections 7.4 and 7.5 address the study's conclusions regarding "vulnerabilities" and the resolution of GSIs/USIs, respectively.

7.2 Core Damage Frequency Results

The mean core damage frequency for Indian Point 2 from all internal initiating events is determined to be 3.13E-05 per year. The highest contribution comes from transient accident sequences involving loss of both primary and secondary heat removal in the injection phase. The next highest contribution comes from LOCAs with failure of core cooling injection in the Recirculation phase. Other lesser contributions come from induced LOCAs following loss of offsite power, LOCAs with failure during the injection phase, ATWS and Steam Generator Tube Rupture sequences.

The contributions, by initiator, to the IP-2 core damage frequency derived in this IPE are compared with the original IPPSS results and the results of other studies in Table 7.2-1.

Despite the inclusion of a much more comprehensive common cause failure model in the IP2 IPE (which would, by itself, tend to drive the CDF upward), the overall estimate of core damage frequency when compared with the original IPPSS results has decreased. The principal reasons for this are:

(i) the adoption of a much more realistic, time dependent RCP seal LOCA model which gives more credit for AC power recovery and significantly reduces the contribution from station blackout scenarios, and

(ii) the incorporation of more realistic system success criteria which reflects the EOP direction given to the operators to depressurize the RCS and inject with low pressure pumps following small and medium LOCAs with failure of high pressure pumps.

The estimate of the Interfacing LOCA frequency has also been reduced through a new analysis which mirrors that performed by Brookhaven for IP3 (NUREG/CR 5102, Ref. 7.2-1), and accounts for the strong possibility of line rupture inside rather than outside containment due to the loction of the high/low pressure pipe interface.

The contribution from general transients with successful scram has increased. The reason for this is a more realistic evaluation of operator error associated with the initiation of primary bleed failure following failure of secondary cooling. This analysis accounts for the plant specific characteristics which affect the time available for the operator to initiate primary bleed. The Auxiliary Feedwater unavailability estimate has also increased due to the addition of potential common cause failures of the motor driven pumps.

The increase in contribution of the ATWS event reflects the use of a completely revised ATWS event tree model based on the work performed for the Westinghouse Owners Group (Ref. 7.2-2).

In comparing the IP2 IPE results with other studies, the contributors are generally similar with one major exception, namely the Zion transient sequences. However on closer inspection, the major contributors to that group (86% of the total CDF) comes from RCP seal LOCAs induced by loss of Component Cooling or Service Water as an initiating event. Although such sequences are included in the IP2 IPE, their frequency is considerably lower due to the arrangement at IP2 which allows cooling of the charging pumps, and the SIS and RHR pumps with city water (as well as primary makeup water which is not credited). This capability did not exist at Zion at the time the reference PRA was performed.

7.3 Release Category Frequencies and Dominant Sequences

As in the original IPPSS, the IPE results show that the Indian Point 2 Containment Building is capable of withstanding almost all core damage scenarios and is very likely to remain intact following a core damage event.

Twenty six source term release categories were developed for use in grouping the containment sequences. For convenience and clarity, the various source term classes in this work are classified into the following general release category types:

TYPE I:	I,Cs release fractions >= 0.2
TYPE II:	I,Cs release fractions >= 0.04
TYPE III:	I,Cs release fractions >= 0.002
TYPE IV:	I,Cs release fractions < 0.002
TYPE V:	No containment failure - normal leakage

The above release type ranges were fixed according to the IPE reporting requirements as well as natural breakpoints in the magnitude of the various source terms generated by the analysis.

Types I and II both exceed the magnitude of the WASH 1400 PWR-4 release category and thus according to the Generic Letter definition are recognized as significant release. The release type frequencies per year are shown in Figure 7.3-1 and are listed below.

TYPE I:	3.99E-07
TYPE II:	3.38E-06
TYPE III:	1.59E-09
TYPE IV:	1.03E-06
TYPE V:	2.65E-05

A comparison of the release types and frequencies from this study is made with the IPSSS Study and NUREG 1150 for Zion (see Table 7.3-1). Overall, the estimated frequency of a significant (Type I or Type II) release at IP2 following core damage is approximately the same in this study as was found in the IPPSS.

Core melt scenarios following a steam generator tube rupture in which isolation is not achieved (e.g. a safety valve failed to reclose) were determined to be a Type I release with a calculated frequency of 3.73E-7 per year. Core melt scenarios following a steam generator tube rupture in which steam generator isolation is achieved (ie. a safety valve successfully reclosed following reduction of pressure below its setpoint) were determined to be a Type II release with a frequency of 1.25E-6 per year. The IPPSS calculated an overall core melt frequency following a SGTR initiating event of 1.3E-6 per year and assigned it a source term range which spanned both the Type I and II release categories (IPPSS Section 1.3.4.4.3). The results for the steam generator tube rupture accidents arising from this IPE study are, therefore, similar to the IPPSS result.

The IPE evaluated a third type of steam generator tube rupture scenario due to transient scenarios in which core damage occurs with the primary system at high enough temperature and pressure introduce the possibility of an induced steam generator tube rupture. This has a calculated frequency of 2.5E-7 per year and was determined to be a Type II release. The IPPSS predated consideration of this phenomenon and while there is no comparable value in the IPPSS, it would not be expected to be significantly different.

The only other contributor to Type I releases is the Interfacing Systems LOCA with a frequency of 2.68E-8 per year which is significantly lower than the IPPSS value of 3.4E-7 per year due to the additional work done by Brookhaven National Laboratory, under contract to the NRC, on this issue with specific application to the Indian Point design.

Other significant contributors to the Type II releases category are due to late containment overpressurization following, for example, small and medium LOCA with loss of all ECCS and failure of containment heat removal due to system related failures or adverse environmental conditions within containment. The frequency of late containment overpressurization releases was approximately 1.8E-6 per year in the IPPSS versus a frequency of 1.79E-6 per year for Type II late containment overpressurization releases in the IPE.

7.4 Vulnerabilities

No core damage or containment vulnerabilties were identified as a result of performing the IPE. This is demonstrated in Section 3.4 by application of the NUMARC Severe Accident Closure Guidelines (NUMARC 91-04, Ref. 7.2-7), the performance of various sensitivity and importance reviews and comparison of the results with proposed safety goals.

Although no specific vulnerabilities were found, many insights were gained as the importance of specific components and proceduralized operator actions. As was done using past PRA insights, insights from the IPE will also be factored into the plant decision making process.

7.5 Resolution of USI/GSIs

This report addresses one unresolved safety issues with respect to internal initiating events:

> "USI-A45, Decay Heat Removal" which is addressed in the previous section. The conclusion from that evaluation is that there are no vulnerabilities in this area.

No other issues have been identified at this time that are resolved via this IPE report. However it is expected that the risk analysis for IP-2 may be used in the future to directly resolve or assist in resolving generic issues.

7.6 References for Section 7

7.2-1. NUREG\CR-5102 Interfacing Systems LOCA: Pressurized Water Reactors", February 1989.

7.2-2. WCAP 11993 " Assessment of Compliance with ATWS Rule Basis for Westinghouse PWRs", December 1988.

7.2-3. NUREG/CR-4550 Vol &, Rev 1 "Analysis of Core Damage Frequency: Zion Unit 1 Internal Events", May 1990.

7.2-4. "Probabilistic Risk Assessment Surry Nuclear Power Plant Unit 1 and 2 for the Individual Plant Examination", Virginia Power, August, 1991

7.2-5. "Turkey Point Plant Unit 3 and 4 Probabilstic Risk Assessment, IPE Submittal", Florida Power and Light", June, 91.

7.2-6. NUREG 1150 Vol2 "Severe Accident Risks: "An Assessment of Five U.S. Nuclear Power Plants", June 1988.

7.3.7. NUMARC 91-04 "Severe Accident Issue Closure Guidelines", January, 1992